Business model innovations for utility and mini-grid integration: Insights from the Utilities 2.0 initiative in Uganda

Energy Insight

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1 Introduction: the opportunity for a utility revolution

The historical context from which many African utilities have emerged has left a challenging legacy regarding the provision of energy service delivery to all. As rural electrification receives growing attention, a wave of decentralised renewable energy (DRE) technologies and business models are changing the energy service delivery landscape.[1] Given the variety of electricity delivery platforms now available and the wide range of customer needs, electrification approaches that mobilise all these capabilities in an integrated framework may offer solutions to delivering access while unlocking economic growth and social impact. African utilities are thus poised on the cusp of a major opportunity to extend access while improving financial sustainability through integration.

Launched by Power for All and funded by the Rockefeller Foundation, Utilities 2.0 is a coalition of partners testing the premise that a transformational configuration of technologies and market actors can achieve faster, cheaper, and more universal connections than a grid-only approach. Working with a consortium of centralised and decentralised companies—including Umeme (distribution utility), Energrow (appliance finance), Equatorial Power (mini-grid), and East African Power (micro industrial appliances)—Power for All is modelling viable commercial partnerships based on real-world costs, revenues, ownership and operational approaches, and policy constraints.

While the concept of integrated energy is sparking imaginations and inspiring partnerships around the world, the commercial viability of cooperative electrification efforts has yet to be proven. As with any new business concept, business models that demonstrate profit potential are a necessary precursor to realising the potential social impacts—in this case, accelerated connections, increased productive use, and improved grid performance. To this end, Power for All's EEG Insight answers the question: what relative benefits to customers, the utility, and developers can be gained through novel partnerships to reduce connections cost, capital requirements to deliver access, and grow demand and revenue?

This Energy Insight focuses specifically on the opportunities for distribution utilities and mini-grid developers to collaborate. The brief identifies the financial drivers that influence the cost of service for both utilities and mini-grid developers, then describes three business model innovations as compared to business-as-usual grid extension strategies and provides first approximation estimates of their profitability (either in the form of savings or increased revenue generation). These three concepts are: the Mini-Grid Led Integration Model; the Flexible Asset Ownership Model; and the Utility Led Integration Model. Finally, the brief also reflects on the critical success factors necessary to encourage such partnerships between the utility and mini-grid developers to support delivery of faster, cheaper, and more universal electricity connections.

2 Three critical cost drivers for electricity service providers

A complex mix of capital expenditures (capex) and operating expenditures (opex), and the cost of capital supporting those investments, drives the economics of energy service provision, for centralised and decentralised providers alike. Capex includes upfront "hard costs"—like capital investments in solar generation assets, batteries, and distribution network equipment—as well as "soft costs" like project design, licensing, and logistics. Opex includes expenses like maintenance, staffing, and insurance that support ongoing operations. The cost of capital is the return that investors expect on the debt and equity put into the project.

Companies operating in the electricity sector face vastly differing borrowing rates and costs of capital depending the risk inherent in their business models and their track records of performance. A regulated utility with an established customer base that is able to recover capital investments through

[1] More than 40% of sub-Saharan African countries now have official rural electrification targets and at least a third have specific DRE targets or plans (Power for All, 2017). From January to June 2019, over four million quality-certified solar lanterns and solar home systems were sold on the continent (GOGLA, 2019) and over 4,000 mini-grids are in various stages of planning and development (ESMAP, 2019).

tariffs has a much different risk profile than a start-up mini-grid developer trying to build a customer base from scratch. While established utilities can tap longer-term, infrastructure-priced debt, mini-grid developers are typically reliant on equity capital that is seeking higher investment returns. By one estimate, 83% of the total capital raised by private mini-grid developer between 2010 and 2018 was equity, an indication that the sector faces very high costs of capital (Wood Mackenzie, Energy 4 Impact, 2019). The alternative commercial partnerships modelled for this EEG Insight aim to identify strategies for reducing capex for firms facing higher costs of capital—while still allowing them to utilize their comparative advantages—in order to more fully marshal the potential of the DRE sector, meet the electrification ambitions of governments, and minimize the cost to the consumer.

Cost drivers of universal electrification in Uganda

The Government of Uganda has set targets to connect two million new customers by 2025 and to achieve universal access (over five million new connections) by 2030. Achieving five million new connections in five years will require doubling or tripling the pace achieved with Umeme's traditional distribution approaches (Uganda Vision, 2040). As the majority of the unconnected are in peri-urban or rural areas, the cost to meet targets could be US $5–US $10 billion or more—beyond the capacity of many energy-poor countries[2] (World Bank, 2020).[3] Moreover, the newly connected often use little power and are served at the lowest tariff (e.g. a 'life-line' rate),[4] creating a monumental profitability challenge and financial risk for countries wanting to create a sustainable electricity system.

3 Motivations for commercial partnership between utilities and mini-grid developers

There are comparative advantages that both the utility and the mini-grid developer can offer. For instance, mini-grid developers often have a deep understanding of customers and a focus on customer experience, service, and satisfaction. Mini-grid developers now regularly create and grow demand as part of their business model (Smart Power India, 2017). In a country like Uganda, stimulating electricity demand within the customer base is critically important. The country has leveraged its access to low-cost hydropower to develop new supply that is already [more than double the current peak demand. Demand growth is imperative to the power sector's long-term financial sustainability.

Mini-grid developers, however, often operate at a relatively modest scale—the three largest private mini-grid developers in Africa[5] have together installed less than 250 mini-grids over only eight countries, serving roughly [34,000 customers in total. (ESMAP, 2019). By contract, Umeme serves 1,500,000 customers](Umeme,2019). Mini-grid developers are usually venture-backed private enterprises, with comparatively high capital costs, little scale in their operations. They are further constrained by the lack of policy and regulation governing the sector, including licensing processes and grid-arrival compensation mechanisms (Power for All, 2019). Conversely, centralised distribution utilities often have far larger-scale, tightly regulated operations, and comparatively low operating cost (Umeme, 2019). They also often have comparatively lower-cost capital.[6]

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[2] Power for All analysis using Umeme two-pole connection cost US $1,485 per connection multiplied by number of connections to reach universal access by 2040 in Uganda (5.3 million connections) results in a cost of US $7.8 billion using a business-as-usual grid extension.

