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An integrated regulatory–financial proposal for universal electrification in Uganda beyond the Umeme concession☆

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ABSTRACT

Achieving universal electricity access in Uganda requires rethinking the institutional, regulatory, and financial structure of the distribution segment following the end of the Umeme concession. This paper develops and applies an integrated framework that links least-cost electrification planning with cost-reflective revenue requirements, blended capital flows, and internal cross-subsidies.

A computational model has been built that simulates the full financial architecture of the power distribution segment, generating annual income statements, balance sheets, and cash flows for each actor. The approach introduces two entities: Service-Co, a publicly supervised and privately operated distribution service company, and Finance-Co, a dedicated vehicle that pools public and private funds including grants, concessional loans, commercial debt, and equity to finance investments across grid and off-grid technologies.

Results based on Uganda's National Electrification Strategy show that universal access is achievable without permanent subsidies. Extending the rollout to 2040 reduces annual distribution investment needs by two-thirds and significantly increases returns to both public and private investors. The framework captures the dynamic interaction between tariffs, investment timing, and financing terms, offering a practical tool to design financially robust electrification pathways.

This work provides policymakers with a replicable methodology to align access targets with sector solvency. It shows that, when planned and financed as a single system – integrating all electrification modes in a unique technical, regulatory, and financial plan – universal electrification can become a viable long-term investment.

1. Introduction and literature review

Achieving universal electricity access remains a pressing global challenge. Despite broad consensus on its importance, current efforts are insufficient. The International Energy Agency (IEA) projects that under existing policies, 645 million people will still lack electricity by 2030, with over 85 % of them in Africa (IEA, 2025; IEA, IRENA, UNSD, World Bank, WHO, 2024). Meeting the 2030 target will require a sharp acceleration. Africa would need to connect around 90 million people annually—three times the historical rate (IEA, 2022).

The IEA estimates that about **USD 22–25 billion in investments per year** is needed this decade to provide universal electricity access in Africa by 2030. This annual magnitude of investment, while substantial for African countries, is less than 1 % of global energy investment and comparable to the cost of a single large LNG terminal (IEA, 2022; Rosnes and Vennemo, 2012). Yet actual financing commitments are only a fraction of the required levels, and energy investment in Africa has been declining in recent years (IEA, 2024).

This investment gap is partly driven by the scarcity of bankable projects and a high cost of capital. Interest rates and risk premiums in Africa are two to three times higher than in advanced economies (Briera and Lefèvre, 2024; IEA, 2024). As a result, utilities and off-grid providers struggle to secure financing for network expansion and new connections. Without a fundamental shift in approach, Africa will not meet the 2030 target, with serious consequences for human development and economic growth.

Meeting this challenge requires more than infrastructure and funding. It calls for aligning technical planning with financial and regulatory feasibility. Existing efforts reveal a clear gap in research connecting techno-economic electrification models with financial and regulatory

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analysis (Agutu et al., 2022). On the one hand, energy planners have developed sophisticated models to determine least-cost electrification strategies. Geospatial tools identify optimal mixes of grid extension, mini-grids, and solar home systems to reach unserved communities at minimum cost (Ciller et al., 2019; Ciller and Lumbreras, 2020; Korkovelos et al., 2019). These techno-economic models calculate investment needs for various technologies across space, producing electrification roadmaps (e.g. which villages to connect to the national grid versus via off-grid solutions (Egli et al., 2023). Such analyses, often supported by development agencies, have been applied in many African countries to guide national electrification plans.

Over the past decade, Development Finance Institutions (DFIs) have underwritten more than forty national- or rural-electrification master-plans (Energypedia, 2016; World Bank, 2020a) yet independent diagnostics find that **barely one-half of access-deficit countries even have an approved plan in force** and far fewer have translated those PDFs into physical networks or connections (World Bank, 2020b, 2025a).

However, these models often rely on idealized financing assumptions. They typically apply uniform discount rates over all electrification technologies and overlook the financial constraints of utilities and governments. Most do not integrate business model selection, financing strategies, or consumer affordability into the analysis (Agutu et al., 2022). As a result, their outputs remain disconnected from implementation and plans often fail to materialize. In reality, the viability of any electrification plan hinges on regulatory and financial sustainability: investments must be financed (by utilities, governments, or private sector) and costs recovered in a manner consistent with regulatory frameworks and affordability limits.

Current **electrification models use advanced geospatial methods but often make simplistic assumptions about financing**, which can significantly distort results when those financial factors are properly accounted for. For instance, incorporating realistic cost-of-capital differences can shift hundreds of millions of people from being optimally served by mini-grids to cheaper solar home systems in model results – an insight missed if one assumes concessional finance for all technologies (Agutu et al., 2022).

On the other hand, finance and policy research on electricity access tends to focus on utility finances, tariffs, and regulatory reforms in isolation from the technical planning. There is rich literature on cost-reflective tariffs, subsidies, and utility performance in sub-Saharan Africa, which highlights that most national utilities struggle with financial unsustainability (Klug et al., 2022; Trimble et al., 2016). Tariff reforms are frequently recommended to ensure utilities' revenue covers their costs, and indeed many countries have introduced regulatory regimes based on cost-of-service principles. Under cost-of-service regulation, electricity tariffs are set to allow the utility to recover its operating costs plus a fair return on capital invested in assets (Pérez-Arriaga, 2023). In theory, this should guarantee financial viability and attract investment into generation and networks. In practice, however, implementing cost-reflective tariffs in Africa faces political and socio-economic hurdles. Regulators and governments often hesitate to approve the large tariff increases required to fund major grid expansions, given concerns about affordability and public acceptance. **This leads to a chronic asynchrony between investment needs and regulated revenues**: utilities are expected to rapidly extend networks and connections, but cost recovery through tariffs occurs slowly over the assets' lifetimes.

The result is a financial gap – especially acute in the distribution segment – where up-front capital expenditures can far exceed the cash flows utilities receive from customers in the near term. Many African utilities consequently operate at a loss or depend on government subsidies, which in turn undermines their ability to invest in further connections (Balabanyan et al., 2021; Kojima and Trimble, 2016; Trimble et al., 2016).

Existing research lacks frameworks that iterate between the techno-economic and the financial-regulatory aspects of electrification planning. As a result, there is a gap in understanding how to design electrification strategies that are both cost-optimal and financially viable under regulatory constraints. This gap has been highlighted in calls for more holistic approaches: for instance, recent studies observe that uncoordinated electrification efforts (public or private) are unlikely to yield optimal outcomes and stress the need for governance models aligning technical plans with investment and regulatory mechanisms (Jacquot et al., 2020).

In summary, existing literature has not adequately addressed the integration of techno-economic electrification modelling with regulation and financial planning—a disconnect that this research aims to bridge. The present document offers a regulatory proposal and financial modelling methodology that aims to ascertain a clear path to cost-reflective revenue requirements for all business models and capital requirements to achieve universal electricity access. These concepts are applied to a case study in Uganda, focusing on the distribution sector reform in the post-concession period.

The structure of the paper is as follows. Section 2 reviews the historical development and current configuration of Uganda's institutional and regulatory power sector framework. Section 3 introduces the proposed institutional design to support universal electrification alongside the country's industrialization goals. Section 4 outlines the techno-economic data and research methodology used to build the model, which tests the financial viability of the sector. It also details the interactions between a central financial institution, on- and off-grid operators, the regulatory authority, and financial actors. Section 5 presents the results of the model and the sensitivity analyses. Section 6 discusses the implications of these results and provides practical recommendations. Finally, Section 7 offers a comprehensive summary of the study's conclusions.

2. Background on the Uganda context

Evidence from decades of experience in Sub-Saharan Africa shows that fully public utilities have consistently failed to deliver adequate performance or financial sustainability (Balabanyan et al., 2021; Kojima and Trimble, 2016). Public-private-partnerships (PPPs), when properly designed, present a promising alternative. Positive examples exist in India, in several countries in Latin America, and in some African contexts, although with mixed results (Hosier et al., 2017). Much has been learned from these experiences, in particular in the design of the contracts and in the flexibility of the designs. Uganda is an interesting case example in the distribution segment with Umeme.

Uganda's electricity industry has traversed a complete reform cycle in the space of a single generation. The vertically-integrated Uganda Electricity Board (UEB) was unbundled in 1999, creating separate state-owned companies for generation (UEGCL), transmission and single-buyer functions (UETCL) and distribution-asset ownership (UEDCL), all subject to the newly established Electricity Regulatory Authority (ERA) (Godinho and Eberhard, 2019). Two decades later, in February 2021, the Cabinet decided to recombine these entities into a new public utility, the Uganda National Electricity Company (UNEC). The International Finance Corporation (IFC) described this move as a reversal of what it termed first generation reforms (Tobbias Jolly Owiny, 2022). This historical shift provides a natural experiment for analyzing transaction costs, regulatory credibility, and private sector involvement, which are central topics in current energy economics research.

Macroeconomic performance underpins the debate. Real GDP growth accelerated to 6.1 % in fiscal year 2023/24, sustained by services expansion and rising exports, yet per-capita income still hovers close to the low-income threshold (World Bank, 2025b). Electricity access remains a binding constraint on development: only 45 % of Ugandans were connected to the grid in 2024, well below the Sub-Saharan African average of 51 %, forcing households and firms to rely on costly diesel-based standalone solutions (World Bank, 2024a; Zhang et al., 2025). Moreover, the generation mix is dominated by large hydro plants, which

supplied roughly 80 % of output in 2024; while this confers a low marginal fuel cost, it also exposes the system to hydrological and capital-cost risks (IEA, World Economic Forum, ETH Zurich, Imperial College London, 2024).

The 1999 unbundling ushered in extensive private participation. Nowhere are the results more visible than in the 20-year distribution concession granted to Umeme Ltd. in 2005. Over the life of that franchise technical-and-commercial losses fell from almost 38 % to 16.2 %, the customer base grew nine-fold and collection efficiency approached 99 % (*Umeme Limited, 2024a, 2025*). Yet consumers continued to question tariff levels, and policymakers increasingly viewed the concession's financing structure as a source of "middle-man costs".

Negotiations at concession expiry illustrate the fiscal and regulatory stakes. When Umeme handed the network back to UEDCL on 31 March 2025 it claimed a buy-out value of USD 234 million for its unrecovered regulated asset base, whereas the Auditor-General approved only USD 118 million. The government simultaneously secured a USD 190 million facility from Stanbic Bank to cover the admitted portion while Umeme triggered London-seated arbitration for the balance (Elias Biryabarema, 2025; Njuguna, 2025; Singh, 2025). The episode exemplifies classic hold-up problems and the crystallization of contingent liabilities that unbundled regimes were intended to mitigate.

Against that backdrop the state went ahead with *re-bundling*. UNEC will integrate generation, transmission and distribution under departmental lines while the Ministry of Energy and Mineral Development (MEMD) will provide policy oversight and ERA will retain regulatory powers. Government statements justify the merger on three grounds: coordination economies in system planning, stronger bargaining power for concessional finance, and administrative ease in delivering a politically mandated industrial tariff of USD 0.05/kWh. Critics, including the World Bank Group, warn that vertical reintegration could erode the transparency and hard budget constraints that underpinned early efficiency gains (IEA, World Economic Forum, ETH Zurich, Imperial College London, 2024; Tobbias Jolly Owiny, 2022).

However, Uganda's re-bundling also introduces significant institutional and political economy risks. From an institutional perspective, reintegrating the utility may weaken financial discipline enforced by previous hard budget constraints. UNEC lacks an operational track record and clear accountability structures, creating uncertainty in governance. Leadership appointments risk moral hazard if driven by political patronage rather than merit-based selection. Additionally, without competitive market pressures, the integrated state-run monopoly might rely on government bailouts, diminishing incentives for cost-efficiency.

Moreover, regulatory credibility is at risk despite ERA's nominal independence. Government ownership of the utility could enable informal influence over tariff decisions. Politically motivated tariff freezes or populist pricing policies pose a real threat, exemplified by the government's commitment to a low USD 0.05/kWh industrial tariff. Such underpricing supports industrialization but simultaneously jeopardizes UNEC's financial sustainability. Failure to timely implement cost-reflective tariffs could generate quasi-fiscal deficits, undermining investments in system maintenance and new infrastructure. Although subsidies have been promised to cover potential shortfalls, historical delays in subsidy disbursements are a chronic issue in African power sectors (Kojima and Trimble, 2016). Ultimately, these delays in Uganda would severely impact UNEC's cash flow, limiting network expansion. Mitigating these risks demands robust institutional safeguards. Specifically, Uganda should implement ring-fencing of utility finances, establish transparent procedures for managerial appointments and procurement, and reinforce ERA's independence. These measures are critical to maintaining investor and donor confidence in Uganda's regulatory framework.

