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WORKING PAPER

Are Mini-grid Projects in Tanzania Financially Sustainable?

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While it is commonly acknowledged that mini-grids are the new pathway to bridging the high electricity access deficit in Sub-Saharan Africa (SSA), comparably few studies have assessed how existing regulations and tariff policies in SSA affect their potentials to attract the number of private investments required to scale-up deployments. Private investors' participation is particularly crucial to meet the annual electrification investment needs of $120 billons in SSA. We study the regulatory framework, the tariff structure and the subsidy schemes for mini-grids in Tanzania. Additionally, using an optimisation technique, we assess the profitability of a mini-grid electrification project in Tanzania from a private investment perspective. We find that the approved standardised small power producers' tariffs and subsidy scheme in Tanzania still do not allow mini-grid for rural electrification projects to be profitable. A further study is required to identify successful business models and strategies to improve mini-grids profitability.

JEL CODES : D4; N47; Q42; Q48

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1. Introduction

Mini-grids[1]are becoming the mainstream solution to electrification problems in high electricity access deficit countries, especially in Sub-Saharan Africa (SSA), where there is evidence of a significant gap between urban and rural population (IEA et al., 2019). Given the enormous solar energy potential (about 300,000 Giga Watts) of SSA and the declining cost of renewable energy technologies, it is expected that by 2030, solar mini-grid solutions would provide more than 60% of rural electricity access in SSA (IEA, 2017). Large-scale commercial deployments of mini-grids require a degree of profitability to ensure their financial sustainability (Peters et al., 2019). For this to happen, new regulations and cost-reflective electricity tariffs for small power producers are needed to incentivise private sector participation in the power sector. Private investors' participation is particularly crucial to meet the annual electrification investment needs of $120 billons in the region (IEA, 2019). However, in most SSA countries, non-cost-reflective electricity tariffs as a result of institutional and political pressure to keep tariffs low and high commercial risk of mini-grid projects[2] are significant barriers that disincentivise private mini-grid developers from investing in the power sector (Eberhard & Shkaratan, 2012; Peters et al., 2019; IEA et al., 2019).

Amidst these challenges, Tanzania policymakers have implemented innovative policies and regulatory frameworks that have seen increased investments in small power projects. According to the World Bank (2019), Tanzania's comprehensive approach to mini-grid developments has achieved one of the fastest results in electricity access (56% and 73% increase in national and rural access rates respectively over the past decade) in SSA. The Tanzanian mini-grid model is anchored on public-private partnerships, where the government introduced a regulatory framework and legal and financial support to attract private mini-grid developers (Peters et al., 2019). This remarkable performance makes Tanzania a unique case of interest in Sub-Saharan Africa. Therefore, this study is interested in understanding the factors that account for the proliferation of small power projects in Tanzania. Besides, given the need for increased private sector investments in mini-grid deployments to meet Tanzania's electrification needs, we further investigate whether the current tariff structure in Tanzania is cost-reflective for private commercial mini-grid developers. More precisely, the paper studies the profitability[3] of commercial mini-grid project in Tanzania from a private investment perspective.

Understanding mini-grid projects' profitability from an investment perspective is particularly crucial for designing optimal regulations and cost-reflective tariff schemes to attract adequate private sector investments in the power sector. However, this is a less explored area in the literature. Comparably, only a few quantitative studies have critically assessed how existing regulations and tariff policies in SSA affect mini-grid projects' potential to attract the number of private investments required scale-up deployments (Williams et al., 2018). From another perspective, there is no consensus in the literature about whether mini-grid projects in SSA are profitable enough to crowd in private financing of mini-grid projects. On the one hand, some researches argue that mini-grid projects powered by renewable energy are economically viable and capable of paying-off their financing cost and earning adequate returns for investors (Okoye & Oranekwu-Okoye, 2018; Arowolo et al., 2019). On the other hand, other studies also argue that mini-grid projects in SSA are not economically feasible; thus, it requires subsidies to enable investors to recover their production cost (Azimoh et al., 2016; Naqvi et al., 2017; Adaramola

[1] Mini-grids

[2] Commercial risks refer to low customer ability to pay for power and or low demand for power due to inefficient power use.

[3] A situation whereby a mini-grid developer can recover its costs and earn a target return on investment as specified by the regulator.

et al., 2017). This controversy about the profitability of mini-grid projects in SSA further strengthens the motivation of this paper.

Firstly, we review the regulatory policies and the operation of mini-grid systems in Tanzania to draw useful lessons for other SSA countries. Secondly, we estimate the economic buoyancy vector[4] of the study area to assess the possibility of productive use of power and consumers' ability to invest in clean energy. Thirdly, we use an optimisation model to estimate the Levelized cost of energy (LCOE) for three mini-grid project designs: Thermal, PV+Battery and Hybrid systems in Mafinga Town. The model uses a derivative-free optimisation[5] to search for the least costly system. The LCOE for the least costly system is then compared with the regulated mini-grid tariff and the available subsidy schemes in Tanzania to access the mini-grid project's profitability.

Mafinga Town, the study's specific location, is based on recommendations by the Electricity and Water Regulatory Authority (EWURA) and the World Resource Institute (WRI). It is one of the preferred locations for private mini-grid investments in Tanzania. Additionally, this choice is also motivated by other factors, including high electricity need (92% unconnected households) and the presence of a high solar resource of 6.24 kWh/m^2.

Based on our analysis, we find privately operated mini-grid projects in Tanzania not profitable. Contrary to our expectation, the increased investments in mini-grid projects in Tanzania were rather led by the government, faith-based, not-for-profit organisations and community-based initiatives. Although there are quite a few private developers in Tanzania, most of them were developing mini-grids to meet the energy needs of their subsidiary industries. The surplus electricity is then fed into the national grid or sold to nearby communities at the approved rate. Therefore, with the current approved mini-grid tariffs in Tanzania, we argue that privately owned commercial mini-grid projects are not financially sustainable.

We organise the rest of the paper as follows. Section 2 presents a background of mini-grid development, regulation, financing and operation in Tanzania. In Section 3, we describe both the methodology and the study area chosen for this paper. Section 4 discusses the results from our LCOE model *vis-à-vis* the current tariff structure in Tanzania. Section 5 concludes with some policy recommendations.