[3] The World Bank has developed a Draft National Electrification Strategy with the Ministry of Energy and Minerals Development in 2020. This study models a mix of technologies required to achieve universal access in Uganda under two scenarios namely; Base Case A – Grid Extension with an off grid boundary of 15km and Base Case B- Grid Extension using REA projects and all other zones marked as off-grid, which is a mix of grid extension, densification, mini-grids and solar home systems to reach universal access, indicating that the total cost to reach electrification using a range of technologies is estimated at US $5.2 billion.

[4] The Umeme life-line tariff for low usage customers is as follows: the first 15 kWh is at a tariff of US $0.07/kWh; above 15 kWh, the tariff is US $0.20/kWh (Umeme, 2020).

[5] According to the AMDA (2020) Benchmarking Mini-Grids Report and ESMAP (2019) report.

[6] Because of its financial strength and balance sheet, Umeme Ltd can attract capital at much lower costs than the mini-grid players. Umeme can lend money at a rate as low as 7.3% (Umeme, 2019).

Finally, while some countries have achieved significant electrification with grid-based approaches, challenges such as high system losses and low-usage and/or non-paying customers stress a utility's ability to remain financially sustainable and maintain a high quality of service (Power for All, 2019). In fact, across sub-Saharan Africa, utility deficits average US $0.12 per kWh and can range as high as US $0.49 per kWh, generating quasi-fiscal deficits averaging 1.5% of GDP. In three countries, these deficits top 5% of GDP (World Bank, 2016). The constant downward pressure on tariffs from the regulator and public further act as financial drivers for the distribution utility. Mini-grids, however, can be modular, flexible systems that allow for reduced power losses and increased reliability. In fact, studies find that mini-grid developers provide service that consistently exceeds that of the main grid (ESMAP, 2019) and can thus be instrumental to improving quality of service. As such, for both mini-grids and the utility there are opportunities to address cost drivers through partnership or integrated business models.

4 A framework to assess business model impacts

Given these three key cost drivers—and the comparative advantages of centralised and decentralised business—partnerships that can leverage comparative strengths and reduce costs to both parties and the end user while growing demand and revenue. Much of the existing analysis focuses on barriers to scaling mini-grids and how to reduce capital investments through falling technology costs and the cost reductions that result from economies of scale and standardisation (RMI, 2018; NREL, 2018; World Bank, 2019). In this brief, however, we demonstrate what cost savings could look like through integrated approaches involving both the utility and DRE players. The research question is: what relative benefits to customers, the utility, and developers can be gained through novel partnership approaches to addressing cost drivers?

Most mini-grid business models include capital and operating costs of generation and distribution, making comparison of connection costs between mini-grids and distribution utilities difficult. Moreover, many mini-grid developers include productive use assets (assets that enable owners to generate profits and cash flow) or other demand stimulation investments in capex and opex, further complicating comparison. For this reason we use an income statement or profit and loss based framework to review and assess all expenditures which are separated by their respective segment of the value chain: generation, (transmission) distribution and connection, and demand stimulation.[7] To compare the associated costs of mini-grids and utilities, we collect real world capex and opex estimates for the distribution utility (Umeme Annual Report, 2019) and a local mini-grid company in Uganda.

With this profit and loss framework we are able to evaluate how expenses are managed across the models and to identify areas of efficiency across the value chain. We then explore the impact of three different (but related) models for reducing the key drivers of power and connection costs—capital investment, operating expenses, and the cost of capital—to understand how they impact power delivery costs in aggregate. We start from the sector status quo: an independent, distributed mini-grid micro-utility with high soft costs (such as project development costs, licensing costs, and repeated system customisations), scarce and expensive capital, and low energy demand growth, where the utility may be viewed as a threat. We move towards different models of shared ownership between the two, with aligned incentives, grid-compatible and integration-ready systems, shared branding, focused demand stimulation, and lower capital costs.

At its core, this is an exercise in breaking down the component parts of the standalone Independent Power Producer (IPP) mini-grid business model, adding in the utility and wider cast of players in the energy service sector and reassembling that ecosystem in a way that optimises strengths. Each mini-grid and utility integration model explored is designed to deliver the same electrification plan using different strategies: that is, providing electricity to a peri-urban non-connected

[7] In Uganda, generation, transmission, and distribution are each managed and funded separately, as opposed to vertically integrated utilities.

community, with grid integration following in two years.[8] As metrics of comparisons, we present power supply costs (represented as the levelised cost of electricity (LCOE)) and the connection cost.

A sensitivity analysis was conducted to understand the impact of assumed discount rates and rates of return. A full explanation of methods and formulae can be found in Annex 1.

5 Business models innovation: opportunities to accelerate access profitably

The three models scale along a spectrum based on flexibility, increased productive use, and shifts in the allocation of capex, opex, and overall risk to deliver the access needed. In each case, the utility invests capital, operational, or implementation support in exchange for commercial and social gains by developing a profitable load centre for eventual interconnection. These business model approaches are:[9]

1. the Mini-Grid Led Integration Model;
2. the Flexible Asset Ownership; and
3. the Utility Led Integration Model.

Across all three models, some core responsibilities do not change: the mini-grid operator is the body that interacts with customers, manages billing, and markets appliances or other services to boost demand; and

- the utility builds and maintains the distribution system to a standard that would allow future integration with the grid.

What changes between the different models is who owns and who operates the electricity generation assets, how they are financed, and whether they are fixed or mobile assets. For each approach, we describe the conceptual model, describe the rationale and each stakeholder's role, and lay out the likely regulatory requirements for the Ugandan context. In the results section to follow, we explain the potential cost impacts from our preliminary analysis.