Complementing these structural reforms is Uganda's National Electrification Strategy (NES), which provides a quantified roadmap to achieve universal electricity access by 2030. According to (MEMD, World Bank, 2022) meeting this target requires approximately USD 4.7 billion in investments to deliver 10.4 million new connections through grid extension, mini-grids, and standalone solutions. Around 40 % of this capital is expected to come from private sources and blended finance. This underscores the importance of establishing strong institutional, regulatory, and financial frameworks, which are the central focus of this paper, to ensure that the NES can be credibly financed and effectively implemented.

3. Institutional framework proposal

This proposal builds on the decision to rebundle generation, transmission, and distribution. It aims to capture the potential efficiency gains from reduced transaction costs, centralized planning, and improved access to concessional finance (Fetz and Filippini, 2010). At the same time, it seeks to preserve the key benefits of unbundling, including tariff transparency, and keeps the door open to private investment through public–private partnerships.

3.1. The distribution segment of UNEC – a PPP for the national grid: Service-Co

The Electricity Regulatory Authority (ERA) will grant a single 20-year concession to a competitively selected Distribution Service Company (Service-Co). This concession covers the operation, maintenance, and phased expansion of Uganda's national distribution network, which remains publicly owned through the Uganda National Electricity Company (UNEC). The license will include all downstream activities: customer engagement, metering, billing, revenue collection, network densification, and engineering-procurement-construction of new assets. This structure creates a vertically integrated retail franchise, enabling economies of scale and managerial efficiency. The 20-year duration balances the need for long-term cost recovery and efficiency gains with the flexibility to re-tender if contractual performance standards are not met (Ahmed et al., 2022; Hosier et al., 2017; Twesigye, 2023).

Strategic planning will continue to follow the Energy Policy, the National Electrification Strategy (NES), and the Least-Cost Electricity Expansion Plan. These documents define the division of responsibilities. The existing zoning of electrification modes—grid extension, mini-grids, and standalone systems—remains unchanged. Private developers will be responsible for designing mini-grids and will be remunerated under tariffs approved by ERA, following a well-established model (Fajardo et al., 2025; Pérez-Arriaga, 2024). Thirdly, Service-Co will be responsible for the identification of reinforcements, replacements, and low-voltage densification in the legacy grid. In addition, Service-Co will submit investment proposals to ERA for regulatory clearance and cost recovery, along with OPEX costs. Fourthly, the planning of high-voltage extensions of the national grid will be conducted by UNEC's distribution planning unit. The financial resources required for this initiative will be allocated through a centralized financial entity, designated as Finance-Co, which will be elaborated in the following section. Implementation of these extensions will be undertaken under EPC contracts overseen by Service-Co.

Service-Co will be selected through a competitive tender, based on the lowest discounted revenue requirement that meets predefined technical and service-quality standards. Public–private equity participation is encouraged. UNEC and other public entities, such as the National Social Security Fund, may retain a minority or majority stake. This helps mitigate risk and signals government commitment. A detailed Distribution Services Contract will define: (i) allowed revenues and adjustment formulas, (ii) service standards with corresponding penalties and incentives, (iii) procedures for investment approvals, including a fast-track channel for urgent minor works, and (iv) termination provisions. All capital expenditures will be financed by Finance-Co to ensure assets remain on UNEC's balance sheet. Any operational surplus from Service-Co will flow back to Finance-Co, strengthening the long-term viability of the funding framework. To preserve institutional

capacity, the new operator must retain all qualified staff from the outgoing concessionaire for at least three years.

This streamlined public–private partnership architecture limits the number of implementing entities, aligns long-term investment signals with least-cost planning principles, and embeds rigorous performance incentives—thereby providing a durable institutional platform for achieving universal, high-quality electricity access.

3.2. A PPP financial model for the entire distribution – Finance-Co

From a techno-economic least-cost planning standpoint, as well as from a financial perspective, electricity distribution must be treated as an integrated system that optimally combines grid extension, mini-grids and standalone solutions. International experience consistently shows that integrated electrification strategies, compared to fragmented ones, achieve better financial sustainability and improved resource allocation efficiency (Ankel-Peters et al., 2025; Falchetta et al., 2022). Each delivery pathway requires a bankable business model, yet all three should operate under a single, coherent framework for financing, tariff design and cross-subsidization. Such integrated cross-subsidy frameworks have proven crucial internationally in balancing costs across diverse consumer groups, thereby facilitating universal electricity access (CEER, 2020; Estache et al., 2006; Maphosa and Mabuza, 2017). Accordingly, a unified financial strategy that spans the three electrification modalities and includes every participating firm and the Government is indispensable (Briera and Lefèvre, 2024).

This paper proposes a centralized financial strategy to integrate funding across all three electrification modes and to coordinate the actions of utilities, developers, investors, and the government. The goal is to achieve both universal electricity access and industrialization targets. Centralizing financial flows addresses major weaknesses seen in fragmented international financing models, particularly poor coordination, financial instability, and inefficient allocation of resources (Briera and Lefèvre, 2024; Fay et al., 2021; Namita Vikas et al., 2024).

To mobilize and manage the required resources, this paper proposes the creation of Finance-Co, a government-owned financial intermediary. Finance-Co would consolidate public funds and contributions from development partners and reallocate them to the national distribution company, Service-Co, and to off-grid developers. Similar centralized structures have proven effective in other countries.

In Bangladesh, IDCOL successfully blended donor and domestic funding to scale up electrification efforts (Cabraal et al., 2021). Tanzania's Rural Energy Fund (REF) combined donor and government oversight to support rural energy access (Danielsson and Zhou, 2011; World Bank, 2023). Spain's Electricity Deficit Amortization Fund (FADE), created by Royal Decree, helped restore sector liquidity and investment by centralizing financial management (IEA, 2021; Morningstar, 2024). In the Philippines, the Power Sector Assets and Liabilities Management Corporation (PSALM) used a universal charge system to stabilize financial flows to off-grid electrification, offering benefits in administrative efficiency and financial transparency (CEDTyClea, 2025).

Although the Ministry of Energy and Mineral Development (MEMD) and the Ministry of Finance, Planning and Economic Development (MoFPED) retain overall policy authority, it is essential that major stakeholders such as development partners and private investors participate in the governance of Finance-Co. Their involvement is key to ensuring transparency, reinforcing accountability, and improving operational efficiency.

Institutionally, Finance-Co could be established by upgrading the Uganda Energy Credit Capitalization Company (UECCC). An alternative option would be for the Uganda Development Bank (UDB) to assume this role. In either case, limiting the number of implementing agencies is essential to maintain administrative simplicity and ensure efficient execution of the NES and the Least-Cost Electricity Expansion Plan. A relevant international example of administrative simplicity through institutional upgrading rather than creating new agencies is Spain's FADE, which centralized financial management successfully within an existing governmental institution (IEA, 2021; Morningstar, 2024). A well-capitalized UECCC with an expanded mandate, professional staffing and a hybrid governance model that includes the Government, development finance institutions and private investors would be sufficient to discharge the Finance-Co function.

In conclusion, creating Finance-Co as a central and specialized financing vehicle under government leadership, supported by cross-subsidies and coordinated donor contributions, provides a credible path toward financially sustainable and inclusive electrification. This institutional setup directly addresses the financing shortfalls, inefficiencies, and lack of accountability that commonly affect fragmented or decentralized approaches to electrification financing around the world.

3.3. The economic flows

The following Fig. 1 illustrates the economic flows underpinning the institutional framework proposed in this study. The figure highlights how financial resources enter and exit Finance-Co, the centralized financial intermediary.

Inflows to Finance-Co are predominantly composed of the surplus generated by Service-Co. This surplus is calculated as the residual after Service-Co collects regulated tariff revenues and fulfills its regulated revenue requirement. It should be noted that this revenue requirement exclusively encompasses operational expenses. All investment returns must be transferred back to Finance-Co.

Additional financial resources are provided through direct equity contributions from the Government of Uganda and concessional loans and grants provided by development partners (DPs). The strategic deployment of these aggregated financial resources is intended to finance on-grid investments in new electricity distribution infrastructure, as identified in Uganda's NES. Where appropriate, Finance-Co may also finance off-grid assets, allocating them to off-grid companies when needed.

Finance-Co also provides targeted and permanent subsidies to private developers of mini-grids and standalone solar home systems. These subsidies guarantee that decentralized solutions reach cost-reflective revenue levels and remain commercially viable. In addition, Finance-Co covers the cost of capital tied to its outstanding loans and equity contributions.

Through these mechanisms, the structure embeds transparent and explicit cross-subsidization among customer segments—urban and rural, industrial, commercial, and residential—and across different electrification modes, whether on-grid or off-grid.

4. Methodology

The modelling framework developed in this paper is a multi-period simulation tool that integrates financial and operational analysis. It is designed to assess electrification strategies within the institutional structure and constraints of Uganda's power sector. The model aims to project and evaluate the financial viability, funding needs, and tariff implications of achieving universal electricity access alongside industrial development.

The integrated nature of the model ensures consistency between techno-economic operational planning–encompassing grid expansion, off-grid electrification, and operational expenditures–and detailed financial structuring. Specifically, the model generates complete financial statements (Income Statement, Balance Sheet, and Cash Flow Statement) for each key entity involved in electrification effort. The analysis spans from a historical base year of 2021 through scenario projections extending to 2040.

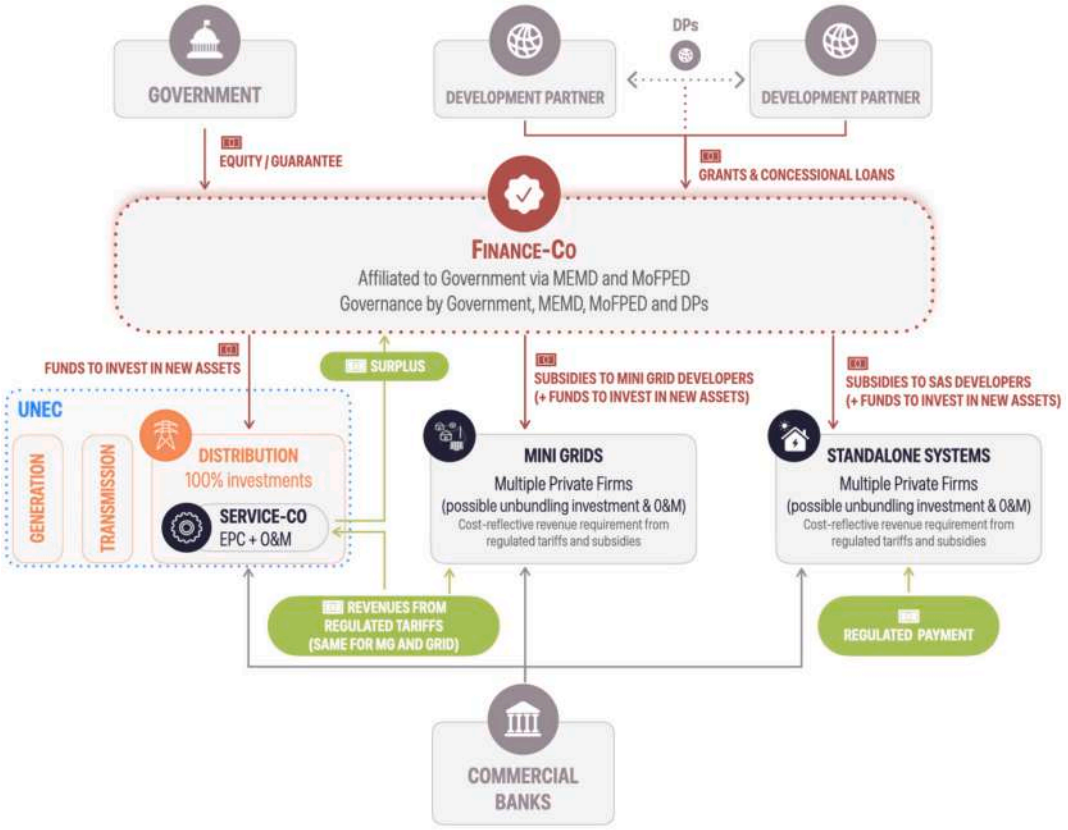


Fig. 1. Finance-Co's role in an integrated financing approach for distribution on-grid and off-grid in the Ugandan Power Sector.

4.1. Model design and simulation procedure

The model is built around modular sub-structures that allow flexible analysis of different institutional configurations. In the case study of Uganda, it includes four main entity-based sub-models that reflect the country's institutional setup. As presented in Table 1, these are: (i) Finance-Co, the centralized financial intermediary; (ii) the incumbent public distribution entities, UNEC/UEDCL; (iii) the private concessionaire, Umeme, which operates until 2025 and is then replaced by Service-Co; and (iv) a unified representation of private off-grid companies, capturing both mini-grid and solar home system (SHS) business models under a single analytical structure.