2. History of mini-grid projects in Tanzania.

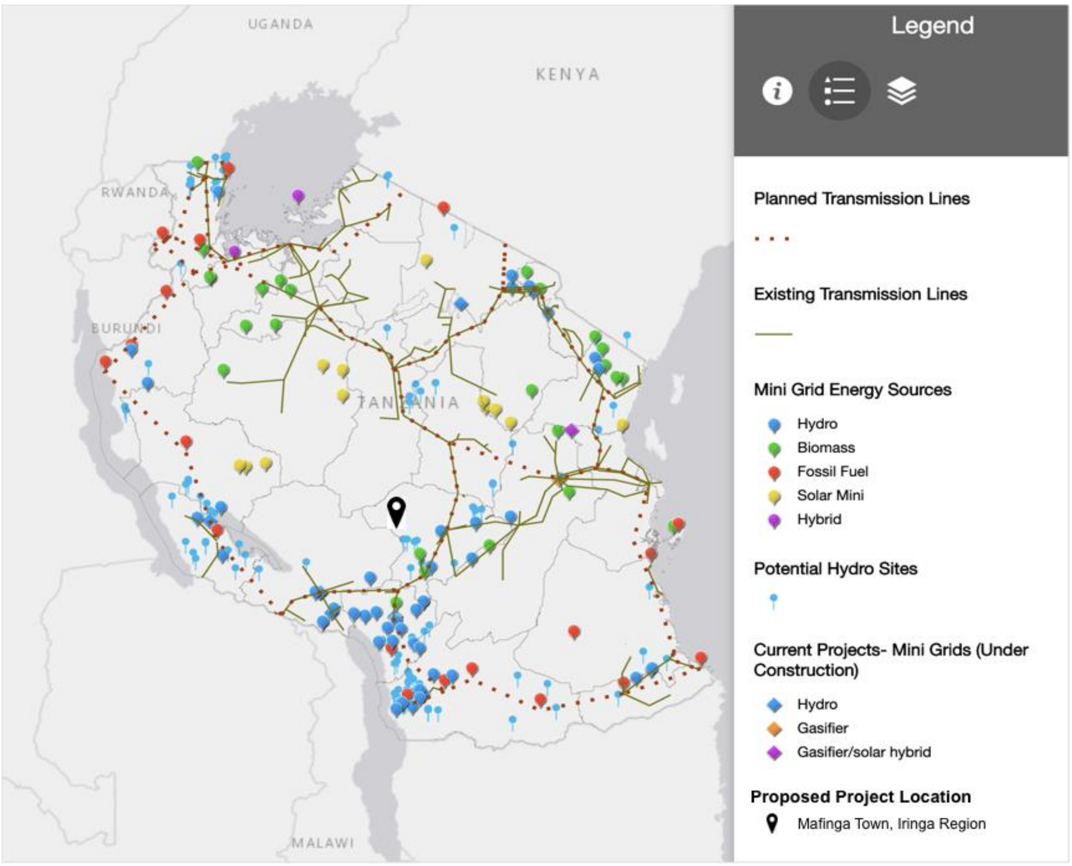
Tanzania has rich experience in terms of mini-grid developments and regulations. The development and operation of mini-grid systems in Tanzania is dated as far back as 1908 during the colonial era, where the colonial masters develop mini-grid systems to power railway workshops, mining and agricultural industries (Org et al., 2016). During the same period, faith-based organisations also develop mini-grid systems to provide social services in a particular part of Tanzania. After independence in 1964, Tanzania continues to develop mini-grid systems to provide electricity access to decentralised communities in the country. Despite Tanzania’s long history with mini-grid systems development, electricity access in the country is still low. According to the World Bank (2016b) household electrification survey, only 32.8% of Tanzanians have access to electricity. About 6.2 million rural households in Tanzania lack access to electricity (World Bank, 2016b). Given the dispersed type of settlement in rural Tanzania, grid extension

[4] Economic Buoyancy Vector: a concept developed by the World Resource Institute for a rural household’s wealth and ability to invest in clean power.

[5] Derivative-free optimisation: It is a search algorithm that the model employs to find the most efficient system configuration that delivers the lowest LOCE; however, since this is a non-derivative method of optimisation, the optimality cannot be guaranteed.

is not a cost-effective option for extending electricity access to rural consumers. Therefore, TANESCO, the national utility company, uses standalone mini-grid systems powered by diesel and natural gas to extend electricity access to isolated communities. Tanzania currently has about 109 mini-grid systems in 21 regions operated by the national utility company, faith-based organisations, local communities and private developers. Figure 1 shows the various types of mini-grid systems in Tanzania as of 2014. It highlights areas suitable for various mini-grid technologies based on the energy resources available in those areas. The black location indication on the map represents the specific area of interest for our study.

Figure 1: Mini-grid Projects in Tanzania



Source: Authors' elaboration from the WRI energy access map

2.1 Regulatory Framework

After several years of operations, Mini-grid developers in Tanzania still face some challenges, including a lack of regulatory framework and a specific tariff policy for mini-grid systems. The Electricity and Water Utilities Regulatory Authority (EWURA), which oversees Tanzania's power sector regulation, introduces a specific regulatory framework for small power producers (SPPs). The regulatory intervention saw the implementation of standardised power purchase agreements (SPPA) and standardised power purchase tariffs (SPPT), popularly known as feed-in-tariffs (FiT) for SPPs. However, the first generation of feed-in-tariffs EWURA introduced was technology-neutral, which means that the FiT favours some technologies. The regulator also quotes the FiTs in the local currency, which exposes developers to high currency risks.

In response to the above challenges, in 2008, the regulator developed attractive mini-grid policies and regulatory frameworks that address the power sector's challenges and encourage further investments in renewable energy-based mini-grid systems in the country (Org et al., 2016). EWURA revised the SPP regulatory policies to provide clear policy guidance for SPPs connected to the national grid and mini-grid systems that serve isolated communities. The regulations require developers of mini-grid systems with capacities of 1 MW and above to obtain a license from the regulator before commencing operations. Mini-grid systems between 1 MW and 100 kW are required to register with the regulator, whereas projects below 100 kW require neither a license nor the regulator's tariff approval. Additionally, EWURA implemented the technologic-specific and size-specific feed-in-tariffs for various mini-grid technologies. Feed-in-tariffs for mini-grid systems connected to the national grid were denominated in the US dollar to reduce the currency risks. Also, EWURA removed taxes and import duties on renewable energy technologies to make them more competitive. Additionally, the EWURA introduced a mini-grid information portal and geospatial portfolio planning tools, which provide comprehensive information on mini-grid developments in Tanzania and reduce pre-site preparation costs significantly.