Across each integrated business model, the distribution utility will benefit through:

- **Profitable customers**: upon grid integration, the utility receives a more profitable customer from a consumption and revenue point (that is, consumption double that of average domestic customers);[10]
- **Lower risk:** currently a large and growing share of utility customers are low- or no-profit, but the utility is obligated to serve them. Up-front visibility to usage and profitability would significantly reduce this risk.
- Accelerated demand growth: it would normally take the utility four years to organically double customer demand once connected via grid extension. Utilities 2.0 aims to increase customer demand by six times the current average domestic consumption level in one year (Umeme, 2020);11
- New revenue streams: partnering with DRE companies through an integrated energy approach can increase the utility's revenue through the services such as building the distribution network or providing a billing and CRM platform. The utility will be paid and makes a profit on the provision of these services before the grid arrives;
- Commercial business opportunities, diversification, and innovation: these novel business models present an opportunity for the utility to diversify its investment into renewable

[8] The Utilities 2.0 demonstration community in Uganda is an unelectrified village of approximately 400 households approximately 3 km from the existing Umeme grid network with relatively modest commercial activity, no heavy-usage 'anchor load(s)', and an expected household usage of ~10 kWh per month based on usage in similar electrified communities. This is intentionally representative of communities Umeme typically struggles to serve. Based on demand simulation and economic growth projections for this community, it is estimated that the generation system supply capacity will be exceeded by the demand of the site within two years. Hence, this establishes a roughly two-year timeframe for grid integration.
[9] These alternative business models are yet to be tested and their proposed benefits to the utility, customers, and developers are yet to be confirmed. The Mini-Grid Led Integration Model is currently part of the Utilities 2.0 pilot and outcomes from the field will help validate these analysis findings. Further investigation is needed to assess benefits at scale.
[10] Umeme's domestic grid connected customers consume an average of 45 kWh per month and low-demand rural customers consume 17 kwh per month (Umeme, 2020).
[11] Customers initially consume 4 kWh–10 kWh per month when connected to the grid. It takes Umeme four years to achieve demand growth and a consumption of 17 kWh–40 kWh per month through natural growth at the site, with no customer development or demand stimulation.

energy. This model further enables the utility to innovate12 by considering how to make storage part of the distribution network to increase and strengthen the network reliability; and

- Achieving government access targets: this integrated energy approach further enables the utility to support the government's access targets by lowering the connections cost by between 15% and 35% across the three alternative business models and increasing customer demand through demand stimulation.[13] It further supports the government to continue attracting investment to the electricity sector and strengthens its distribution component of the energy value chain.

Mini-Grid Led Integration Model

In this model, currently part of the Utilities 2.0 pilot in Uganda, the mini-grid developer designs, purchases, and operates the mini-grid, while the utility builds the distribution network. The utility co-brands service offerings and technical support, while the mini-grid developer focuses on customer development. This is a low-risk way for the utility and mini-grid developer to trial partnership in the marketplace by leveraging the utility's strengths in lowering the cost of service for the mini-grid and establishing the impact of mini-grid led demand stimulation to the utility.

Rationale

- The utility can meet the increasing pressure for access and equity that it is not currently purpose-built to achieve.
- The utility can explore new revenue streams, including distribution network building outside of concession areas.
- The mini-grid developer can demonstrate its value-addition to customer development, demand growth, quality of service, and increased pace of connections.
- There is a reduced cost per connection, enabling more connections at reduced financial risk to all development partners and at a faster pace for customers.
- Demand growth potential, if realised by decentralised initiatives, benefits all stakeholders by absorbing the country's available electricity supply.

Roles and responsibilities

- Mini-grid developer: designs, purchases, installs, and maintains the distributed generation assets (e.g. solar; battery storage); connects households at utility standard (see annex for definitions)[14] using the utility meter, customer management, and billing system; and focuses on demand stimulation by proactively engaging customers, providing or marketing demand-generating assets. Also receives any donor or national subsidy for connections.[15]
- Distribution utility: builds the distribution network[16] and leverages its brand recognition to endorse the mini-grid developer so as to encourage customer uptake of connections and demand-generating assets.

Regulatory environment

This model does not require any additional or special regulatory approvals in Uganda as the existing regulations support such collaboration, though this may not hold for all countries.

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[12] For instance, through the U.2.0 pilot, the utility can further consider and test at integration to make battery storage assets part of the distribution network to further increase and improve its reliability.

[13] The utility is learning transferable lessons regarding how to increase customer penetration through demand stimulation through the U.2.0 pilot.

[14] Umeme Ltd operates at a high standard regarding network distribution, metering standards, and the installation of systems as per the regulator guidelines to ensure the network is maintained in a safe working condition. Mini-grids are not required to develop low voltage networks to this standard. However, synchronising with the utility standard as proposed here reduces future grid integration costs.

[15]In this model, the mini-grid developer acquires the regulatory rights to operate and distribute electricity at the sites. This enables the mini-grid developer to gain access to much-needed donor funds and subsidies as they hold the licence to operate at the sites (the entity which acquires the licence to operate at the sites has the legal right to obtain subsidies and donor grants).

[16] The distribution and connection capex would be reimbursed to the utility by the mini-grid developer at 5%, while any o ther fees would be services-based (based on Umeme communication).

Flexible Asset Ownership Model[17]

While scale inevitably brings significant savings, additional cost savings may be achievable by shifting capex to longer-term opex. In this flexible model for generation assets, up-front capital investment costs are reduced by driving down the soft and hard up-front capex (e.g. equipment investment) through standardisation, leasing, and mobility. This model can be led by either the mini-grid developer or by the utility as the primary asset owner, depending on goals and the commercial relationship between the parties.

Rationale

- Quick, standard, turn-key installation of generation assets (solar, battery storage), with easy relocation logistics improves mobility. The mini-grid developer or the utility (whichever is the asset owner) gains increased flexibility to redeploy generation assets in different locations.
- The utility expends less up-front and has flexibility to extend the grid once customers are sufficiently profitable,[18] reducing the risks of serving low-consuming customers.
- Reduced cost per connection enables more connections for the same to achieve access targets and lowers the risk to all development partners.
- Country and utility access targets can be achieved faster and more new connections can be derived from the same assets at modest additional cost.

Roles and responsibilities

- Mini-grid developer: connects households to utility standard; uses the utility's meter and customer relations management (CRM) and billing system; sensitises customers to benefits of reliable power through productive use; provides/markets productive use assets; and focuses on growing demand.
- Distribution utility: builds, owns, and maintains the distribution network and receives any donor or national subsidy[19] for connections (e.g. in Uganda connection subsidy cost is about US $200 per connection).
- Third-party generation equipment supplier: designs, purchases, and installs the generation assets; monitors and controls system hardware; provides maintenance and warranty; continues to own equipment, providing flexible asset lease arrangement to either the utility or mini-grid developer.