The model comprises hierarchical, interconnected modules. At the top layer, the model is initialized with the electrification targets and capital expenditure (CAPEX) plans derived from Uganda's National Electrification Strategy (NES). This serves as a common baseline from which scenarios—including accelerated or delayed universal electrification targets—are subsequently assessed.

Each entity-specific sub-model is composed of three distinct analytical dimensions: operational, tariff-regulatory and financial, as illustrated in Fig. 2. The operational dimension projects electricity demand, capital investments, and operating expenses (OPEX). The tariff-regulatory dimension computes the tariff path, tests the compliance with the cost-of-service, and accounts for any subsidies or surpluses. The financial dimension translates these operational outputs into comprehensive financial statements, structured around explicit assumptions of financing conditions and constraints.

4.1.1. Operational module

The operational component of each entity-specific sub-model accounts explicitly for two primary investment categories: i) **CAPEX-due-to-growth**, because of the investments required for achieving new customer connections and accommodating increased demand driven by demographic and economic growth; and ii) **CAPEX-due-to-replacement**, for those investments needed for the substitution or refurbishment of existing infrastructure.

Table 1
Summary of the different submodules and main outputs.

Layer	Function	Principal Outputs
National Electrification Strategy (NES) Driver	Exogenous timetable of connections and CAPEX dictated by Uganda's NES, 2021–2040.	Annual connection targets and corresponding CAPEX deployment.
Entity-Specific Sub-Models (4)	Finance-Co, Incumbent Distribution Company (UNEC / UEDCL), Umeme → Service-Co, and the Off-Grid Private Companies Aggregator. Each sub-model contains: 1) Operational engine (CAPEX/OPEX, losses). 2) Tariff and regulatory engine (demand projection tariff path, cost-of-service test, subsidies/surplus). 3) Financial engine (three-statement accounting with multi-currency capability).	Time-series of Income Statement, Balance Sheet, Cash-Flow Statement, and diagnostic ratios.
System Integrator	Consolidates entity cash flows, allocates cross-subsidies via Finance-Co, and executes the tariff-setting iteration until global cost recovery is achieved.	Cost of service equilibrium, subsidy schedule, and sector-wide financial metrics (NPV, IRR, DSCR trajectories).

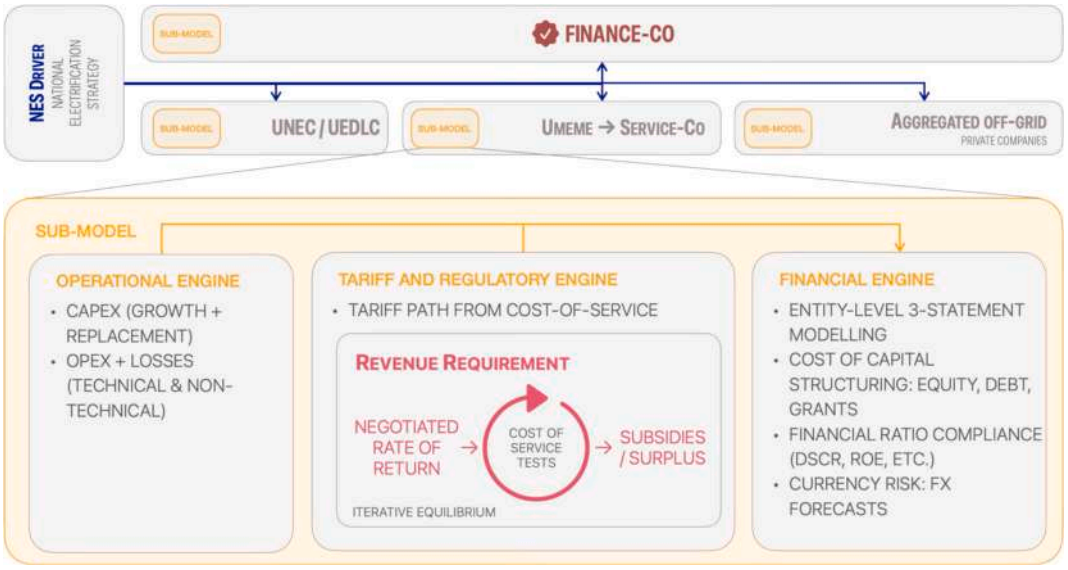


Fig. 2. Schematic structure of the model.

Assets are depreciated according to their useful economic lives using detailed schedules aligned with regulatory accounting standards. Operating expenses are projected based on historical cost benchmarks from utility financial reports and NES-derived unit costs, differentiating clearly between operational maintenance expenses linked directly to installed infrastructure and general administrative retail costs associated with the growing customer base.

Additionally, the model explicitly considers technical and non-technical losses. Technical losses—typically subject to regulatory targets—and non-technical losses, comprising energy theft and non-paid bills ("bad debts"), are factored into the operational expense projections, reflecting real-world operational challenges faced by distribution utilities in developing regions.

4.1.2. Tariff and regulatory module

This module systematically translates demand projections into tariff-derived revenues. Electricity demand is forecasted across three distinct consumer categories: residential, commercial, and industrial, each with differing consumption patterns and tariff structures. Tariffs are initially set according to the prevailing regulated tariff structure approved by the Electricity Regulatory Authority (ERA) and are subsequently projected, adjusting annually for local inflation indices.

The tool employs an iterative numerical algorithm designed to ensure financial equilibrium at the entity level, specifically by achieving an orthodox annual revenue requirement for each regulated entity (Umeme/Service-Co and aggregated off-grid companies). This revenue requirement reflects the total allowed revenue each entity must recover annually, as calculated through a standard cost-of-service regulation approach (Gómez, 2013a, 2013b; Reneses et al., 2013). It incorporates operating expenses, depreciation, and allowed returns on invested assets, the Regulated Asset Base (RAB), ensuring sustainability and compliance with regulatory principles – see Eq. (1).

The algorithm begins by establishing an initial revenue forecast based on projected demand, prevailing tariff levels, and regulated revenue targets. For each subsequent iteration, the following analytical steps are conducted:

1. **Revenue Projection**: Revenues for each entity are projected using the initially assumed or previously converged tariffs, adjusted annually for inflation and demand forecasts.
2. **Revenue Requirement Calculation**: In a given year t, for each entity i, the annual revenue requirement $RR_{t,i}$ is rigorously calculated with this equation:

$$RR_{t,i} = OPEX_{t,i} + Depreciation_{t,i} + \left(RAB_{t,i}\ x\ WACC_{t,i}\right) \quad (1)$$

While the literature often refers generically to the "allowed rate of return," our model -and the entirety of this paper- explicitly adopts the Weighted Average Cost of Capital (WACC) as the relevant metric. This parameter serves as the key driver of the return on the RAB and, by extension, the overall revenue requirement and resulting tariff. The importance of WACC becomes particularly salient in the context of Uganda's regulatory transition from the end of Umeme's concession—during which a 20 % return was applied (Twesigye, 2023) - to a new post-concession regime. As such, variations in the assumed WACC across scenarios critically shape outcomes related to subsidy needs, financial sustainability, and tariff affordability.

3. **Subsidy or Surplus Determination**: The model compares projected tariff-based revenues $\left(Rev_{t,i}\right)$ against the calculated revenue requirement $\left(RR_{t,i}\right)$. If a deficit occurs $\left(Rev_{t,i} < RR_{t,i}\right)$, a subsidy is recorded, indicating a call for external financial support from Finance-Co. Conversely, a surplus $\left(Rev_{t,i} > RR_{t,i}\right)$, indicates that excess revenues are directed back into Finance-Co, available for redistribution or reinvestment. Formally, the subsidy or surplus $\left(SS_{t,i}\right)$ for each entity i at time t is represented as:

$$SS_{t,i} = Rev_{t,i} - RR_{t,i} \quad (2)$$

Where:

- If $SS_{t,i} < 0$, entity i requires a subsidy from Finance-Co.
- If $SS_{t,i} > 0$, entity i contributes a surplus back to Finance-Co.

4. **Convergence and Equilibrium Condition:** Iterations continue until the subsidies and surpluses stabilize within a predefined numerical tolerance (ε), ensuring that the revenue equilibrium condition across entities is satisfied annually. Mathematically, the convergence condition is expressed as:

$$\left| SS_{t,i}^{(k+1)} - SS_{t,i}^{(k)} \right| < \varepsilon, \quad \forall i, t \quad (3)$$

This iterative algorithm thus ensures that each entity's financial requirements are explicitly balanced on an annual basis, facilitating a

realistic and institutionally coherent allocation of resources across the integrated electrification framework.

5. **Financial Equilibrium Condition**: The overall financial equilibrium for the integrated system over the analysis horizon can be expressed as achieving balance in the present value of cumulative surpluses and subsidies at the central financial intermediary Finance-Co:

$$\sum_{t=0}^{T}\sum_{i=1}^{3}\frac{SS_{t,i}}{(1+WACC)^t}\geq 0 \tag{4}$$

Eq. (4) articulates the condition underpinning the overall financial sustainability of the electrification strategy: over the entire planning horizon, the discounted surpluses and subsidies must balance out at the centralized financial entity level, ensuring system-wide financial neutrality.

4.1.3. Financial module

The financial module systematically constructs annualized Income Statements, Balance Sheets, and Cash Flow Statements for each entity by integrating outputs from the operational and revenue modules. This module incorporates explicit assumptions about the capital structure, combining equity, concessional and commercial debt, and grants in alignment with projected capital requirements.

The model incorporates financial parameters such as equity return expectations, dividend payout policies, commercial loan conditions (interest rates, repayment schedules, grace periods), and the availability of concessional financing, which is directly or indirectly linked to investments in electrification. The financial structure is optimized via an iterative process that must respect predefined constraints derived from standard financial ratios.

The simulation starts with a provisional financial plan combining equity, debt, and grants is established for each entity, including Service-Co, Finance-Co, and aggregated off-grid providers (mini-grids and standalone systems). Service-Co's regulated tariffs cover its operation and maintenance expenses, generating a surplus transferred to Finance-Co. Expansion and asset renewal of the distribution network are funded by Finance-Co and owned by UNEC, recorded explicitly within UNEC's distribution accounts, thereby excluding these from Service-Co's financial planning. Off-grid providers finance operations through equity, debt, customer tariffs, and subsidies via Finance-Co. Total financing requirements encompass capital expenditures, negative operating cash flows until breakeven, and financial outflows dictated by the capital structure.

Subsequently, financial viability is assessed by comparing projected cash flows with benchmark values for key financial ratios. The analysis focuses on several indicators: the debt service coverage ratio (DSCR), debt-to-EBITDA ratios (disaggregated into total, net, commercial, and concessional), the interest coverage ratio, return on capital employed (ROCE and net ROCE), return on equity (ROE), and the debt-to-property, plant, and equipment (PP&E) ratio. These benchmarks ensure financial soundness, regulatory consistency, and alignment with investor and lender expectations.

If any ratio exceeds its threshold, the model adjusts financial instruments such as concessional borrowing levels or development finance institution (DFI) grants. The simulation then restarts. This iterative process continues until the model converges to a financially sustainable plan. Sustainability is defined as the point at which regulated tariff revenues, including cross-subsidies, fully cover operational, capital, and financing costs by the target year, with no need for further external financial support.

However, even when the model reaches a technically sustainable outcome, the resulting plan may not be feasible within the country's actual constraints. The required volume of concessional finance, the pace of implementation, or the institutional demands may exceed what is realistically achievable. In such situations, and when increasing the grant share beyond reasonable levels is not a viable option, the only credible alternative is to extend the timeline for reaching universal electricity access. A longer horizon enables a more gradual rollout, aligns investment needs with fiscal and institutional capacity, and enhances the practical viability of the strategy.

Additionally, the financial module ensures compliance with essential accounting relationships. Specifically, Eq. (5) ensures that each annual cash movement reconciles with the closing cash balance -an essential robustness check for the three-statement model.

In a given year t;

$$Cash_{t-1}+CFO_t+CFF_t+CFI_t=Cash_t \tag{5}$$

where *CFO*, *CFF* and *CFI* are the cash flows from operations, financing, and investment respectively.

And Balance Sheet coherence is maintained via:

$$\Delta Asset_t=\Delta Liabilities_t+\Delta Equity_t \tag{6}$$

enforcing year-on-year coherence between investment activity, working-capital changes, and their financing.

To analyze scenarios such as extending the electrification target from 2030 to 2040, the model is run iteratively by adjusting the investment timelines and financing strategies within the simulation procedure. Each scenario recalculates financial outcomes and compliance with ratio constraints to identify necessary adjustments in the financing mix, capital structure, and potential subsidies. The results from such analyses, particularly the implications for financial viability, tariff structures, and required concessional funding levels, are detailed explicitly in the subsequent results section.