2.2 Financing mini-grid systems in Tanzania

Furthermore, from 2008 to 2014, the Tanzanian government, with support from the World Bank, establish some financial support schemes to encourage local mini-grid developers to invest in the rural electrification programme. The financial support scheme includes Smart Subsidies and Credit Line Facility. Under the Smart Subsidies, policymakers assist local developers with a matching grant of $100,000 for environmental impact assessment and business plan development. Also, as part of the Smart Subsidies, developers benefit from a performance grant of $500 for each household connected. However, renewable energy-based mini-grid systems require high initial capital investments that are often difficult for local developers to access from financial institutions due to doubts about mini-grid projects' economic viability (Ahlborg & Hammar, 2012). Therefore, the government introduced the US $23 million credit line facility to provide commercial loan to small power producers. The loan facility is accessible through the Tanzania Investment Bank with 15 years payback period. Additionally, the World Bank has also made available $75 million under the Renewable Energy Rural Electrification Program to support the development of mini-grid projects between 2015 and 2019.

Despite the above regulatory interventions, there is still uncertainty among private developers about the fate of their investments in the arrival of the national grid. Up to date, there is no clear regulatory directive in that regard. However, the regulator envisages the following possible options. Firstly, the mini-grid operator can continue its operations as a small power producer and sell excess electricity to TANESCO. Secondly, in the event where the mini-grid operator is unable to compete with the national utility, the operator has the option to decommission its generation asset and buys electricity from TANESCO as a small power distributor. Lastly, the operator has the option to decommission its generation asset and sell-off its distribution asset to TANESCO.

2.3 Tariff Regulatory Policy in Tanzania

Electricity regulators in SSA face the choice of applying the uniform national tariff or the cost-reflective tariffs for mini-grid systems operators. The uniform national tariff is a fixed regulated rate that the regulator charges all customers irrespective of whether they are served by the national grid or by mini-grid systems. The idea behind this tariff scheme is to ensure equality and fairness across all consumer types. Mostly, utility regulators fix the electricity tariff for commercial mini-grid operators at the same rate as the state-owned utility service, which the government often subsides below the cost of supply (Reber et al., 2018). Usually, the main drivers of this tariff schemes are political and social considerations. Mini-grid systems operators struggle to be competitive under the national uniform tariff scheme as their production costs are often significantly higher than the uniform national tariffs.

Under the cost-reflective tariff scheme, the regulator deregulates the electricity rates, and operators are allowed to charge rates that will enable them to recover the power supply costs and earn favourable returns on their investments. With the cost-reflective tariff scheme, economic considerations are the main determinants of the electricity rates underpinned by 'willing buyer – willing seller agreements.'

Therefore, it is perceived as a more effective scheme for attracting private mini-grid developers and encouraging efficient electricity use (ECA, 2017). However, it does not consider the consumer ability to pay for power.

According to the Economic Consulting Associates (ECA), there is a mid-way approach that serves as a third option for regulators. Under the mid-way approach, operators are allowed to charge regulated cost-reflective tariffs. However, the regulator and the operator must agree on the rate of financial returns and the payback periods (ECA, 2017). In the case of Tanzania, the regulator is more inclined towards the mid-way approach. EWURA sets the mini-grid tariffs relatively higher than the grid rate (TZS203.11/kWh or $0.08/kWh). However, EWURA determines the rate of financial returns and the payback periods for the mini-grid operators. EWURA uses the 'avoided cost' methodology to determine the electricity tariffs for small power producers in Tanzania. Moner-Girona et al. (2016) define avoided cost as “the price that the utility would have paid if it had to produce the power by itself or bought it.” In order words, it is the best-forgone alternative for a set of consumer groups at a particular location. Therefore, “the avoided cost, therefore, serves as the ‘floor’ price (a price specified in a market-price contract as the lowest purchase price of electricity, even if the market price falls below the specified floor price)” (Moner-Girona et al., 2016). Once the floor price is determined, a capacity band is applied to balance the tariff option for the various mini-grid technologies effectively. The approved standardised small power producers’ tariffs are then subject to review once every three years. Table 1 presents the recently updated approved tariffs for various mini-grid system operators in Tanzania.

Table 1: Approved Standardised Small Power Producers Tariffs (Selling to the Grid)

Capacity (MW)	Minihydro USc/kWh	Wind USc/kWh	Solar USc/kWh	Biomass USc/kWh	Bagasse USc/kWh
0.1 – 0.5 MW	10.65	10.82	10.54	10.15	9.71
0.51 – 1 MW	9.90	9.95	9.84	9.34	9.09
1.01 – 5 MW	8.95	9.42	9.24	8.64	8.56
5.01 – 10 MW	7.83	8.88	8.34	7.60	7.55

Source: EWURA, 2019a.

2.4 Types of Mini-grid operations in Tanzania.

Tenenbaum et al., 2014. place mini-grid operators in Tanzania under four categories.

The first category consists of operators who sell electricity only to retail customers. This category of developers operates isolated mini-grid systems to serve rural communities with neither grid access nor standalone mini-grid systems owned and operated by TANESCO. Therefore, developers deal directly with retail consumers who are primarily rural households and commercial customers. Developers in this category face several challenges, including high initial capital investment requirement, which is often difficult to access from financial institutions, non-cost-reflective tariffs, risk of productive use of power and customer ability to pay for the power consumed. The proposed project for this study falls under this category of mini-grid operators.

The second category of mini-grid operators is those whose primary objective for developing mini-grid systems is to ensure a reliable supply of electricity for their internal industrial needs. The excess power produced is feed into the national grid at an approved standardised price. In some cases, operators in this category commit extra investments to expand their capacities to serve surrounding communities and the national utility. Two examples of this category of mini-grid systems operators are the Tanzania Wattle Company’s (TANWATT) 2.5MW biomass mini-grid system at Njombe and the Mwenga 4MW mini-hydro plant operated by the Rift Valley Energy (RVE). RVE is a 100 percent subsidiary of Rift Valley Corporation, the Mufindi Tea and Coffee Company owners in Tanzania (Ghosh et al., 2017).

The third category of mini-grid operators in Tanzania describes mini-grid developers whose primary objective is to install renewable energy-based mini-grid to produce power and sell at a wholesale price to TANESCO in districts where the national utility service operates costly standalone diesel-based mini-grid systems. Societal and political pressure constrain the national utility (TANESCO) to retail electricity to its customers at the uniform national tariff rates irrespective of the electricity supply source. The national utility buys power from private mini-grid developers at the rates presented in Table 1. Likewise, developers also prefer to sell electricity at wholesale price to the national utility to avoid societal pressure and customer agitations to sell electricity at the uniform national rate. The biomass mini-grid plant at Mafia Island is a typical example of the third category of mini-grid operators in Tanzania.