Regulatory environment

If the mini-grid developer/operator is the equipment lessee, no additional approvals are needed as the current Ugandan regulations make provision. If the utility is the lower-cost lessor (given their creditworthiness), regulation would need to allow for the distribution utility to acquire distributed generation assets or allow such 'access initiatives' outside the utility's regulated business via a special-purpose vehicle or entity.

[17] For the purpose of this exercise, an interview was conducted with Redavia, which offers a lease on the solar generation equipment. They do not include the diesel generator as part of their leasing offer. A diesel generator is required by most mini-grid developers in order to ensure 24/7 power is available and is used as a back-up system.

[18] For example, Umeme Ltd is generally able to recoup costs from rural customers over 45 kWh/month. The U2.0 pilot aims to grow demand to at least 117 kWh/month in the Mukono communities, more than doubling the benchmark.

[19] This model allows either the mini-grid developer or the utility to adopt and invest using this model. In this example we choose the utility to be the one who adopts this model. This sees the utility acquire the licence to own and operate a generation asset and distribute power. This regulatory approval and licence enables the utility to access any donor funds or subsidies. The entity who acquires the licence to operate at the sites has the legal right to obtain subsidies and donor grants.

Utility Led Asset Purchase Model

This model retains all the capital investment and operating cost reductions resulting from driving down the soft and hard up-front capex (e.g. equipment investment) through standardisation, leasing, and mobility. It replaces capital lease financing with cash purchase of modular generation and storage assets by the utility. This drives down power cost by reducing the cost of capital through leveraging the utility's creditworthiness, purchasing power, and low cost of capital as compared to the mini-grid developer and third-party equipment leasing.

Rationale

- Reduces the cost of capital, one of the most significant factors impacting mini-grid developer power costs.
- The utility's financial benefits depend on the commercial and financial terms negotiated, agreed, and allowed by the regulator.
- The utility, mini-grid developer, and consumer all benefit from retaining the modularity, mobility, standardisation and soft cost reductions, and lower cost of connections.
- Utility leadership enables all stakeholders to benefit from utility relationships with government and regulatory agencies, equipment suppliers, its financial strength, and relationships with lenders and investors.
- This model directly mobilises private commercial capital for integrated electrification investment.

Roles and responsibilities

- Mini-grid developer: connects households to utility standard; uses the utility's meter and CRM and billing system; sensitises customers to benefits of reliable power through productive use; provides/markets productive use assets; focuses on growing demand.
- Distribution utility: builds the distribution network and receives any donor or national subsidy[20] for connection; purchases the generation assets (e.g. solar, diesel, battery storage) directly from the equipment provider/leasing company; provides or contracts operations and maintenance (O&M) from the supplier.
- Third-party generation equipment supplier: designs and installs the modular generation assets (solar, battery storage); provides warranty; and provides assets on a cash sale basis.

Regulatory environment

If the utility is the lower-cost purchaser of assets (because of financial strength and lower capital cost), regulation would need to allow for the distribution utility to acquire distributed generation assets or allow such 'access initiatives' outside the utility's regulated business via a special-purpose vehicle or entity. Similar considerations apply for other countries.

6 Results: estimating impact to costs drivers

To date, many studies have been carried out on standalone IPP mini-grid models, with the most comprehensive study conducted by the World Bank under their Energy Sector Management Assistance Program (ESMAP). The ESMAP study reviewed over 49,000 mini-grids with an average system size of 500 kWp using a standalone IPP mini-grid business globally. The study found average connection costs of US $1,000–US $2,100 and an LCOE of US $0.55–US $0.85/kWh (World Bank, 2019).[21] In a 2018 study, the Rocky Mountains Institute (RMI) found similar results by evaluating over 40 standalone IPP mini-grids (RMI, 2018). The Ugandan utility's connection cost currently ranges from US $740 for a connection without a pole extension and US $1,400 for grid connection cost that requires a one-pole extension (Umeme, 2019). By building on the standalone IPP model for the pilot and exploring how an integrated partnership can enable cost efficiencies and reductions in opex and capex, we can identify the ranges of cost reductions possible, as presented in Figure 1.

[20] The utility adopts this model; it therefore acquires the licence to own and operate a generation asset and distribute power. This regulatory approval and licence enables the utility to access any donor funds or subsidies. The entity which acquires the licence to operate at the sites has the legal right to obtain subsidies and donor grants.
[21] Mini-grids require expensive capital, with lending rates ranging between 15% and 25%. This impacts capex, which further impacts power costs.

While the data used for this analysis are from the real-world pilot, several limitations are helpful to note. First, the mini-grid developer's plan and budgeted costs were originally developed for the purpose of building a small mini-grid (40 KWp) at the Uganda pilot sites, with significant grant funding support. These costs were not originally developed for the purpose of a more efficient, scaled-up business model and are therefore conservative. Second, while the pilot scale is appropriate for comparative purposes, at a larger scale the financial impacts may vary. Third, the Utilities 2.0 partners will likely have other innovative ideas (which are not factored into the current analysis) to reduce power and connection cost, accelerate access, and grow demand as they gain experience on the ground through the pilot. Finally, the Flexible Asset Ownership Model reduces the capex requirement of the solar generation asset. We assume that the diesel generation capex remains the cost of the project developer for modelling purposes, though this does not necessarily have to be the case.

Figure 1 below illustrates the total capex (bar height) and its components (colour bands) are shown for each model. The Flexible Asset model yields the lowest up-front capex by a wide margin.