4.1.3.1. Currency module. Recognizing the practical complexities of multi-currency financial planning, the financial module includes a dedicated currency module. Revenues and local operational expenditures are denominated primarily in local currency (Ugandan Shillings), while financing sources (equity, commercial and concessional debt) are typically denominated in hard currencies (USD).

The currency module explicitly projects exchange rates based on differential inflation forecasts provided by the International Monetary Fund (IMF) and simulates forward-contract strategies for currency hedging. This facilitates robust evaluation of currency-related financial risks, including the impact of currency depreciation on debt-service obligations and investor returns.

4.2. Data and assumptions

This section details the specific quantitative inputs used to parameterize the integrated model described in prior sections, relying predominantly on publicly accessible primary data sources validated against secondary market reports for robustness and plausibility.

Central to the analysis is the Government of Uganda's (GoU) National Electrification Strategy (NES), which establishes two core policy objectives: achieving universal electricity access by 2030 and promoting accelerated industrialization through competitively priced industrial tariffs.

According to this plan, as can be seen in Fig. 3, the majority of the population currently without access (53 %) would be most cost-effectively served through Tier-1 standalone solar systems, due primarily to their remote geographical distribution. Grid extensions and densification efforts would provide electricity to approximately 45 % of the unserved households, while mini-grids would account for a minor share (2 %). Given the varying unit costs associated with these technologies, investment shares differ notably from consumer connection shares, with grid extensions capturing the majority of investment (83 %), mini-grids a smaller portion (8 %), and standalone systems representing 9 %.

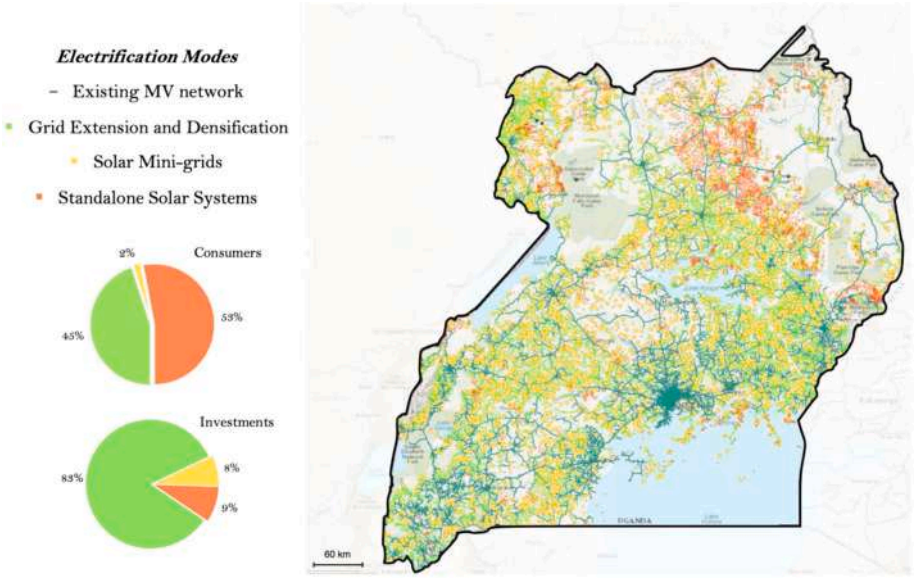


Fig. 3. Summary of the outcomes of the National Electrification Strategy (NES) techno-economic electrification plan for Uganda. Source: Authors' elaboration (data from the Sectorial Planning and Policy Analysis Department, 2025; see "NES" worksheet in base-case replication model).

Between 2021 and 2025, the model baseline uses actual deployment and short-term certified projections, not long-term NES goals. In terms of off-grid achievements, forty-eight mini-grids were commissioned by mid-2024 by Uganda's Rural Electrification Agency and its successor under MEMD (International Solar Alliance, MEMD, 2024). Despite the absence of annual data, 25 sites were co-financed by BMZ/GIZ, the EU, and the Ugandan government, with a total investment of €9.8 million—€3.7 million from European partners and the remainder from national funds. By mid-2022, these mini-grids had provided electricity to around 20,000 households and 150 businesses (GIZ, DKTI, European Union, 2022). In light of the limited data available on standalone systems, the model operates under the assumption that their deployment trend aligns with that of mini-grids, in accordance with the NES.

On-grid expansion also advanced during this period. Uganda Electricity Distribution Company Limited (UEDCL) reported 3751 new connections in 2022 and 14,195 in 2023 (UEDCL, 2023). Umeme Ltd. reported a larger volume of densification: 121,131 new connections in 2022, 191,874 in 2023, and 139,196 in the first half of 2024 (Umeme Limited, 2024b).

To meet the 2030 universal electrification target, the remaining required connections are evenly distributed across subsequent years, resulting in a marked increase—from approximately 350,000 new connections in 2025 to 1.72 million in 2026. These increments include grid extensions, mini-grids, and standalone solar systems, as depicted in Fig. 4, which also outlines the corresponding annual CAPEX investments needed.

The following Table 2 systematically organizes these assumptions and input data under the key different categories.

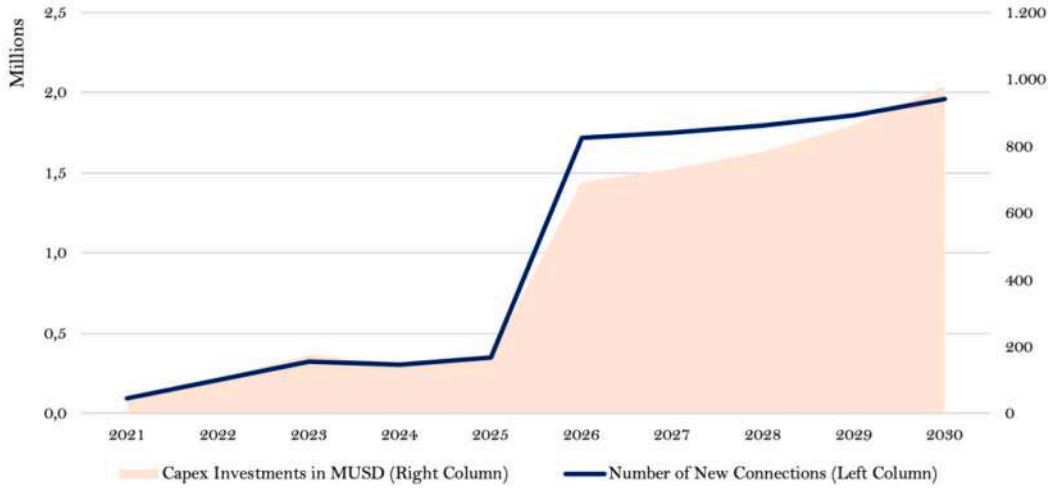


Fig. 4. Annual CAPEX investments (shaded area, right axis) and incremental connections (blue line, left axis) under the National Electrification Strategy. Source: Authors' calculations (based on NES connection targets and unit-cost data; see "NES" worksheet in base-case replication model). (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

Table 2
Summary of the data sources and assumptions of the model.

Thematic block	Parameter	Base-case value	Time frame	Principal source(s)
Planning horizon	Analysis window	2021–2040	–	–
Electrification trajectory	Base Case target electrification rate	100 % by 2030	2021–2030	NES (MEMD, World Bank, 2022)
	Period for financial stabilization	2031–2040	2031–2040	–
Macroeconomic context	Real GDP growth	IMF path (start-value 5.5 %)	2021–2040	(IMF World Economic Outlook, 2025)
	Inflation—USD	IMF path (start-value 4.7 %)	2021–2040	ibid.
	Inflation—USh	IMF path (start-value 2.2 %)	2021–2040	ibid.
	Corporate tax rate	30 %	2021–2040	(PwC, 2025)
Demand and demographic growth	Population growth (rural & urban)	3.3 % p.a.	2031–2040	(de Abajo, 2023; Pérez-Arriaga et al., 2022)
	Demand per customer—pre-2025	(GDP + 2 %) trend	2021–2025	ibid.
	Demand per customer—post-2025	Interpolated to NES 2030 level, thereafter GDP + 2 %	2026–2040	NES (MEMD, World Bank, 2022); authors' interpolation
Investment cost trajectory	Grid extension connection cost	USD 1088 / connection	2021–2030	NES (MEMD, World Bank, 2022)
	Densification connection cost	USD 730 / connection	2021–2030	ibid.
	Mini-grid connection cost	USD 1519 / connection	2021–2030	ibid.
	Standalone solar home 3 W system	USD 76 / connection	2021–2030	ibid.
	CAPEX replacement	Linked to the depreciation schedule	2021–2040	Authors' modelling consistent with NES asset lives (de Abajo, 2023; Pérez-Arriaga et al., 2022).
Tariff baseline & indexation	Residential tariff	ERA Q4–2024 nominal value	2021–2024	(ERA, 2025)
	Commercial tariff	ERA Q4–2024 nominal value	2021–2024	ibid.
	Industrial tariff 2025	USD 0.05 / kWh	Effective Jan 2025	Model Assumption, (Staff, 2024)
	Inflation pass-through	Tariffs escalated annually with inflation	2025–2040	Model Assumption
	Minigrids tariff	Same tariff as on-grid customers	2025–2040	Model Assumption
	SHS "regulated payment"	USD 12 / hh yr	2025–2040	(Adkins et al., 2012)
Financing parameters	Grants	Disbursed pro-rata with CAPEX; no repayment	2021–2030	(de Abajo, 2023; Pérez-Arriaga et al., 2022)
	Concessional debt	2 % interest; 6-yr grace period; amortized to 2040	2021–2040	ibid.
	Commercial debt	8 % interest; no grace period	2021–2040	ibid.
Operating cost drivers	Upstream energy cost	USD 0.084 / kWh	2021–2040	NES (MEMD, World Bank, 2022)
	Technical and non-technical losses	Market estimates cross-checked with the NES	2021–2040	NES (MEMD, World Bank, 2022; Pérez-Arriaga et al., 2022; Umeme Limited, 2024a)
	O&M (grid, mini-grid, SHS)	% of cumulative CAPEX	2021–2040	ibid.
	Administrative cost	USD /yr customer	2021–2040	ibid.

4.3. Empirical calibration and validation

The model was calibrated against audited financial and technical indicators from Umeme and UEDCL for the period 2018 to 2024. Technical losses decline from 18 % in 2021 to 16 % in 2025, mirroring the downward trend reported by Umeme, where losses fell from 38 % in 2005 to 16.2 % by 2023 (*Umeme Limited,* 2024b, 2024c, 2025). The service territories of UEDCL exhibit a similar trend, albeit at a slower rate, and provide the upper bound for calibration (UEDCL, 2023). ERA's industry dataset also reflects a decline in system losses—from 19.1 % in 2021 to 17 % in 2024—which the model replicates both in direction and magnitude (ERA, 2024a).

The growth of customer connections in the model was aligned with observed trends as well: the combined number of grid customers modeled for 2025 closely matches the total customers served nationally when Umeme's 20-year concession ended. The model projects 2.25 million grid-connected customers by end-2025, remaining within 5 % of the 2.4 million customers reported by ERA for 2023, once Umeme's 2025 additions are incorporated (ERA, 2024b; Umeme Limited, 2024a).

In terms of tariffs, the model's starting tariff schedule replicates ERA's actual Q4 2024 approved tariffs by consumer category, providing a realistic revenue baseline. These measures anchor the simulation in reality and allow a like-for-like comparison to historical outcomes. The simulation closely tracks quarterly tariff adjustments, with deviations remaining within 2 % in real terms over 2021–2024 (ERA, 2023, 2024c, 2025). Modeled EBITDA margins lie within a 5 % range of those reported by Umeme for 2020–2023 (Umeme Limited, 2024c).

Using these calibrated inputs, we found that the model's outputs closely track past performance. Key financial and operational indicators – loss reduction, customer growth, and tariffs – fall within a narrow margin of historical values. Residual deviations stem from three transparent assumptions. First, tariff changes are smoothed on an annual basis, whereas ERA occasionally front-loads or defers quarterly increments, creating timing gaps in revenue collection. Second, subsidies flow on schedule in the model; in practice, disbursements to cover the industrial tariff and rural connections have faced short delays that momentarily affect utility liquidity. Third, the simulation tracks two loss trajectories simultaneously: the higher, company-specific path reported by Umeme and UEDCL, and the lower loss factors approved and embedded in ERA's tariff methodology; the model assumes gradual convergence of the two curves to about 14 % by 2030. This dual treatment preserves consistency with historical utility accounts while reflecting the regulatory benchmark used in tariff computation.