The fourth category of mini-grid systems operators in Tanzania consists of operators who produce electricity and sell at wholesale price to the national utility described above and at retail price to new customers. Developers in this category with explicit regulatory approval from EWURA may use cross-subsidies from both TANESCO and commercial customers to sell electricity to rural households at the national uniform tariff rate. It implies that commercial customers may have to pay the approved standardised SSP tariff (see Table 1) as TANESCO, which is relatively higher than the uniform national tariff. The Andoya hydroelectric mini-grid project falls within this category of operators.
The third and the fourth categories of mini-gird developers face a potentially high risk of the arrival of a low-cost national grid in their operational area.

The above review of mini-grid systems regulation, financing and operation in Tanzania demonstrates firm commitments and targeted regulatory frameworks from policymakers to create a viable and dynamic market for mini-grid systems to proliferate in the country. The financial interventions implemented are crucial for addressing the financing barrier for local mini-grid systems developers. However, Ahlborg & Hammar (2012) argue that the financial supports available to local developers account for only 30% of the country's total cost of mini-grid projects.
Moreover, large portions of the financial support scheme form a loan that the mini-grid operators must pay back within a short period. In this regard, mini-grid systems' operations should be financially sustainable to pay off its financing costs. Also, depending on the categories of mini-grid operations in Tanzania, it appears that some developers have significant advantages over others. For example, the second category of developers discussed above has a real need for industrial power from their internal commercial entities with a strong financial ability to pay for the cost of power. Besides, they use waste products from their core business operations to produce electricity at a little cost. Therefore, selling the excess electricity to the national grid and surrounding communities at the uniform national tariff rates may not significantly impact their operations' financial sustainability. However, the other categories of developers in Tanzania may have to incur either high initial capital expenditure (CAPEX) or costly operational expenditure (OPEX) to produce electricity on a commercial scale.
Additionally, both the third and the fourth categories of mini-gird developers face a potentially high risk of delay payment or non-payment from TANESCO, given the conditions under which the main off-taker operates (selling electricity at a highly subsidised rate). For instance, Org et al. (2016) report that the inability of TANESCO to pay one of its suppliers, the AHEPO mini-hydro project, affects the long-term sustainability of the project. It is also unclear whether the approved SPPs' standardised rates for selling electricity to the grid are cost-reflective for all categories of developers. Even more concerning is the first category of operators whose operations face several risks, including the risks of productive

use of power, ability to pay for power, and the challenge of building a robust financial model to attract private equity investors.

3. Methods and Data

This section describes the methodology adopted by this study. We provide an overview of the selected community for the study, followed by an explanation of the two indicators used to assess the proposed project's profitability: the economic buoyancy vector and the LCOE. Later, we describe the data used for this project.

3.1 Description of Project Site – Mafinga Town

Our study's area comprises five villages in Mafinga Town, located in the Mufindi district of central Tanzania (Iringa Region). The villages are Ivambinungu, Mkombwe, Pipeline, Malingumu, and Mjimwema. According to the 2012 Tanzania national census, Mafinga Town has a total population of 51,902 and a total household of 12,532 (The United Republic of Tanzania, 2013). We choose Mafinga Town for our study because both EWURA and the World Resource Institute (WRI) identify the Mufindi district as a preferred location for mini-grid enterprise investment. Both in terms of the rich solar energy resource potential and the economic buoyancy of the district. However, the district has one of the lowest electrification rates in the region. Out of the total households in Mafinga Town, 11,629 households with about 92.8% do not have access to electricity. Kerosene remains the primary energy source of light in the entire Mafinga Township to the extent that its usage has decreased by only 3.8% between 2012 and 2016 (The United Republic of Tanzania, 2017). The five villages considered in this study have a total unconnected population of 18,140 people and 4,424 unconnected households. Figure 2 shows a satellite image of Mafinga Town with the five villages earmarked for mini-grid electrification.

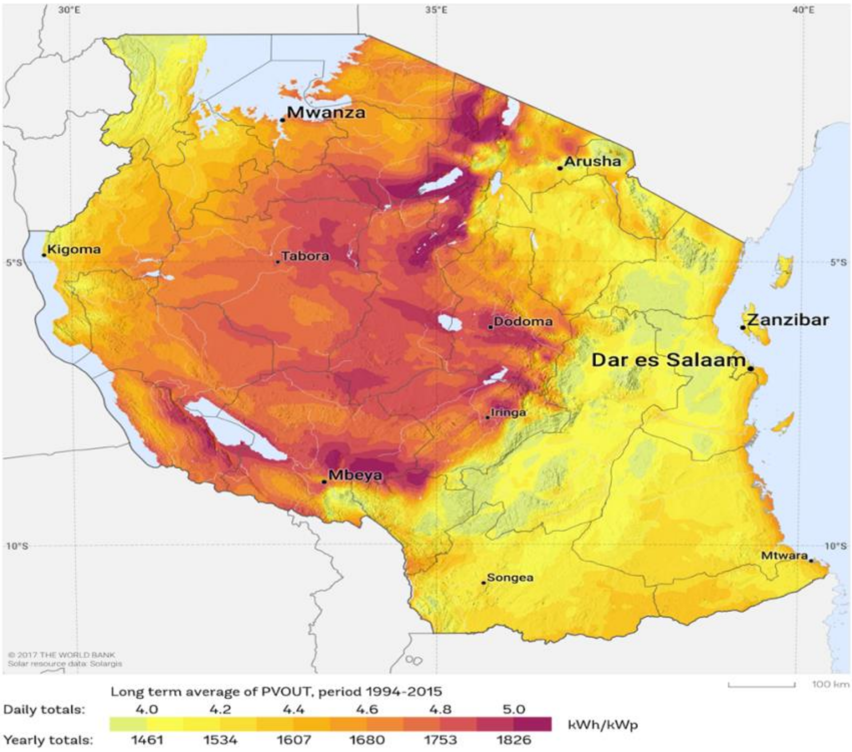
Figure 2: Satellite image of Mafinga Town

Source: Tanzania Mini-grid Portal GIS.