Figure 1: Comparison of up-front capital costs across models

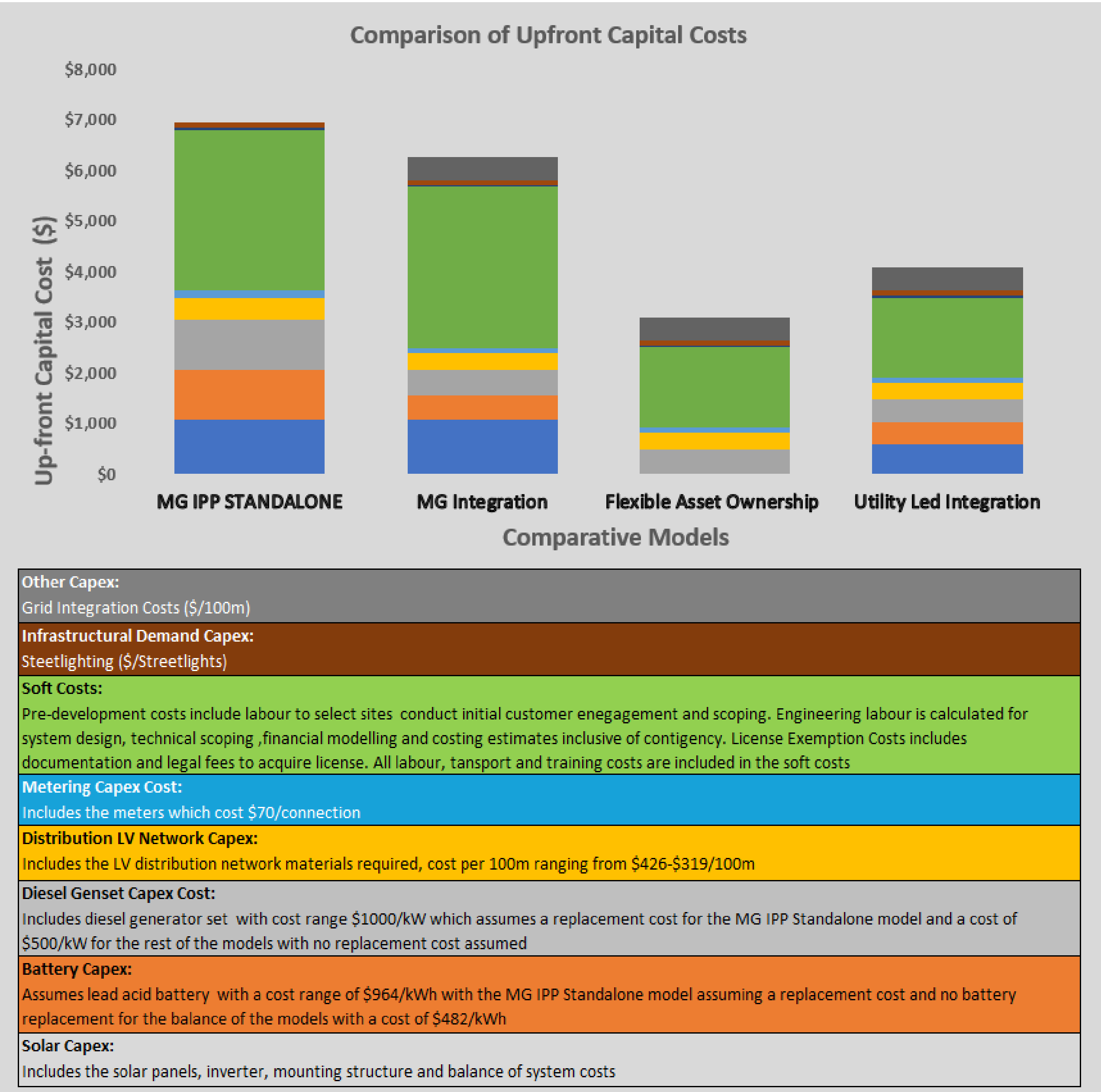

Figure 1 presents the per unit cost of each up-front capital component category for the same 40kw mini-grid project. The solar capex cost is presented in US $/kWp; the battery capex cost is in US $/kWh; the diesel genet capex cost is in US $/kW; the distribution network cost is in US $/100 m; the metering capex cost is in US $/connection; the water purification plant in US $/m^3; and streetlighting is in US $/streetlight. This disaggregation allows us to determine the greatest drivers of cost across the models.

Figure 2: Comparison of LCOE and the sensitivity to cost of capital (via discount rate) across models

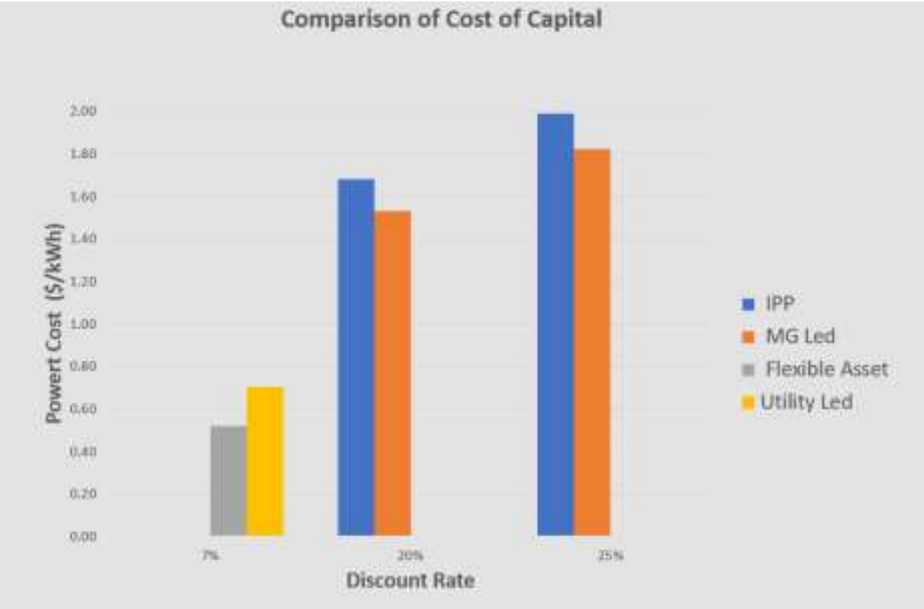

Figure 2 presents a comparison of the models' LCOE also known as power cost. The impact of various costs of capital, as proxied by discount rates, is demonstrated for each model. Figure 3 presents a comparison of the connections cost for each model. The definition, components, and calculation for connection cost can be found in Annex 1.