Under these standard, tractable modelling assumptions, the simulation reproduces historical movements in losses, customer growth and tariffs with high fidelity. This close alignment indicates that the analytical framework is both empirically grounded and sufficiently flexible to accommodate updated regulatory targets, providing a credible basis for the forward-looking scenarios explored in the following Section 5.

5. Results

5.1. Base case scenario

This section presents the empirical evidence that underpins the proposed post-concession distribution architecture for Uganda, integrating the model described in Section 4.1 with the priorities articulated by the Government of Uganda (GoU) and the National Electrification Strategy (NES). This section assumes the achievement of universal access by 2030 as the Base Case Scenario.

The primary insight derived from the Base Case Scenario analysis indicates that implementing Uganda's NES is financially feasible in the considered time frame via an acceptable tariff path and a carefully structured combination of blended financial resources, contingent upon adhering strictly to the strategic recommendations outlined in this report. Nevertheless, achieving this objective presents significant challenges, particularly given the notable discrepancy between the current investment levels in Uganda's electricity distribution sector and the substantially greater financial requirements identified in this analysis.

Notably, the financial viability of this scenario hinges critically on several underlying assumptions. This viability also presupposes robust electricity demand growth resulting from accelerated electrification, significant inflows of concessional financing, and substantial grant funding. The design explicitly leverages cross-subsidization across consumer segments and electrification modalities, thereby ensuring remunerative returns sufficient to mobilize private capital for off-grid and mini-grid solutions.

The financial modelling detailed here spans two distinct periods within the broader timeframe of 2021–2040. The initial period (2021−2030) corresponds predominantly to intensive electrification efforts, involving significant capital expenditures and strongly growing operational expenditures as detailed in Section 4.2. During this phase, the primary source of funding for total distribution costs is grants from development partners (DPs) and equity from the GoU, supplemented by concessional funding and the end-user tariff revenues. According to the model, financial stability and self-sufficiency are reached by 2040. By that year, all concessional debt will have been fully amortized, and equity contributions will have been remunerated with the returns agreed upon. From that point onward, regulated tariffs are sufficient to cover the full revenue requirement of the distribution segment, including both grid-connected and off-grid services.

The Base Case Scenario mirrors the investment profile defined in Uganda's National Electrification Strategy (NES), with a substantial concentration of capital expenditure between 2026 and 2030. As shown in Table 3, this period represents the core phase of infrastructure deployment required to meet the universal access objective by 2030.

Annual investment needs vary over the planning horizon. Between 2026 and 2030, the average annual requirement is approximately USD 810 million, covering both grid-connected and off-grid solutions. For on-grid infrastructure, total investment in expansion, maintenance, and reinforcement during this period amounts to USD 3.37 billion. An additional USD 1.6 billion is projected for the 2031 to 2040 period to meet continued population growth and rising electricity demand.

Off-grid electrification similarly demands significant capital outlays, with cumulative investment requirements reaching USD 678 million during 2026–2030, followed by more than USD 1 billion between 2031 and 2040. These later-stage investments are driven primarily by demand growth in remote areas and the periodic replacement of off-grid technologies—namely batteries, photovoltaic panels, and inverters—whose operational lifespans necessitate reinvestment.

To meet the capital requirements associated with achieving the NES targets between 2026 and 2030, the financial intermediary Finance-Co must mobilize a total of approximately USD 3 billion in external

Table 3
Investment profile 2021–2040 (USD million). Source: Authors' calculations (compiled from the "Summary of Tables" worksheet in base-case replication model).

	2021–25	2026–30	2031–40	Total
On-grid – expansion, maintenance & reinforcement	197	3371	1642	**5210**
Off-grid – mini-grids & standalone systems	95	678	1077	**1851**
Total annual average (USD million)	**59**	**810**	**272**	–

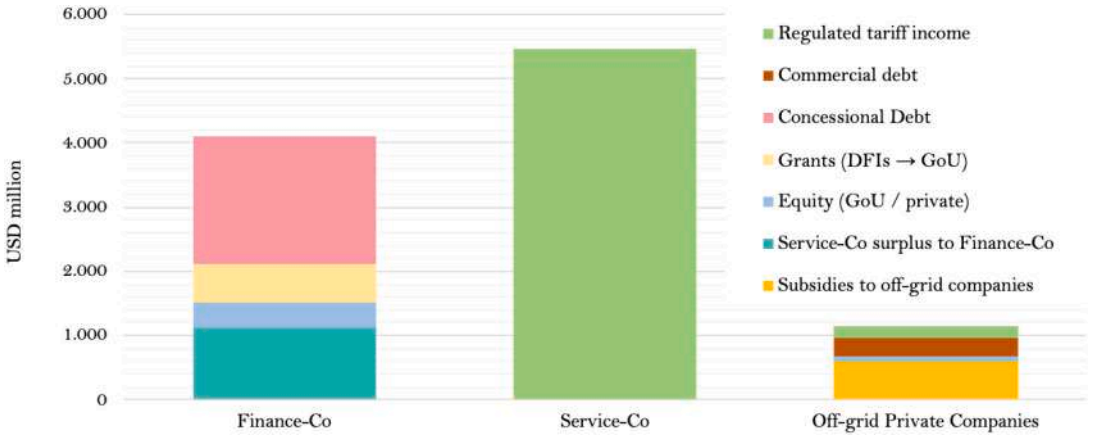


Fig. 5. Financing composition 2026–2030 to achieve 100 % electrification by 2030. Source: Authors' calculations (see "Summary Financing" worksheet in base-case replication model).

financing. As summarized in Fig. 5, this financing package is composed of USD 2 billion (49 %) in concessional debt—characterized by favorable terms including a six-year grace period and a 2 % interest rate—USD 600 million (15 %) in grants, and USD 400 million (10 %) in equity contributions from the Government of Uganda (GoU).

Complementing these external sources, Finance-Co also benefits from internal revenue streams. Specifically, regulated tariffs collected by Service-Co generate operational surpluses totaling USD 1.12 billion, which are transferred upstream and account for approximately 27 % of Finance-Co's total investment needs over the 2026–2030 period. This internal cash flow enhances the financial sustainability of the financing structure and reduces dependence on external capital injections.

Service-Co's financial viability is ensured through a regulated tariff regime that covers full operational expenditures (OPEX) while also producing positive net operational income. These surpluses, channeled to Finance-Co, serve as an additional mechanism for cross-subsidization

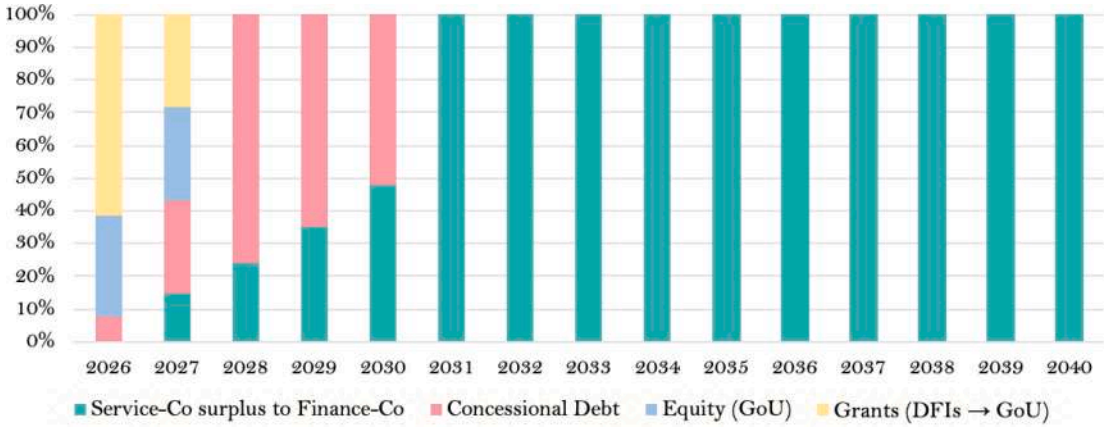


Fig. 6. Annual evolution of the sources of financing of Finance-Co during the 2026–2040 period. Source: Authors' calculations (see "Summary Financing" worksheet in base-case replication model).

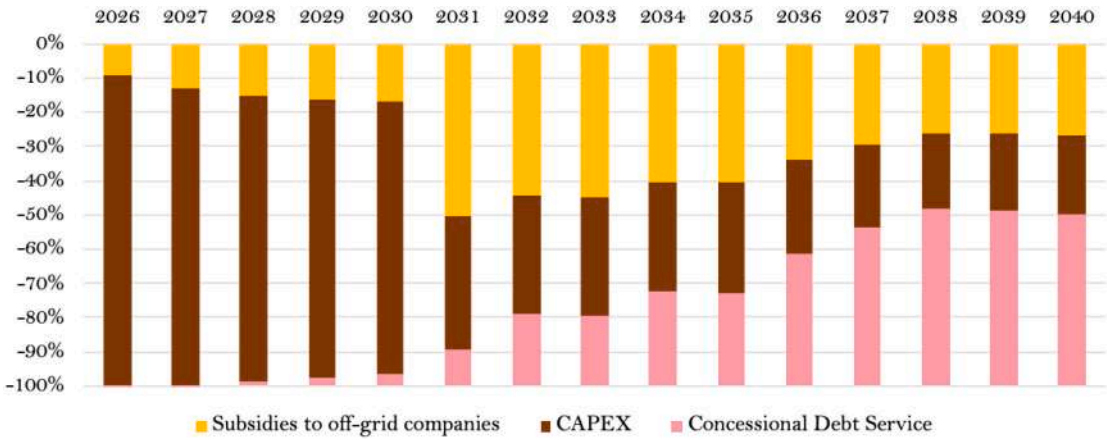


Fig. 7. Annual evolution of the uses of financing of Finance-Co during the 2026–2040 period. Source: Authors' calculations (see "Summary Financing" worksheet in base-case replication model).

within the integrated electrification framework.

Private off-grid developers play a central role in the electrification strategy. Supported by regulated subsidies and cost-reflective revenue requirements, they are expected to finance close to 50 % of their capital needs through internal resources. Commercial debt represents 24 % of the total (USD 275 million), while equity covers around 8 % (USD 95 million). To ensure investment viability and achieve the agreed 12 % rate of return on the investments, regulated subsidies are required to complement tariff revenues, which account for USD 188 million (16 %). These subsidies cover the remaining 51 % of total off-grid investment needs during this period, amounting to almost USD 600 million.

Fig. 6 and Fig. 7 provide a visual representation of the financial flows of Finance-Co from 2026 to 2040, detailing the sources and uses of funds. The financing structure evolves progressively, as illustrated in Fig. 6.

In the initial years, equity contributions from the Government of Uganda act as a catalytic first-loss tranche. As a result, grant financing is unlocked, enabling this blended structure for capital deployment during the infrastructure rollout's peak phase. Concessional debt is mobilized subsequently, once revenue streams from regulated tariffs begin to materialize and provide sufficient debt service capacity. From 2030 onward, the system relies increasingly on internal cash flows, with Service-Co's surplus transferred to Finance-Co covering key expenditures.

The negative values along the y-axis in Fig. 7 denote outflows from Finance-Co's perspective, reflecting the disbursement of funds toward investment uses across the system. These include all investments in electrification efforts, ongoing replacement-related capital expenditures, full debt service obligations (interest and amortization), and continued subsidies to off-grid developers. These measures ensure the viability of their business models and a sustained 12 % return on equity. The full set of financial statements and diagnostic ratios for each company are provided in the Appendix, detailing the financial performance and structure of all entities involved.

In conclusion, while achieving the NES targets by 2030 through the proposed blended finance model is demonstrably viable, significant strategic commitment from governmental and development stakeholders will be imperative. Effective execution will depend on securing the envisioned big financial contributions, managing cross-subsidies efficiently, and realizing anticipated demand growth, collectively ensuring sustained financial viability and infrastructure development through 2040.

5.2. *Sensitivity analysis: extending the universal-access target to 2040*

This sensitivity analysis explores an alternative scenario in which Uganda reaches universal electricity access by 2040 instead of 2030, while maintaining all regulatory, tariff-setting, and industrialization policies constant. The objective is to isolate the financial and operational implications of extending the timeline by redistributing the same total investment over a longer period.

The extension directly addresses the financial constraints and implementation bottlenecks identified in the Base Case. Reaching the 2030 target required average annual distribution capital expenditures of USD 810 million between 2026 and 2030, a level that exceeds Uganda's historical capacity to execute and absorb such investments. By shifting the timeline to 2040, investment needs are smoothed over time, easing fiscal pressure and improving implementation feasibility. This makes the overall strategy more realistic and better suited to existing institutional capabilities. The main comparative results of this scenario are summarized in Table 4.