Solar Resource

The Iringa region is considered to have one of the highest solar energy resources in Tanzania, as presented in Figure 3 (ESMAP, 2015). The Global Horizontal Irradiance (GHI) of the region located at latitude 7.67 south, and longitude 35.75 east is estimated at 6.24 kWh/m2 (ESMAP, 2015). We use the HOMER software, linked to NASA's Surface Meteorology and Solar Energy (SSE) dataset, to estimate the region's average daily radiations. The SSE has proved to be an accurate and reliable source for providing solar and meteorological data for regions with sparse or no surface measurement data (Pavlovi et al., 2013). Additionally, the SSE data set is explicitly formatted to support PV power system designs.

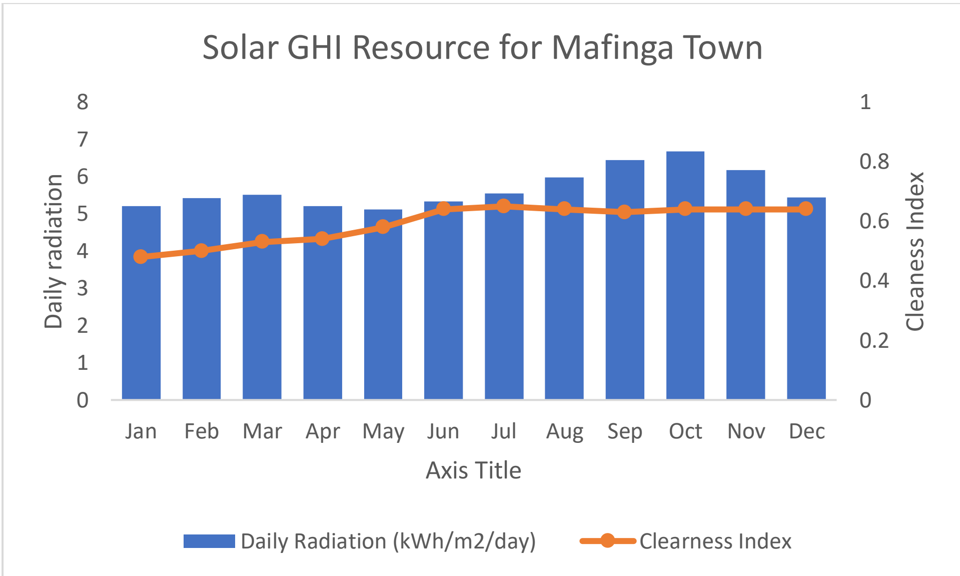
Figure 3: Photovoltaic Power Potential of Tanzania



Source: World Bank Group, 2015

The graph in Figure 4 illustrates the average daily variations in the solar resource data for the Iringa region downloaded from NASA's SSE dataset.

Figure 4: Solar GHI for Mafinga Town- Iringa Region, Tanzania



Source: Authors' elaboration with data obtained from the SSE database, 2019

3.2 Economic Buoyancy

Economic buoyancy is a concept developed by the WRI to assess private mini-grid projects' viability in rural SSA. The WRI first explores the concept in Tanzania as part of the energy access map, identifying suitable areas for public and private electrification projects. They base the concept on three indicators: Livestock, iron roofing sheet and radio ownership, which has their weight in representing a household's wealth and ability to invest in clean power. However, for this study, we modify the above indicators slightly to replace the iron roofing sheet with modern roofing materials and radio ownership with electronic gadget ownership to make the indicators more inclusive.

Livestock ownership

According to the WRI, livestock represents the least weight (1) in the household's wealth determination because it is of less significance among the three indicators. About half of the population in Tanzania owns livestock. Out of the population that keeps livestock, 62% are in rural areas, and 23% in urban areas (National Bureau of Statistics, 2015).

Modern roofing materials

Modern roofing materials such as iron sheets, tiles, concrete and asbestos, weighs more (3) in aggregating a rural household's wealth. They are commonly found in urban areas (97%) are more costly than traditional rural roofing materials such as thatch, grass, leaves, mud, etcetera. Therefore, a rural household's ability to afford modern roofing materials is a significant indication of wealth; thus, the reason for a higher weight in aggregating the rural household's wealth of a rural household.

Electronic Gadgets

The WRI assigns a weight of 3 to electronic gadgets ownership in a rural household's wealth determination. Electronic gadgets ownerships are more familiar with urban households (75%) than rural households (66%), according to Tanzania's 2012 population census. Therefore, the concept assumes that a rural household's ability to afford electronic gadgets such as radio and television are essential indicators of wealth.

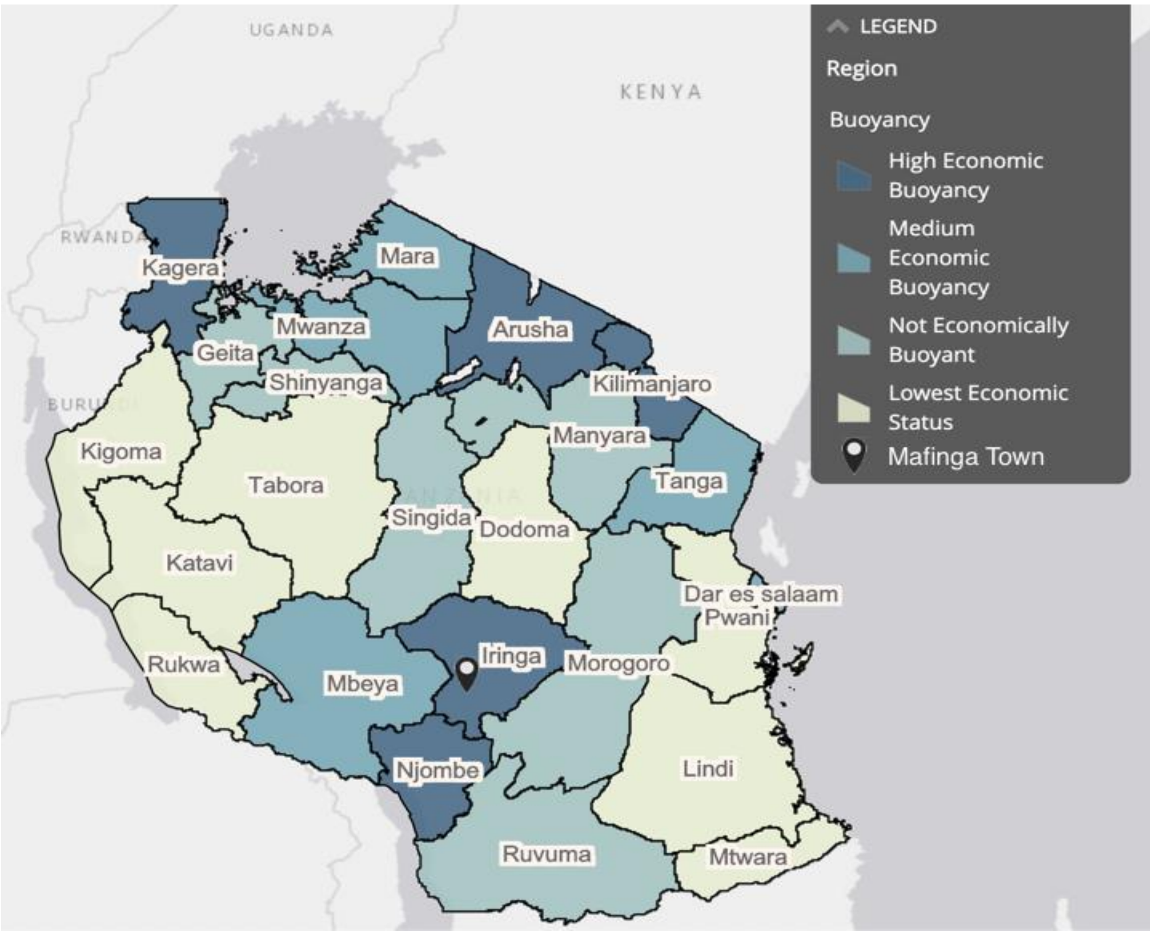
The economic buoyancy vector of Mafinga Town is estimated using Equation 1.