Figure 3: Connection cost comparison

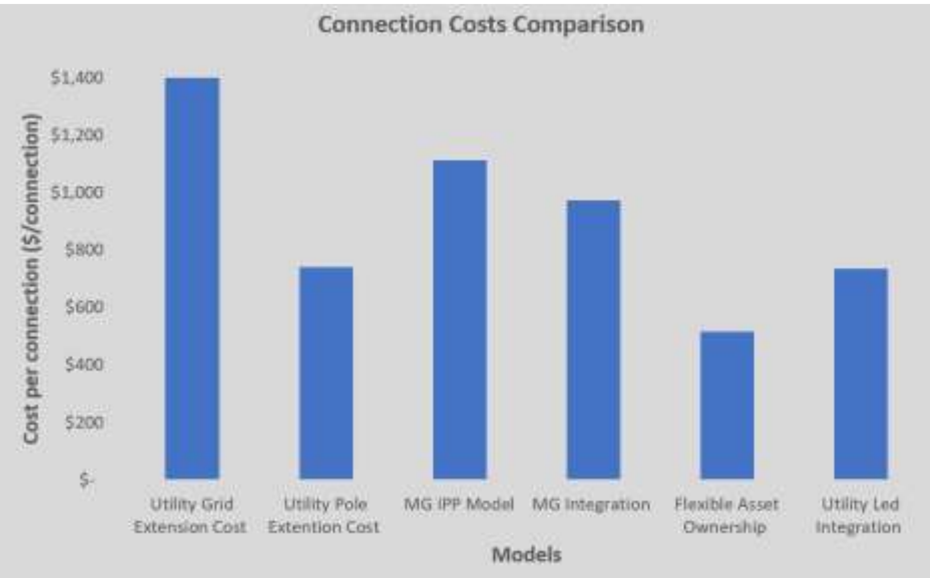

Figure 3 presents a comparison of the connections cost for each model. The definition, components, and calculation for connection cost can be found in Annex 1.

Mini-Grid Led Integration Model: Comparing the Mini-Grid Led Integration Model with the standalone IPP model in Figure 1, it is possible to see the reduction in the overall up-front capital costs for the former compared to the latter. This is partly attributable to the utility being able to procure in bulk and build the distribution network at 25% less than the cost achievable by the mini-grid developer. However, this is a relatively small saving in comparison to overall up-front capital costs. The main difference in costs between these two models is accounted for by the fact that the battery and diesel generation capex cost is reduced as the Mini-Grid Led Integration Model does not assume any replacement costs: the sites will be interconnected to the grid after a period of two years as the demand growth of the site begins to exceed the supply capacity of the solar generation system. These cost reduction measures result in a connection cost for the Mini-Grid Led Integration Model that is 13% lower than the standalone IPP model and 31% lower than the utility's connection cost of US $1,400, as presented in Figure 3. This is a significant finding, as the mini-grid developers' connection cost includes its generation assets and distribution network cost, whereas the utility's connection cost for extending the grid is only the distribution network cost required to make the connection.

Flexible Asset Ownership Model: Comparing the Flexible Asset Ownership Model to the standalone IPP model, one can graphically see a reduction of 56% in the up-front capital cost that is attributed to the reduced capex requirement and reduced soft cost as presented in Figure 1. This model yields the lowest connection cost, US $516, as compared to the utility's connection cost of US $1,400, illustrated in Figure 3. This is attributed to the ability to defer the up-front capex to opex by leasing the solar generation equipment. The soft costs are also reduced as this system is standardised, modular, and leased directly from the supplier, cutting out middlemen mark-up costs. The solar generation and battery costs are no longer up-front capital. Figures 1 and 2 clearly show the capital cost reductions. The diesel genset capex cost is reduced as there is no need to replace this system once grid integration occurs which further reduces the overall up-front capital cost. The O&M costs are increased due to the leasing of the solar generation assets costs being an opex in this model. This is due to the economies of scale, standardisation, and reduced staff cost that is part of the leasing offer provided.

Utility Led Integration Model: This model presents an up-front capital cost reduction of 41% as compared to the standalone IPP model presented in Figure 1. Leveraging the utility's balance sheet to mobilize lower-cost capital, this model enables the utility to purchase the standardised system up-front at a reduced cost for the solar generation and battery equipment (as illustrated in Figure 2). This model brings the same system efficiencies through standardisation, modularity, and direct purchase from suppliers, as presented in Figure 1. This model yields a lower connection cost of US $735 per connection compared to the utility's connection cost of US $1,400, due to the low cost of capital and the standardisation this model creates. This model reduces the total O&M costs and is lower than the standalone IPP model and Mini-Grid Led Integration Model (Figure 2). This is due to the economies of scale, standardisation, and reduced staff cost that is part of leveraging the utility's extensive staff and operational capacity.

Figure 2 illustrates how the cost of capital has a significant impact on the power cost and further illustrates how an entities risk and creditworthiness impacts comes into play to access cheap cost of capital. It further allows us to compare the utility led integration approach, which leverages the utility's balance sheet in acquiring low-cost capital as opposed to the mini-grid developers, who are subject to interest rates varying from 10% to 25%. In both the Utility Led Integration Model and the Flexible Asset Ownership Model the utility leverages its balance sheet in acquiring low-cost capital and in figure 2 yields the lowest LCOE as compared to the IPP and Mini-Grid Led Integration model where a mini-grid developer adopts the models and takes on the role of financing the projects. It is clearly seen that due to the mini-grid developer accessing capital at lending rate of more 2.5 times that of a utility has a significant impact on the cost of power. The Utility Led Integration Model's LCOE of US $0.70/kWh is still significantly less than that of the Mini-Grid Led Integration Model and the IPP model under the 20% cost of capital scenario. This is attributed to the utility's economies of scale, which allow for increased and lower-cost capital, standardisation efficiency gains, modularity, and direct purchase from suppliers. The Flexible Asset Ownership Model leverages the reduced up-front capex combined with a low cost of capital, thus resulting in the lowest LCOE across all models.