Quantitatively, extending the target year markedly reduces the annual investment burden. Average annual distribution CAPEX between 2026 and 2030 declines by approximately 67 %, from almost USD 810 million under the Base Case to around USD 270 million. Specifically, on-grid investment commitments reduce significantly from USD 3.4 billion in the Base Case scenario to USD 1.1 billion. Off-grid investments similarly drop from USD 0.7 billion to USD 0.2 billion for the same period. This redistribution reduces the funding requirements of Finance-Co dramatically, from USD 3 billion in the original scenario to almost USD 0.7 billion, composed of USD 200 million in grants, USD 100 million in government equity, and USD 370 million in concessional debt.

The revised capital structure strengthens early-stage solvency and supports long-term financial sustainability. Model simulations show that Finance-Co's equity internal rate of return peaks at 65.6 % in 2031, driven by front-loaded revenue inflows and modest initial equity contributions. As debt is gradually amortized and retained earnings accumulate, the IRR declines to around 42 % by 2040. This trajectory reflects the expected reduction in marginal returns as the system transitions to a lower-risk, internally financed profile. At the same time, the Debt Service Coverage Ratio (DSCR) exceeds 30 in 2031, supported by conservative leverage and stable net cash transfers from Service-Co. This strong ratio indicates low financial risk during the initial years of the investment cycle, reinforcing the credibility of the proposed financing model.

Off-grid private companies also experience improved early-stage returns under the revised schedule. Equity IRR for these entities increases to approximately 29.5 % by 2031, subsequently moderating to about 22.7 % by 2040, comfortably surpassing the minimum threshold required to attract private capital. This favorable financial profile remains largely due to the deferral of substantial investments while maintaining regulatory subsidies aligned with revenue requirements.

Extending the electrification deadline carries important policy implications. A longer timeline gives the Ugandan government and development partners more room to mobilize financial resources. It lowers the immediate need for high volumes of grants and concessional loans. For the same objective, required grants fall from USD 600 million to USD 200 million, while concessional debt drops from USD 2 billion to USD 370 million.

This extended period also creates space for gradual implementation of tariff adjustments and improvements in collection efficiency. Such sequencing reduces political and operational risk and supports long-

Table 4
Overview of key comparative results in the two scenarios. Source: Authors' calculations (compiled in "Summary of Tables" worksheet; derived from the 2030 base-case model and the 2040 target scenario model).

Metric	Base Case (100 % in 2030)	2040 target scenario	Δ
Average annual distribution CAPEX, 2026–30	USD 809.8 million	**USD 269.9 million**	– 66.7 %
– On-grid CAPEX 2026–30	USD 3.4 bn	**USD 1.1 bn**	– 66.7 %
– Off-grid CAPEX 2026–30	USD 0.7 bn	**USD 0.2 bn**	– 66.7 %
Finance-Co funding need, 2026–30	USD 3.0 bn	**USD 0.7 bn**	– 77.7 %
Funding mix 2026–30 (Grants / Equity / Conc. debt)	14.6 % / 9.7 % / 48.6 %	**13.2 % / 6.6 % / 24.5 %**	
Off-grid subsidies, 2026–30	USD 0.6 bn	**USD 0.3 bn**	– 56.9 %
Equity IRR – Finance-Co (2031)	17.7 %	**65.6 %**	↑
Equity IRR – Off-grid firms (2031)	20.7 %	**29.5 %**	↑
Finance-Co DSCR (2031)	12.8×	**> 30×**	↑

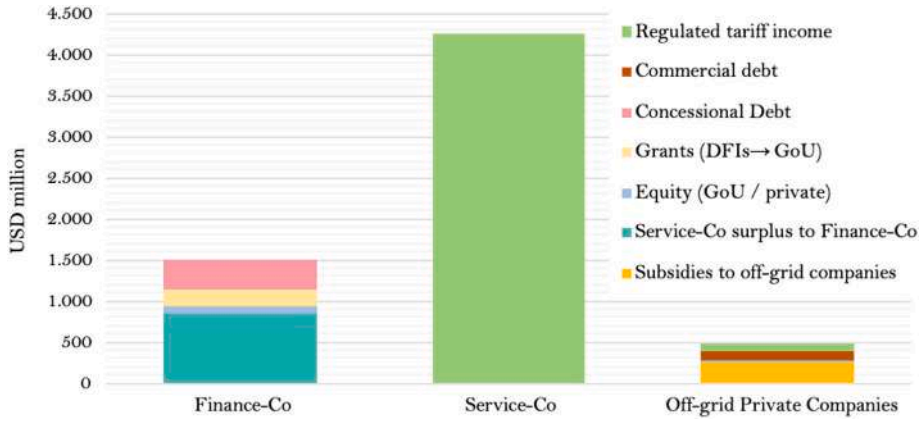


Fig. 8. Financing composition 2026–2030 to achieve 100 % electrification by 2040. Source: Authors' calculations (see "Summary Financing" worksheet in extended-target (2040) replication model).

term financial stability. At the same time, the scenario maintains strong incentives for off-grid investment, preserving the conditions necessary for continued private sector involvement. The financial composition of this scenario over the period 2026 to 2040 is shown in Fig. 8.

In conclusion, the sensitivity analysis confirms that achieving universal electricity access by 2040 is financially viable under the proposed regulatory and financial framework. While the model demonstrates that a 2030 target is also feasible, the 2040 timeline improves the overall bankability of the plan by easing annual financing needs and reducing reliance on rapid concessional capital mobilization. This extended horizon better matches Uganda's current fiscal and institutional capacity, allowing for more efficient resource allocation and lowering financial risk.

Rather than weakening ambition, a 2040 target strengthens the credibility of the electrification strategy. It provides a more realistic path that maintains investor confidence while ensuring steady progress toward universal access. To support this trajectory, the government must uphold policy stability, sustain the proposed grant flows, and continue implementing regulatory reforms that reinforce the long-term financial sustainability of the sector.

6. Discussion

The results presented in the previous section provide strong empirical support for the viability of a new regulatory and financial model tailored to Uganda's distribution segment. They show that universal electricity access is achievable on a financially sustainable basis when planning, financing, and regulation are integrated into a coherent framework. The model combines cost-reflective revenue requirements, internal cross-subsidies, and concessional capital. Together, these elements generate sufficient internal cash flows to cover debt service, provide returns to equity, and sustain the distribution infrastructure over time.

However, while both timelines are financially viable, achieving universal access by 2030 would require mobilizing unprecedented volumes of concessional finance in a very short period. Given current institutional and market conditions, this appears unlikely. A more gradual path toward 2040 remains consistent with long-term sustainability and is more realistic within Uganda's financing and implementation capacity. This underscores the importance of adapting electrification strategies to national contexts. For other countries facing similar challenges, particularly those that have yet to begin large-scale electrification efforts, aligning the ambition of the access target with actual capacity to raise and deploy capital will be essential. Extending the timeline can be more credible than relying on extreme increases in grants.

A key result from the quantitative analysis is the central role of Finance-Co as a unified financing vehicle for all electrification activities. Consolidating financial flows within a single entity offers clear advantages over fragmented or project-specific approaches. These include economies of scale, the ability to pool and target cross-subsidies, and greater appeal to private investors. The model delivers consistently attractive equity internal rates of return across scenarios, especially for off-grid private companies. This confirms its potential to crowd in private capital at scale. The same integrated structure could also be applied in adjacent sectors such as clean cooking, where similar coordination and financing challenges remain unresolved (de Cuadra et al., 2025).

Off-grid systems are not a recent innovation. European countries such as Spain and Portugal have operated isolated systems for decades under centralized and regulated frameworks. Remote islands in both countries have long relied on such models to ensure reliable electricity supply outside the national grid. These cases show that when planning and financing are properly integrated, off-grid electrification can be both sustainable and cost-effective over the long term (European Commission et al., 2023). Similar institutional logic is emerging in sub-Saharan Africa. Madagascar's *Cadre d'Électrification Rurale Intégrée* (Antsa, 2024) and preliminary studies conducted in Rwanda apply the same principles (de Abajo et al., 2020; GCEEP, 2019, 2020). The Ugandan case fits this trajectory and demonstrates how tariff-backed cross-subsidies can underpin national policy.

In Uganda's proposed framework, the integration of cross-subsidies explicitly addresses two critical objectives: equity and financial sustainability. The consumers who contribute to the cross-subsidy pool primarily include urban residential customers and commercial entities whose regulated tariffs slightly exceed their cost of service. Collectively, these revenue streams form a stable, predictable, and transparent financial base for Finance-Co, ensuring its capacity to support long-term electrification investments.

The primary beneficiaries are rural, low-income households residing in remote and underserved regions—particularly in Northern and Northeastern Uganda—where the cost per connection substantially exceeds the national average. These consumers gain earlier and more affordable access to electricity via grid extensions, mini-grids, and standalone systems, all delivered under regulated lifeline tariffs. The

broader socioeconomic benefits of such access are well documented (Lewis and Severnini, 2020). Off-grid solutions, traditionally more expensive for rural consumers, become financially viable and affordable due to permanent viability-gap subsidies from Finance-Co.

The resulting distributional impact of this subsidy structure is inherently progressive. Higher-income urban and commercial consumers contribute proportionally more to the subsidy pool, yet their tariffs remain competitive within regional benchmarks. Industrial consumers stand to benefit directly from the subsidized tariff rate of USD 0.05 per kWh. In the short run, this preferential industrial rate is likely to be advantageous to large manufacturers, as it is likely to support job creation and economic growth. By incorporating transparency into this redistributive scheme, the model fosters political acceptability and mitigates potential resistance from stakeholders.

Overall, explicitly integrating equity considerations enhances both the legitimacy and social relevance of the proposed electrification framework. By transparently redistributing resources from wealthier customer segments and economically prosperous regions to disadvantaged areas and populations, the model explicitly pursues equitable socio-economic outcomes alongside financial sustainability. This institutional design also conditions the financial metrics that follow and links the equity rationale to the system's financial performance.

Three quantitative findings are especially relevant. First, postponing the universal access target to 2040 reduces average distribution CAPEX in 2026 to 2030 from around USD 810 million to almost USD 270 million per year. This two-thirds reduction brings annual investment needs in line with Uganda's current fiscal and institutional capacity. Second, the total funding requirement for Finance-Co over that period falls from USD 3 billion to USD 0.7 billion. Despite this decrease, Finance-Co's equity internal rate of return increases significantly. This is due to the front-loading of equity contributions while tariff-based transfers begin to scale rapidly. Third, off-grid developers also experience stronger financial performance. Early-period equity IRRs approach 30 % by 2031, even as per-connection subsidies decline. This confirms that the integrated financing structure can enhance private returns while lowering the public financing burden. In short, the model is sustainable by design. It requires initial support but establishes an electrification system that becomes self-sustaining over time.

These results carry clear policy implications and offer concrete guidance for government action. They show that Uganda does not need to choose between fiscal responsibility and universal electrification. A centrally financed, phased rollout can deliver both. Turning this potential into real progress depends on four enabling conditions. First, regulatory credibility is critical. The revenue requirement formula and the schedule for tariff indexation must be clearly defined in advance to anchor investor expectations. Second, grant financing in the early years, estimated at around USD 200–600 million between 2026 and 2030, is essential to launch the least-cost electrification program. As the network expands, internal cross-subsidies can progressively replace external support. Third, strong performance from Service-Co is necessary. Reducing losses and improving billing efficiency are key to generating the surplus that finances debt service through Finance-Co. Lastly, policies that stimulate demand, such as support for productive uses, promotion of electric cooking, and access to appliance financing, will accelerate load growth and help shift the sector toward long-term financial self-reliance.

Incentive alignment is also central to the credibility of the model. The financial structure anticipates that private investors respond not only to price signals, but also to how risks are allocated and enforced. Opportunistic behaviors—such as cost inflation, under-maintenance or strategic pressure for renegotiation—are well documented in long-term infrastructure contracts. These risks emerge when downside exposure is transferred to the public sector (Joskow, 2024).

Uganda's framework mitigates this dynamic by embedding automatic feedback between service performance and financial outcomes. Returns to equity are conditional on meeting targets, and access to surpluses is suspended when covenants are breached. This enforcement mechanism is not discretionary. It relies on ex ante rules that tie investor returns to measurable service indicators (Joskow, 2024).

At the same time, institutional features—such as public audits, ring-fenced reserve accounts and narrow, force-majeure-only guarantees—limit expectations of renegotiation and increase the cost of non-compliance (Demirel et al., 2022; Razlog et al., 2020; Nunez et al., 2025; Rybnicek et al., 2020). The centralization of financing in Finance-Co reinforces this by eliminating project-by-project exceptions. From the investor's perspective, this creates a transparent and predictable environment. Efficient operators obtain stable returns. Others face automatic penalties without recourse to political negotiation. In this way, the model aligns behavioral incentives with financial discipline and reduces reliance on ongoing concessional support (Moody's Investor Service, 2023).