Equation 1: Economic Buoyancy Vector (EBV)

$$EBV = \frac{[(\%\text{ Livestock } \times 1) + (\%\text{ Modern roofing material } \times 3) + (\%\text{ Electronics } \times 3)]}{7} \quad (1)$$

Based on the 2012 national census data of Tanzania, livestock, iron roofing sheet and radio ownership in Mafinga Town are 26.4%, 96.1% and 79.4%, respectively. Following the WRI's methodology presented in Equation 1, we estimate the economic buoyancy vector of Mafinga Town as approximately 79%, which suggests the financial ability of consumers to invest in clean energy. Figure 5 presents the economic buoyancy map of Tanzania,

Figure 5: Economic Buoyancy Map of Tanzania



Source: Authors' elaboration from the WRI (Energy Access Map of Tanzania)

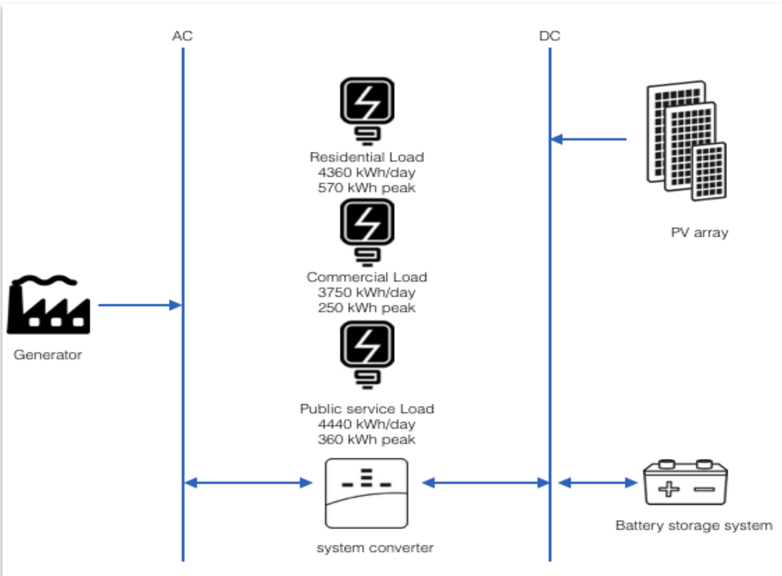
3.3 Levelized Cost of Energy

The LCOE is the cost of producing a kilowatt unit of electricity. To compute the LCOE, we use the Hybrid Optimisation of Multiple Electric Renewables (HOMER), a computational software developed by the Alliance for Sustainable Energy System (ASES). For the proposed project, we consider three system design options: Thermal generation with a diesel generator, renewable energy generation with PV + Battery and a Hybrid System with a combination of thermal and renewable generation sources. The objective is to evaluate the economic and technical feasibility of these technology options. We use the HOMER software to model the project's power system's physical behaviour by performing energy balance calculations and simulating all feasible system configurations such as sizing system components (PV array, Battery, system convertor and generator). The software calculates the energy flow to and from each component to determine the best system configurations required to meet the load demand and estimate the system's minimum capital and operating and maintenance costs over the project's lifetime. HOMER uses a derivative-free optimisation to search for the least costly system ranked by the LCOE, which is then compared with the approved mini-grid tariff to determine the mini-grid project's profitability.

There are other mini-grid modelling systems such as Stochastic Techno-Economic Microgrid Model (STEMM), Open Source Special Electrification Tool (OnSSET), Open Source Energy Modelling System (OSeMOSYS), RETScreen, which can also be used to conduct a techno-economic analysis of the proposed powers system. However, unlike these systems, HOMER software was designed to overcome the intermittency and the variability of power supply from renewable sources (Pavlovi et al., 2013). it provides insights into the complexities of renewables power output and trade-offs of designing cost-effective and reliable systems by simulating and optimising either a standalone or grid-connected

system comprising any combination of renewable energy technologies. (https://www.homerenergy.com/).
Despite the above advantages of using HOMER, the software has faced some criticisms from the academic literature. Sinha & Chandel (2014) argue that the HOMER software does not consider discharge depth in the battery storage system, variations in bus voltage, and intra-hourly variability. However, the HOMER software accounts for the timestep and daily variabilities in the load profile, and we have made provision for these variabilities in Table 3. Additionally, we have also documented how HOMER models the maximum power charge and discharge from the battery storage system in Appendix C.
From another perspective, Branker et al. (2011) noted that the LCOE does not consider the risks associated with financing capital intensive projects. Similarly, Okoye & Oranekwu-Okoye (2018) also argue that the LCOE does not answer the investor's question on the opportunity cost of investing in a particular project. Nonetheless, we do not find the above limitations of the HOMER software to significantly impact our analysis and the overall objective of this study.