To summarise the analytical insights of this business modelling exercise:

- Up-front capex is by far the largest driver of mini-grid connection and power costs. While scale inevitably brings significant savings on equipment purchasing and opportunities for lower-cost modular designs and other 'soft cost' savings, additional cost savings may be achievable by shifting capex to longer-term opex. This can be done by leasing rather than outright purchasing of assets. It may prove especially effective in lowering power costs when grid connection is anticipated in the near-to-medium-term and when expensive equity capital is the primary financing vehicle for capex.
- The cost of capital is generally the next most important driver of mini-grid connection and power costs. Differences in capital costs between a large, cash flow positive regulated utility and a small, venture-backed mini-grid developer are expected and can be leveraged. However, a utility would either need commercial reasons to leverage its balance sheet and regulatory approval to do so, or it would need to conduct such outside of regulated business—such as through an unregulated for-profit enterprise.
- Structural reductions in opex also have a potentially significant impact on power costs, though not as great as capex or the cost of capital. Some opportunities to take advantage of these are by having the utility design and install the mini-grid distribution network—to grid-standard in order to facilitate future integration—and subsequently maintaining it.
- Thus, these alternative business model approaches highlight a major opportunity: government-set electrification goals are challenging with the business-as-usual approach due to current costs, incumbent commercial relationships, and regulation. Innovative integrated electrification approaches can support demand growth, accelerate the pace of connections, and reduce costs. Leveraging strengths of different technology providers could help to mobilize lower cost pools of capital from development finance institutions and scale mini-grids.

This brief demonstrates a major opportunity for the utility, private decentralised energy developers, customers, and the country at large to benefit from integrated business model approaches to electrification, warranting further investigation. Future analysis will explore the implications of such business models at scale. Other organisations, such as Konexa and RMI, are working directly with utilities in Nigeria to explore the value proposition of novel integrated approaches to infrastructure investments and under-grid mini-grids respectively. Future analysis will identify lessons of transferability.

7 Critical success factors for profitable integration relationships

To maximise on these opportunities for impact, integrated business models must be supported by conducive regulation, incentives, and processes. From the Utilities 2.0 experience in Uganda, five key factors for successful implementation, profit, and revenue generation are as follows:

1. Value-stack to grow revenues: For utilities and mini-grids with capped tariffs, the importance of tailoring service around what customers demand cannot be understated. For instance, the Utilities 2.0 customer service model example from Uganda emphasises reliable power, direct customer engagement and management by the mini-grid developer, and free public streetlighting within the community, alongside other pay-for community services such as water purification. This sort of 'value-stacking' of other services alongside electricity has proven successful in India at opening alternative revenue channels that may ultimately be more profitable or enable cross-subsidisation of the electricity service. Mini-grid experience from India and Nigeria shows reliability is key to growing demand (Konexa, 2019). It is also important to balance this demand growth with supply to avoid spikes and maximise generation investments (Kennedy *et al.*, 2019).

2. Capex and tariff subsidies: With capex being the primary driver of mini-grid power costs, subsidies that buy-down the initial investment cost are essential for commercial viability and scale. Large subsidy programmes targeting this problem using results-based financing (a fixed subsidy payment delivered for each connection), auction-based approaches (companies bidding for minimum subsidy levels), and hybrid approaches are already being implemented in many African countries, frequently in partnership with the World Bank, the African Development Bank, and other development partners. The need for subsidies is not an indication of a lack of competitiveness, as subsidies are embedded throughout the power sector value chain across much of the world. Africa is no exception (World Bank, 2016).[22] Recent analysis from Duke University found that electrification programmes in seven countries, which were successful in achieving rapid grid connectivity in recent decades, did so at an average cost of more than US $1,500 per connection, with state subsidies financing on average 86% of those connection costs (Phillips *et al*., 2020). Utility-integrated mini-grid costs are already lower than this cost benchmark. Indeed, the IEA projects that mini-grids will be the least-cost approach for delivering access to roughly a third of rural Africans over the next decade (IEA, 2019).

3. A regulatory environment that allows for experimentation: As shown, all business concepts modelled would require some level of approval or exception. The Utilities 2.0 pilot has faced a steep learning curve, as many current policies and regulations do not have defined or clear processes to enable integrated energy approaches. Allowing for experimentation enables key policymakers and actors in the sector to learn and evolve together. This includes broadening what central utilities are allowed to do (e.g. acquire distributed generation assets or sell low-usage appliances). Some regulatory flexibility on tariff pricing is also probably essential, as donor funding to support mini-grid capex and tariff subsidies is unlikely to materialise at a level sufficient to reach grid parity, at least at any significant scale.

4. Investing in stakeholder engagement across the sector: Engaging with the key energy stakeholders such as policy and key government departments is critical as it enables learning and sharing of information, which needs to happen at an early stage. This creates a network of supportive partners and ensures that key lessons learned are translated into policy and regulation to support integrated energy initiatives. Although stakeholders, policies, and regulations vary by country, early engagement and buy-in is key for successful integration projects; this is echoed in the World Bank Draft National Electrification Strategy for Uganda (World Bank, 2020). There is consensus across key stakeholders regarding the need for better coordination and engagement to ensure effective planning and partnerships can be created (Word Bank, 2020). Power for All has further identified the need for a task force that focuses on integrated energy approaches.[23]

5. Creating an enabling environment to support collaboration and integration: DRE partners and utilities are not accustomed to working together. The utility, being a large, hierarchical, and regulated organisation, may be risk-averse and slower in negotiations compared to small, agile, lean, but often under-resourced decentralised energy providers. A neutral entity that can streamline communication, support the identification of integration opportunities, define roles, and coordinate operations helps partners remain focused and committed to the collaboration. Each partner having designated project leads, and the utility proactively sharing its decision making process, will ensure efficient engagement. An enabling environment will ensure that cross-learning and knowledge transfer takes place, such as the utility learning customer-centric strategy or a mini-grid company learning about standardisation processes.

[22] A 2014 survey of 39 national utility companies in Africa found that utilities received subsidies that allowed them to sell power at prices that were on average 41%—and up to 80%—below what a cost-reflective tariff would dictate.
[23] Power for All hosted a public launch of the Utilities 2.0 integrated energy project on 02 March 2020 in Uganda, attended by key stakeholders such as ERA, REA, Umeme, GIZ, UE, UECCC, and other public stakeholders.

8 Conclusion

This Energy Insight is a deep-dive into mini-grid and utility collaboration, demonstrating the potential impacts of integrated approaches to electrification. Using actual budget data for developers and a utility, we create a framework for identifying ways to reduce key cost drivers, and structure profitable relationships, which are being tested through the Utilities 2.0 pilot in Uganda. We discuss the resulting trade-offs of different interventions and identify areas for future investigation. We find that, by not just focusing on mini-grid IPP capital cost reductions but also on ways to collectively leverage the strengths of each entity, greater cost reductions are possible with benefit to the customer, the utility, and the developers. Modelling the critical success factors for profitable business relationships demonstrates viable paths that support the delivery of faster, cheaper, and more universal electricity connections, demand stimulation, and high quality service, ushering in a utility revolution.