Uganda's reform momentum aligns with the launch of Mission 300, a joint initiative by the World Bank and the African Development Bank that aims to channel up to USD 20 billion in concessional finance toward large-scale electrification projects (World Bank, 2024b). Governments that can present bankable, coherent plans with strong political backing will be prioritized for access to this funding. By adopting the Finance-Co and Service-Co structure, finalizing a national electrification plan, and publishing a clear tariff trajectory, Uganda could become an early beneficiary of Mission 300. However, success depends on securing broad consensus among domestic stakeholders, designating a clear leadership authority—ideally MEMD operating through Finance-Co—and ensuring transparent public communication. Any delay risks missing this limited window of concessional financing and weakening the country's ability to attract private investment.

Overall, the Ugandan results reinforce a growing consensus in the literature: universal service obligations in emerging power systems are most credibly financed when distribution investments are consolidated, revenues are pooled and targeted subsidies are delivered through transparent, rule-based mechanisms. By evidencing the magnitude of the fiscal, economic and welfare gains attainable through such an approach, this paper offers regulators and development partners a replicable template for accelerating electrification while safeguarding long-run sector solvency.

7. Conclusion

This study designs and tests an integrated regulatory-financial framework that aligns least-cost electrification strategies with sound financial planning based on cost-reflective revenue, blended capital, and transparent cross-subsidies. The proposed methodology bridges the long-standing gap between techno-economic roadmaps and the financing reality of distribution utilities.

At the core stands Finance-Co, a single public-private vehicle that channels grants, concessional loans, equity, and tariff surpluses to both on- and off-grid projects. Consolidating flows inside one balance sheet lowers transaction costs, secures economies of scale, and yields equity returns high enough to crowd in private capital even for mini-grid and solar home-system providers.

The Uganda case confirms that universal access can be financed sustainably. A 2030 deadline is technically feasible but demands an unprecedented surge of concessional funding; phasing the same investment over a 2040 horizon cuts annual capital needs by two-thirds while raising early-period returns for public and private investors. Policymakers can therefore tune ambition to domestic absorption capacity without sacrificing solvency.

Beyond the country example, the modelling tool offers regulators a practical dashboard to test how tariff levels, equity contributions, debt

terms, and subsidy schedules interact. It produces full financial statements for each entity, enforces standard ratio constraints, and iterates until the system balances, giving decision-makers an auditable basis to negotiate terms with funders and operators on a transparent basis.

The key insight is clear. Universal access is not only a development objective. It is a viable investment proposition—when planned, financed, and regulated as a single system. This framework provides the technical and financial architecture to turn electrification targets into bankable programs.

CRediT authorship contribution statement

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

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Appendix A. Appendix

The complete financial statements for the entities defined under the proposed sector structure are included in the remaining pages of this appendix. These statements cover: (i) Finance-Co, the centralized financial intermediary; (ii) the unified group of private off-grid companies, comprising both mini-grid and standalone solar system developers; and (iii) Umeme, up to the end of its concession in 2025, followed by its successor, the public–private Service-Co.

A.1. Finance-Co financial statements and key ratios

Table 5
P&L and Balance Sheet for Finance-Co during the 2026–2040 period. Source: Authors' calculations (compiled in "Summary of Tables" worksheet; derived from "FinanceCo" worksheet in base-case replication model).

		2026	2027	2028	2029	2030	2031	2036	2040
Profit and loss (P&L) statement USD million	Service-Co surplus to Finance-Co	1.0	101.2	189.7	320.6	502.7	697.3	1826.5	3572.6
	Subsidies to off-grid companies	−56.4	−89.1	−120.1	−149.5	−177.6	−185.0	−204.9	−214.9
	EBITDA	**44.2**	**118.6**	**185.1**	**300.1**	**474.4**	**512.3**	**1621.5**	**3357.8**
	D&A	−61.9	−85.8	−111.8	−140.8	−174.3	−180.0	−211.2	−240.0
	Financial Expense	−0.5	−3.0	−11.0	−23.0	−34.5	−40.0	−32.0	−4.0
	EBT	**−18.2**	**29.8**	**62.3**	**136.3**	**265.6**	**292.3**	**1378.3**	**3113.8**
	% Tax rate	30 %	30 %	30 %	30 %	30 %	30 %	30 %	30 %
	Taxes	–	–	–	–	–	−50.4	−413.5	−934.1
	Net Income	**−18.2**	**29.8**	**62.3**	**136.3**	**265.6**	**241.9**	**964.8**	**2179.6**
Balance Sheet USD million	**Non-current assets**	**497.7**	**1010.2**	**1547.4**	**2131.7**	**2796.1**	**2757.4**	**2545.3**	**2350.9**
	PP&E	497.7	1010.2	1547.4	2131.7	2796.1	2757.4	2545.3	2350.9
	Current assets	**34.6**	**45.3**	**54.8**	**77.9**	**79.7**	**360.3**	**3181.0**	**8546.9**
	Cash and equivalents	34.4	32.8	31.5	38.3	17.7	274.3	2955.8	8106.5
	Trade receivables	0.1	12.5	23.4	39.5	62.0	86.0	225.2	440.5
	Total Assets	**532.2**	**1055.5**	**1602.3**	**2209.5**	**2875.8**	**3117.7**	**5726.2**	**10897.8**
	Total Shareholders' Equity	**181.8**	**411.6**	**473.9**	**610.2**	**875.8**	**1117.7**	**4226.2**	**10897.8**
	Share capital & treasury shares	200.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0
	Retained earnings	−18.2	29.8	62.3	136.3	265.6	241.9	964.8	2179.6
	Reserves	–	−18.2	11.6	73.9	210.2	475.8	2861.4	8318.2
	Long term liabilities	**350.4**	**643.9**	**1128.4**	**1599.3**	**2000.0**	**2000.0**	**1500.0**	**–**
	Grants	300.4	393.9	278.4	149.3	–	–	–	–
	LT financial liabilities	50.0	250.0	850.0	1450.0	2000.0	2000.0	1500.0	–
	Total Liabilities	**532.2**	**1055.5**	**1602.3**	**2209.5**	**2875.8**	**3117.7**	**5726.2**	**10897.8**
	Check	–	–	–	–	–	–	–	–

Table 6
Cash Flow Statement and key financial ratios for Finance-Co during the 2026–2040 period. Source: Authors' calculations (compiled in "Summary of Tables" worksheet; derived from "FinanceCo" worksheet in base-case replication model).

		2026	2027	2028	2029	2030	2031	2036	2040
Cash Flow Statement USD million	EBITDA (ex-Grants)	−55.4	12.1	69.6	171.0	325.1	512.3	1621.5	3357.8
	- Taxes	–	–	–	–	–	−50.4	−413.5	−934.1
	+/− Change in WC	−0.1	−12.4	−10.9	−16.1	−22.5	−24.0	−32.5	−66.1
	Operating Cash Flow	**−55.5**	**−0.3**	**58.7**	**154.9**	**302.7**	**437.9**	**1175.5**	**2357.6**
	Capex	−559.6	−598.3	−649.1	−725.0	−838.8	−141.3	−166.2	−189.2
	Cash Flow from Assets	**−615.1**	**−598.6**	**−590.4**	**−570.1**	**−536.1**	**296.6**	**1009.3**	**2168.4**
	Financial Income	–	–	–	–	–	–	–	–
	Financial Expense	−0.5	−3.0	−11.0	−23.0	−34.5	−40.0	−32.0	−4.0
	Debt repayment	–	–	–	–	–	–	−200.0	−400.0
	Debt increase	50.0	200.0	600.0	600.0	550.0	–	–	–
	Grants/Sub-debt financing	400.0	200.0	–	–	–	–	–	–
	Dividends	–	–	–	–	–	–	–	–
	+/− Capital Increase/Reduction	200.0	200.0	–	–	–	–	–	–
	Financing Cash Flow	**649.5**	**597.0**	**589.0**	**577.0**	**515.5**	**−40.0**	**−232.0**	**−404.0**
	Cash BoP	–	34.4	32.8	31.5	38.3	17.7	2178.5	6342.1
	Cash movement	34.4	−1.6	−1.4	6.9	−20.6	256.6	777.3	1764.4
	Cash EoP	34.4	32.8	31.5	38.3	17.7	274.3	2955.8	8106.5
Financial Ratios	DSCR (x)	88.5	39.5	16.8	13.0	13.8	12.8	7.0	8.3
	Equity IRR (%)	–	–	–	–	–	17.7 %	39.5 %	38.1 %
	Total Debt / EBITDA (x)	7.9	5.4	6.1	5.3	4.2	3.9	0.9	–
	ROE (%)	−20.0 %	10.0 %	14.1 %	25.1 %	35.7 %	24.3 %	25.8 %	22.2 %
	Total Debt / PP&E (%)	70.4 %	63.7 %	72.9 %	75.0 %	71.5 %	72.5 %	58.9 %	0.0 %

Notes. All figures in USD million. One decimal in all columns. Minus sign denotes negative values. Entries with absolute value below 0.1 appear as <0.1 and as - < 0.1 when negative. A dash indicates not available or not applicable. Totals may not sum because of rounding. Decimal point used and a leading zero appears for values between −1.0 and 1.0. Years are calendar years.

A.2. The aggregated off-grid private companies financial statements and key ratios

Table 7
P&L and Balance Sheet for the aggregated off-grid private companies during the 2021–2040 period. Source: Authors' calculations (compiled in "Summary of Tables" worksheet; derived from aggregated off-grid providers' financial model in base-case scenario).

		2021	2022	2026	2027	2028	2029	2030	2031	2036	2040
Profit and loss (P&L) statement USD million	Regulated Tariff Income	0.7	1.2	13.0	25.2	37.6	49.9	62.4	70.4	89.6	113.6
	Subsidies to off-grid companies	2.0	5.8	56.4	89.1	120.1	149.5	177.6	185.0	204.9	214.9
	Distribution costs (O&M)	−0.5	−1.8	−19.5	−36.5	−54.0	−72.1	−90.8	−102.6	−128.9	−158.3
	Administrative Expenses (Customers/Billing)	- < 0.1	−0.1	−0.6	−1.0	−1.5	−2.0	−2.5	−2.8	−3.7	−4.6
	EBITDA	**2.1**	**5.1**	**49.2**	**76.8**	**102.2**	**125.4**	**146.7**	**149.9**	**162.0**	**165.5**
	D&A	−1.1	−2.8	−28.5	−45.5	−62.1	−78.3	−94.2	−97.4	−111.5	−113.8
	Financial Expense	–	–	−2.2	−7.4	−12.4	−16.0	−18.4	−18.8	−12.4	−2.8
	EBT	**1.0**	**2.3**	**18.5**	**24.0**	**27.7**	**31.1**	**34.1**	**33.8**	**38.1**	**48.9**
	% Tax rate	30 %	30 %	30 %	30 %	30 %	30 %	30 %	30 %	30 %	30 %
	Taxes	–	–	–	–	–	–	–	–	–	–
	Net Income	**1.0**	**2.3**	**18.5**	**24.0**	**27.7**	**31.1**	**34.1**	**33.8**	**38.1**	**48.9**
Balance Sheet USD million	**Non-current assets**	**8.3**	**19.1**	**172.4**	**261.3**	**334.6**	**392.7**	**437.2**	**438.2**	**421.0**	**430.8**
	PP&E	8.3	19.1	172.4	261.3	334.6	392.7	437.2	438.2	421.0	430.8
	Current assets	**87.5**	**78.6**	**10.6**	**17.5**	**17.9**	**26.0**	**21.6**	**29.5**	**50.0**	**59.2**
	Cash and equivalents	87.4	78.3	7.4	11.4	8.8	13.9	6.5	12.4	28.3	32.2
	Trade receivables	0.1	0.1	1.6	3.1	4.6	6.2	7.7	8.7	11.0	14.0
	Inventories	<0.1	0.1	1.6	3.0	4.4	5.9	7.5	8.4	10.6	13.0
	Total Assets	**95.8**	**97.8**	**183.0**	**278.7**	**352.4**	**418.7**	**458.9**	**467.7**	**471.0**	**490.0**
	Total Shareholders' Equity	**95.7**	**97.5**	**124.8**	**142.7**	**163.6**	**186.9**	**203.9**	**220.8**	**309.8**	**444.0**
	Share capital & treasury shares	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0
	Retained earnings	0.7	1.7	13.9	18.0	20.8	23.3	17.0	16.9	19.1	36.7
	Reserves	–	0.7	15.9	29.8	47.7	68.6	91.9	108.9	195.8	312.3
	Long term liabilities	**–**	**–**	**55.0**	**130.0**	**180.0**	**220.0**	**240.0**	**230.0**	**140.0**	**20.0**
	LT financial liabilities	–	–	55.0	130.0	180.0	220.0	240.0	230.0	140.0	20.0
	Short term liabilities	**0.1**	**0.3**	**3.2**	**6.0**	**8.9**	**11.8**	**14.9**	**16.9**	**21.2**	**26.0**
	Trade payables	0.1	0.3	3.2	6.0	8.9	11.8	14.9	16.9	21.2	26.0
	Total Liabilities	**95.8**	**97.8**	**183.0**	**278.7**	**352.4**	**418.7**	**458.9**	**467.7**	**471.0**	**490.0**
	Check	–	–	–	–	–	–	–	–	–	–

Table 8
Cash Flow Statement and key financial ratios for the aggregated off-grid private companies during the 2021–2040 period. Source: Authors' calculations (compiled in "Summary of Tables" worksheet; derived from aggregated off-grid providers' financial model in base-case scenario).