Figure 6 illustrates the System Design.
Figure 6: Proposed mini-grid system design



Source: Authors' elaboration

3.3.1 Sensitivity Analysis

We assess the impact of the rapidly falling prices of renewable energy technology components on the LCOE using a projected 2030 cost reductions in mini-grid system components by ESMAP (2019). Also, we test the sensitivity of the LCOE to varying system reliability using capacity shortage (5% to 30%) and different discount rates (3% to 15%) to see if the results will influence the profitability of the project. We also consider different business models targeting either only residential, commercial or public service customers and assessed their respective profitability.

3.3.2 Modelling the energy flow and the LCOE of the project.

We discuss below the calculation of the energy flow and the simulation of the feasible system configuration components that feed into the financial model.

The PV+Battery system Model.
The PV+Battery system consists of a PV array, a battery storage system[6], and a converter[7] as illustrated in Figure 6. The model uses Equation 2 to simulates the PV array power output from a series of parameters, including the solar irradiance of Mafinga Town, temperature, degradation factor, PV module installation and system component specifications. Since we already have an estimate of the projected load profile of Mafinga Town, using Equation, we can determine the capacity of the PV module required to meet the load demand under normal circumstances. However, due to the intermittency and variability of solar power generation, HOMER oversize the PV module capacity to generate more power to make up for any shortfall in the power generation. Once the PV module's total capacity is determined, the software computes its total cost using the cost per kW in Table 1 and other system components costs to estimate the LCOE. We present the PV module's system optimised capacity in the LCOE result summary in Table 4 and the total net present cost and the annualised cost of the PV module in Table 7 in Appendix A.

Equation 2: PV array power output

$$P_{pv} = Y_{pv}\, f_{pv} \left(\frac{\bar{G}_T}{\bar{G}_{T,STC}}\right) \left[1 + \alpha_P \left(T_c - T_{c,STC}\right)\right] \qquad (2)$$

Where: Y_{pv} is the predicted average power output of the PV array under standard test conditions in kW, f_{pv} denote the derating factor of the PV array, $\bar{G}_T$ is the solar radiation incident on the PV array in the current time step expressed in (kW/m^2), $\bar{G}_{T,STC}$ represents the incident radiation at the standard test condition given as (1kW/m^2), α_P is the temperature coefficient of power expressed as (%/°C), T_c equals to the ambient temperature of PV cell, average throughout the test (°C), and $T_{c,STC}$ equals to the PV cell temperature of 25℃ under standard test condition. The temperature coefficient of power shows how strongly the power output from the PV array depends on its surface temperature. Some PV manufacturers do not specify the α_P in figures but represent it with a graph that may be challenging to determine. However, it is often around 0.004%/℃ for silicon PV modules and less for other PV technologies (Sandia et al., 2016). An amorphous silicon (a-Si) PV module is considered for this study. The a-Si PV module has a degradation rate of 87% per year to account for the panels' soiling, wiring losses, dust cover, and bird pollution (Sandia et al., 2016).

Battery Storage System
"The variability and intermittency of solar generation require a flexible storage system" (Hoarau & Perez, 2019). Therefore, to ensure the system's higher reliability, we consider a battery storage system consisting of several Lithium-Ion (Li-ion) batteries. Li-ion batteries have higher round-trip efficiency (97.5%) and a higher life span than lead-acid batteries. Li-ion batteries are relatively more costly than Lead-Acid batteries; however, because the battery's life-cycle cost accounts for 30% of the project's total capital cost, selecting a battery based on only its initial cost can be misleading and significantly impact the project's life-cycle cost. Thus, selecting a battery with a high degradation factor or shorter

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[6]Battery Storage System (BSS) a group of batteries connected using a series or parallel wiring to store the excess power generated from the solar PV.
[7] Converter (Inverter): a device that converts the direct current (DC) from the PV array to alternating current (AC)

life-span may require multiple replacements during the project lifetime, significantly increasing the LCOE. For instance, a study by the NREL for 20 cases of micro-grid systems operating for 20 years found micro-grids with Li-ion batteries to have a lower LCOE than those with Lead-Acid batteries (Lockhart et al., 2019). The above explains why we consider Li-ion batteries our study.

The Battery Storage System (BSS) Model

The model uses a combination of two independent factors, storage throughput[8] life and floats life[9] to estimate the life-span of the BSS, which enables the system to determine the when to carry out a replacement of the BSS.

It is worth noting that temperature is also a critical factor in battery degradation rate (Lockhart et al., 2019). The temperature at which a battery is kept has a strong bearing on the storage system's life span. According to Smith et al. (2017), batteries exposed to higher temperature often have a shorter life-span. Therefore, for the proposed project, we consider a battery maintenance system consisting of air conditioning, active air circulation, and direct evaporative cooling to control the batteries' temperature and improve the storage system's useful life. Lockhart et al. (2019) referred to this maintenance system as the heating, ventilation and air-conditioning (HVAC) configuration, which the Authors found to be very useful in prolonging a battery's life-span in SSA. However, it costs relatively more to implement the battery maintenance system's HVAC configuration; therefore, we consider \$20 per kWh as the battery maintenance cost, consistent with Lockhart et al. (2019).

The BSS model requires the following values to calculate the total cost of the BSS: the Battery initial and replacement cost (\$/kW), maintenance cost (\$/kW), the life-span of BSS (years) and BSS total capacity. HOMER uses a simulation optimisation technique to determines the optimal BSS capacity. The total BSS cost is another cost parameter used to estimate the LCOE for the PV+Battery system design. We present the storage systems' capacity in the LCOE result summary in table 4. Table 4 shows the BSS initial cost, and Table 7 in Appendix A shows the replacement cost and maintenance cost.

The life-span of the BBS is determined using the following Equation.

Equation 3: Life-Span of the Storage Bank

$$R_{batt} = MIN\left(\frac{N_{batt} \cdot Q_{lifetime}}{Q_{thrpt}}, R_{batt,f}\right) \tag{3}$$

Where R_{batt} is the BSS' life (yr.) , N_{batt} is the number of batteries in the BSS, $Q_{lifetime}$ is the lifetime throughput of a single battery (kWh), Q_{thrpt} *and* $R_{batt,f}$ represent the annual storage throughput (kWh/yr.) and storage float life (yr.) respectively.

It is not guaranteed that the battery storage system will absorb and store all surplus power output from the PV array for discharge during downtimes. Therefore, the system calculates the maximum power that the battery storage stem can absorb and then uses it to determine how much surplus power the generator should produce to meet the Hybrid System's load demand. This partly explains why the proposed project produces significant excess power and a relatively small capacity shortage, particularly for the PV + Battery System. The HOMER system uses the Kinetic Battery Model developed by Manwell & McGowan (1993) to estimate the amount of energy that the battery storage system can absorb or discharge at a given time step. Appendix C shows how the system determines the maximum power

[8] HOMER Energy defines throughput as the battery storage system's change in energy level, measured after charging losses and before discharging losses (www.homerenergy.com).