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Annex 1: Methodology

In order to effectively review, assess, and develop the alternative business models as described in this paper, two sets of frameworks were used:

a) the LCOE comparison; and

b) the connections cost comparison (using an income statement framework)

a) LCOE

LCOE is a measure of the average net present total cost of energy generated for a generating plant over its lifetime. Simply described, it presents the break-even cost a generating plant needs to charge in order to recoup its cost.

LCOE describes lifetime costs (capital and operational) divided by the total amount of energy produced to give a cost per unit of energy expressed as, for example, US $/kWh. LCOE is presented in units of currency per kWh of electricity (e.g. US $/kWh). It gives an indication of the minimum average tariff at which electricity must be sold in order to break even or recover costs. It allows the comparison of different generating technologies (e.g. wind, solar, natural gas) of unequal life spans, project size, different capital cost, risk, return, and capacities.

While there are multiple approaches to calculating the LCOE, mathematically we employ the following equation:

$$LCOE = \frac{Sum\ of\ cost\ over\ lifetime}{Sum\ of\ electrical\ energy\ produced\ over\ lifetime} = \sum_{t=1}^{n} \frac{(Ct + Ot + Vt)}{(1+d)^t} \Bigg/ \sum_{t=1}^{n} \frac{Et}{(1+d)^t}$$

Where:

Ct = initial investment capital cost in year t

Ot = operating expenses in year t

Vt = variable costs such as fuel and batteries in year t

d = discount rate

t = time period

n= lifetime of the system

All LCOE approaches use some form of discounting future costs of revenues and cash flows to arrive at a comparable ‘levelised present value’ cost and there is wide discretion in choosing the discount rate. In these models, the discount rate used has a very significant impact on the resulting cost of power (LCOE). In this analysis, we have used two approaches:

- **Cost of capital:** The LCOE model is used to evaluate the impact of cost of capital. As a result, we have used the discount rate as a proxy for the capital cost. In the Utility Led Integration Model, only one discount rate was used of 7.3% and this led to the lowest LCOE across the models.
- **Wide range:** Given the wide range of capital markets and economic conditions (interest rates, inflation, currency, and other factors), mini-grid financing in developing countries ranges from 100% equity financing to 80% subsidised. We report LCOE across a range of discount rates between 10% and 25%, as this is the comparable range reported in the mini-grid industry.

Table 1: Analysis results of comparative connection and power costs (LCOE) under different partnership models

	Model description	Grid connection cost (US $ per customer)	LCOE (power cost) (US $ per kWh)	Analysis notes
Referenced case studies on business models for mini-grids (IPP model)	ESMAP: IPP model	US $1,000–US $2,100	US $0.55–US $0.85	• ESMAP reviewed over 49,000 standalone IPP mini-grids globally • Average system size 500 kWp
	RMI: IPP model	US $1,000–US $2,100	US $0.6–US $1.00	• RMI reviewed over 40 Nigerian standalone IPP mini-grids • Average system size 125 kWp • Discount rate range 10%–15%
Uganda utility grid connection cost and tariff	Utility	US $160–US $1,485	n/a	
U.2.0 pilot: integrated alternative business models developed	IPP model: U.2.0 pilot	US $1,113	US $1.15–US $1.40	• Modelled with the U.2.0 Uganda pilot figures, 40 kWp mini-grid system size • LCOE discount rate range of 10%–15% • Mini-grids built on land in Uganda are subject to a tariff cap of US $0.3/kWh • Cost within range compared to referenced studies
	Mini-Grid Led Integration Model*	US $972	US $0.09–US $1.24	• Modelled with the U.2.0 Uganda pilot figures, 40 kWp Mini-Grid system size • LCOE discount rate range of 10%–15% • Mini-grids built on land in Uganda are subject to a tariff cap of US $0.3/kWh
	Flexible asset ownership	US $516	US $0.61–US $079	• Modelled with the U.2.0 Uganda pilot figures, 40 kWp mini-grid system size • LCOE discount rate range of 10%–15% • Mini-grids built on land in Uganda are subject to a tariff cap of US $0.3/kWh
	Utility Led Asset Purchase Model	US $735	US $0.70	• Modelled with the U.2.0 Uganda pilot figures, 40 kWp mini-grid system size • LCOE discount rate of 7.3% used as per Umeme lending rates of 2019 • Mini-grids built on land in Uganda are subject to a tariff cap of US $0.3/kWh

Table 1 compares the connection and power cost across the models to the ESMAP and RMI study, which is viewed as the industry benchmark for mini-grids. This tables provides a synopsis of the results and clearly indicates that the power costs achieved for the three alternative models are within the industry benchmark costs. The connection cost illustrated the impact of an integrated energy approach and how this reduces the connection across the three models as compared to ESMAP, the RMI study, and the Utility connection costs.

b) Connections cost (using income statement framework)

A connection is defined as a point at which an incoming utility provides the necessary infrastructure and connects to a user (customer) in order to serve them with a service such as electricity, water, telecommunications, or gas. In the utility sector, the connection cost is made up of extending poles (if needed), power lines, and installing a meter and 'ready box' service panel for new customers. It does not include household wiring beyond the 'ready box'. Decentralised energy solutions often include some form of power generation and/or storage as part of the 'package' offered to customers along with a connection. By contrast, for most utilities, generation is separate and 'upstream' from the distribution and connection value chain. Most mini-grid models include the capital and operating costs of generating electricity as well as distributing it; there is no 'perfect' way to compare 'connection costs' between the mini-grid and utility. Moreover, many mini-grid developers are now including productive use assets or other demand generation investments in capital and operating expenses to help drive increased revenue. This further complicates mini-grid-to-utility cost comparisons, especially for connections costs.

The connection cost calculation is as follows:

$$Connection\ Cost = {}^{Total\ Capital\ Cost}/_{Total\ number\ of\ connections}$$

An example calculation for flexible asset ownership connection cost is as follows:

$$Connection\ Cost = {}^{198{,}188}/_{384} = \$516/connection$$

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The views expressed in this Energy Insight do not necessarily reflect the UK government's official policies.