		2021	2022	2026	2027	2028	2029	2030	2031	2036	2040
Cash Flow Statement USD million	EBITDA (ex-Grants)	2.1	5.1	49.2	76.8	102.2	125.4	146.7	149.9	162.0	165.5
	- Taxes	–	–	–	–	–	–	–	–	–	–
	+/− Change in WC	- < 0.1	<0.1	−0.1	−0.1	−0.1	- < 0.1	<0.1	- < 0.1	−0.1	−0.2
	Operating Cash Flow	**2.1**	**5.1**	**49.2**	**76.7**	**102.1**	**125.4**	**146.7**	**149.9**	**161.9**	**165.3**
	Capex	−9.4	−13.6	−133.6	−134.3	−135.4	−136.5	−138.7	−98.3	−111.9	−117.8
	Cash Flow from Assets	**−7.3**	**−8.5**	**−84.4**	**−57.6**	**−33.2**	**−11.1**	**8.0**	**51.6**	**50.1**	**47.6**
	Financial Income	–	–	–	–	–	–	–	–	–	–
	Financial Expense	–	–	−2.2	−7.4	−12.4	−16.0	−18.4	−18.8	−12.4	−2.8
	Debt repayment	–	–	−5.0	−5.0	−5.0	−10.0	−10.0	−10.0	−30.0	−30.0
	Debt increase	–	–	60.0	80.0	55.0	50.0	30.0	–	–	–
	Grants/Sub-debt financing	–	–	–	–	–	–	–	–	–	–
	Dividends	−0.2	−0.6	−4.6	−6.0	−6.9	−7.8	−17.0	−16.9	−19.1	−12.2
	+/− Capital Increase/Reduction	95.0	–	–	–	–	–	–	–	–	–
	Financing Cash Flow	**94.8**	**−0.6**	**48.2**	**61.6**	**30.7**	**16.2**	**−15.4**	**−45.7**	**−61.5**	**−45.0**
	Cash BoP	–	87.4	43.6	7.4	11.4	8.8	13.9	6.5	39.8	29.7
	Cash movement	87.4	−9.1	−36.2	4.0	−2.6	5.1	−7.5	6.0	−11.4	2.5
	Cash EoP	87.4	78.3	7.4	11.4	8.8	13.9	6.5	12.4	28.3	32.2
Financial Ratios	DSCR (x)	nr	nr	6.8	6.2	5.9	4.8	5.2	5.2	3.8	5.0
	Equity IRR (%)	–	–	–	–	–	–	–	20.7 %	17.1 %	15.3 %
	Total Debt / EBITDA (x)	–	–	1.1	1.7	1.8	1.8	1.6	1.5	0.9	0.1
	ROE (%)	1.0 %	2.4 %	15.7 %	17.9 %	18.1 %	17.8 %	17.4 %	15.9 %	12.7 %	11.5 %
	Total Debt / PP&E (%)	–	–	31.9 %	49.8 %	53.8 %	56.0 %	54.9 %	52.5 %	33.3 %	4.6 %

Notes. All figures in USD million. One decimal in all columns. Minus sign denotes negative values. Entries with absolute value below 0.1 appear as <0.1 and as - < 0.1 when negative. A dash indicates not available or not applicable. Totals may not sum because of rounding. Decimal point used and a leading zero appears for values between −1.0 and 1.0. Years are calendar years.

A.3. Umeme and after 2025, Service-Co financial statements and key ratios

Table 9
P&L and Balance Sheet for Umeme and after 2025, Service-Co during the 2021–2040 period. Source: Authors' calculations (compiled in "Summary of Tables" worksheet; derived from distribution utility model – Umeme/Service-Co – in base-case scenario).

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2036	2040
Profit and loss (P&L) statement USD million	Regulated Tariff Income	432.7	437.5	471.4	507.8	516.0	590.9	782.7	1023.2	1333.1	1728.3	4027.3	6796.1
	Upstream Cost of Energy	−297.5	−287.4	−307.2	−330.1	−358.0	−417.1	−503.6	−597.7	−711.8	−849.8	−1683.4	−2598.2
	Distribution costs (O&M)	−12.0	−11.7	−11.7	−11.7	−16.2	−26.0	−43.3	−68.3	−95.8	−127.0	−179.1	−209.0
	Service-Co surplus to Finance-Co	–	–	–	–	–	−54.5	−101.2	−189.7	−320.6	−502.7	−1826.5	−3572.6
	Provisions for bad debt	−2.2	−2.2	−2.4	−2.5	−2.6	−3.0	−3.9	−5.1	−6.7	−8.6	−20.1	−34.0
	Administrative Expenses (Customers/Billing)	−48.3	−50.3	−53.5	−56.0	−58.4	−79.2	−113.9	−145.5	−180.5	−220.3	−309.9	−372.8
	EBITDA	**72.7**	**85.9**	**96.6**	**107.4**	**80.8**	**11.2**	**16.8**	**16.9**	**17.7**	**19.8**	**8.3**	**9.5**
	D&A	−39.5	−39.5	−39.5	−39.5	−39.5	–	–	–	–	–	–	–
	Financial Expense	−7.0	−5.5	−4.1	−2.7	−1.0	–	–	–	–	–	–	–
	EBT	**26.2**	**40.8**	**53.0**	**65.3**	**40.3**	**11.2**	**16.8**	**16.9**	**17.7**	**19.8**	**8.3**	**9.5**
	% Tax rate	30 %	30 %	30 %	30 %	30 %	30 %	30 %	30 %	30 %	30 %	30 %	30 %
	Taxes	−7.9	−12.2	−15.9	−19.6	−12.1	−3.4	−5.0	−5.1	−5.3	−5.9	−2.5	−2.8
	Net Income	**18.4**	**28.6**	**37.1**	**45.7**	**28.2**	**7.8**	**11.8**	**11.8**	**12.4**	**13.9**	**5.8**	**6.6**
Balance Sheet USD million	**Non-current assets**	**340.2**	**340.2**	**340.1**	**340.0**	**340.0**	**340.0**	**340.0**	**340.0**	**340.0**	**340.0**	**340.0**	**340.0**
	Intangibles	340.2	340.2	340.1	340.0	340.0	340.0	340.0	340.0	340.0	340.0	340.0	340.0
	Current assets	**167.9**	**162.6**	**166.4**	**175.1**	**170.3**	**198.4**	**235.0**	**280.9**	**338.1**	**409.7**	**805.2**	**1272.7**
	Cash and equivalents	106.9	102.0	101.5	105.3	97.1	109.0	117.4	126.5	135.8	146.1	170.9	189.8
	Trade receivables	35.6	36.0	38.7	41.7	42.4	48.6	64.3	84.1	109.6	142.1	331.0	558.6
	Inventories	25.4	24.6	26.2	28.1	30.8	40.9	53.3	70.3	92.7	121.6	303.2	524.4
	Total Assets	**508.2**	**502.7**	**506.5**	**515.1**	**510.3**	**538.4**	**574.9**	**620.9**	**678.1**	**749.7**	**1145.1**	**1612.7**
	Total Shareholders' Equity	**379.0**	**393.3**	**411.8**	**434.7**	**448.8**	**456.6**	**468.4**	**480.2**	**492.6**	**506.5**	**538.7**	**564.0**
	Retained earnings	9.2	14.3	18.5	22.8	14.1	7.8	11.8	11.8	12.4	13.9	5.8	6.6

(*continued on next page*)

Table 9 (*continued*)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2036	2040
	Reserves	369.8	379.0	393.3	411.8	434.7	448.8	456.6	468.4	480.2	492.6	532.9	557.4
	Long term liabilities	**78.3**	**60.3**	**42.3**	**24.3**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**
	Grants	–	–	–	–	–	–	–	–	–	–	–	–
	LT financial liabilities	78.3	60.3	42.3	24.3	–	–	–	–	–	–	–	–
	Short term liabilities	**50.9**	**49.2**	**52.4**	**56.2**	**61.5**	**81.8**	**106.5**	**140.7**	**185.4**	**243.2**	**606.4**	**1048.7**
	Trade payables	50.9	49.2	52.4	56.2	61.5	81.8	106.5	140.7	185.4	243.2	606.4	1048.7
	Total Liabilities	**508.2**	**502.7**	**506.5**	**515.1**	**510.3**	**538.4**	**574.9**	**620.9**	**678.1**	**749.7**	**1145.1**	**1612.7**
	Check	–	–	–	–	–	–	–	–	–	–	–	–

Table 10
Cash Flow Statement and key financial ratios for Umeme and after 2025, Service-Co during the 2021–2040 period. Source: Authors' calculations (compiled in "Summary of Tables" worksheet; derived from distribution utility model – Umeme/Service-Co – in base-case scenario).

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2036	2040
Cash Flow Statement USD million	EBITDA (ex-Grants)	72.7	85.9	96.6	107.4	80.8	11.2	16.8	16.9	17.7	19.8	8.3	9.5
	- Taxes	−7.9	−12.2	−15.9	−19.6	−12.1	−3.4	−5.0	−5.1	−5.3	−5.9	−2.5	−2.8
	+/− Change in WC	17.8	−1.2	−1.2	−1.1	2.0	4.0	−3.4	−2.7	−3.1	−3.6	−4.2	−1.8
	Operating Cash Flow	**82.6**	**72.4**	**79.5**	**86.7**	**70.7**	**11.8**	**8.4**	**9.1**	**9.3**	**10.3**	**1.6**	**4.9**
	Capex	−39.5	−39.5	−39.5	−39.5	−39.5	–	–	–	–	–	–	–
	Cash Flow from Assets	**43.2**	**32.9**	**40.1**	**47.3**	**31.2**	**11.8**	**8.4**	**9.1**	**9.3**	**10.3**	**1.6**	**4.9**
	Financial Income	–	–	–	–	–	–	–	–	–	–	–	–
	Financial Expense	−7.0	−5.5	−4.1	−2.7	−1.0	–	–	–	–	–	–	–
	Debt repayment	−18.0	−18.0	−18.0	−18.0	−24.3	–	–	–	–	–	–	–
	Debt increase	–	–	–	–	–	–	–	–	–	–	–	–
	Grants/Sub-debt financing	–	–	–	–	–	–	–	–	–	–	–	–
	Dividends	−9.2	−14.3	−18.5	−22.8	−14.1	–	–	–	–	–	–	–
	+/− Capital Increase/ Reduction	–	–	–	–	–	–	–	–	–	–	–	–
	Financing Cash Flow	**−34.2**	**−37.8**	**−40.6**	**−43.5**	**−39.4**	**–**	**–**	**–**	**–**	**–**	**–**	**–**
	Cash BoP	97.9	106.9	102.0	101.5	105.3	97.1	109.0	117.4	126.5	135.8	169.3	184.9
	Cash movement	9.0	−4.9	−0.6	3.8	−8.1	11.8	8.4	9.1	9.3	10.3	1.6	4.9
	Cash EoP	106.9	102.0	101.5	105.3	97.1	109.0	117.4	126.5	135.8	146.1	170.9	189.8
Financial Ratios	DSCR (x)	2.9	3.6	4.4	5.2	3.2	nr	nr	nr	nr	nr	nr	nr
	Equity IRR (%)	–	–	–	–	–	–	–	–	–	–	–	–
	Total Debt / EBITDA (x)	1.1	0.7	0.4	0.2	–	–	–	–	–	–	–	–
	ROE (%)	4.8 %	7.4 %	9.2 %	10.8 %	6.4 %	1.7 %	2.5 %	2.5 %	2.6 %	2.8 %	1.1 %	1.2 %
	Total Debt / PP&E (%)	23.0 %	17.7 %	12.4 %	7.1 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %

Notes. All figures in USD million. One decimal in all columns. Minus sign denotes negative values. Entries with absolute value below 0.1 appear as <0.1 and as - < 0.1 when negative. A dash indicates not available or not applicable. Totals may not sum because of rounding. Decimal point used and a leading zero appears for values between −1.0 and 1.0. Years are calendar years.

Appendix B. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.eneco.2025.109033.

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