[9] Float life refers to the life expectancy of the battery storage system under continuous charging.

storage and discharge. Also, for further reference on modelling the maximum absorption and discharge of the battery storage system, see Hittinger et al. (2015) and Jongerden & Haverkort (2016).

Generator Model

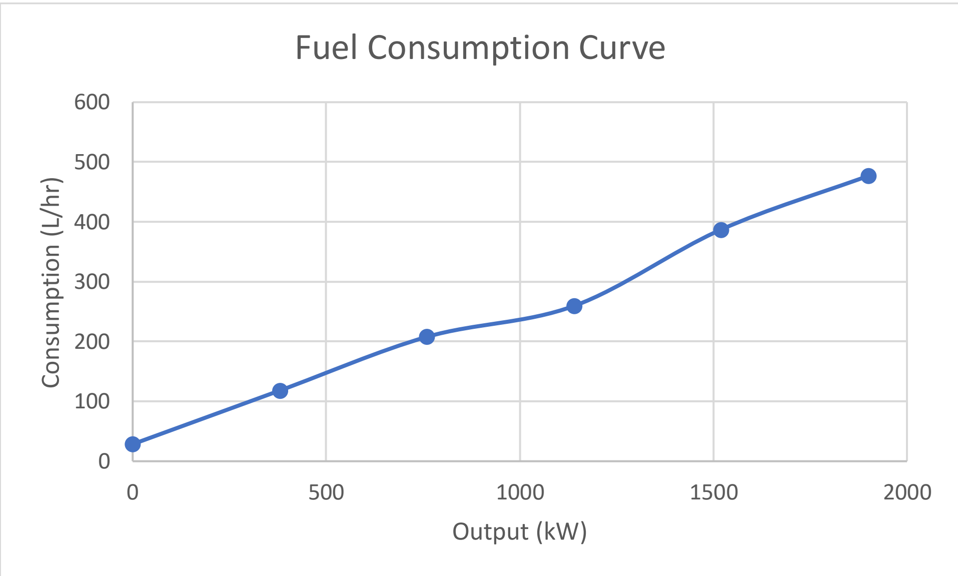
Following values are needed to model the LCOE for the diesel generator system design: the generator capacity, fuel consumption rate, generator efficiency rate, diesel cost ($/litre), generator life-span and operation and maintenance cost. The fuel cost is a significant cost parameter of the generator model, depending on the generator's fuel consumption curve. The fuel consumption curve is defined as the amount of fuel the generator consumes to produce a kilowatt-hour of electricity; thus, it is linearly related to the electrical output as expressed in Equation 4 and illustrated in Figure 7.

Equation 4: Fuel consumption curve

$$F = F_0 . Y_{gen} + F_1 . P_{gen} \tag{4}$$

where F denotes the total fuel consumption for each timestep, F_0 represents the non-load fuel consumption per kW by the generator (fuel curve intercept coefficient expressed in (units /hr/kW)), and Y_{gen} represents the rated capacity of the diesel generator (kW). F_1 is the marginal fuel consumption per kW of the generator output in each timestep (the fuel curve slope also expressed in (units /hr/kW)), and P_{gen} represents the electrical output of the diesel generator. For our proposed project, we use the system optimised F_0 = 32.4 L/hr and F_1 = 0.236, which give the fuel consumption curve calculated by Figure 7.

Figure 7: Fuel Consumption Curve



Source: Authors' elaboration

Modelling the life-span of the Generator

The life-span of the generator represents the generator's actual operational life (R_{gen}), after which a replacement is required. It is defined in Equation 5 as the lifetime hours of the generator ($R_{gen,hr}$) divided by the number of hours the generator operates during the year (N_{gen})

Equation 5: Operational life-span of the generator

$$R_{gen} = \frac{R_{gen,hr}}{N_{gen}} \tag{5}$$

The summation of the annualised fuel cost, generator initial and replacement costs, and OPEX divided the total electrical load served gives the LCOE for the generator model. We present the individual cost components in Table 7 of Appendix A and the generator's auto-sized capacity in Table 4 (LCOE result summary).

Modelling the LCOE

The LCOE is the total annual cost of installing, operating and maintaining the mini-grid system divided by the total electricity served to consumers. We use Equation 6 to calculate the LCOE

Equation 6: Levelized Cost of Energy

$$LCOE = \frac{C_{ann,tot}}{E_{served}} \tag{6}$$

Where $C_{ann,tot}$ is the total annualised system cost per year expressed in (\$/yr.). The E_{served} is the total electrical load served respectively. For our proposed system.

The Annualised Cost

As mentioned, the proposed mini-grid system has a life-cycle of 25 years, which implies that system components such as the battery storage system, converter and Genset will require replacements at particular times. Therefore, we assume a discount rate of 10% to translate all future cash flows of the project to present costs to estimate the proposed project's net present cost. This assumption is consistent with (Hittinger et al., 2015). A study conducted by Grant Thornton and the Africa Renewable Energy that surveys discounts rates of renewable energy projects in South Africa, Kenya, and Nigeria finds varying discount rates between 10% and 20% across the region (Grant Thornton, 2018).

The total annualised cost formula in Equation 7 converts the total Net Present Cost (NPC) of each system components into an annualised cost to estimate the LCOE per annum. It includes the PV array and convertor cost, the battery life-cycle cost, Genset and fuel life-cycle cost and the total operating and maintenance costs. The total NPC and annualised cost of each system components are present in Appendices A and B

Equation 7: Annualized Cost

$$C_{ann,tot} = CRF.\,C_{NPC,tot} \tag{7}$$

Where $C_{ann,tot}$ represents the total annualised cost, $C_{NPC,tot}$, is the total net present cost (\$),CRF is the capital recovery factor (the present value of an annuity) and it is defined in Equation 8 as:

Equation 8: Capital Recovery Factor

$$CRF = \frac{i(1+\ i)^N}{i(1+\ i)^N - 1} \tag{8}$$

Where: i and N represent the real discount rate and the number of years, respectively.

Data and Load estimation.

We obtain the local economic and techno-economic data from the Tanzania 2012 National Population Census, Tanzania mini-grid portal, World Bank Group and the National Renewable Energy Laboratory (NREL) publications. We obtain about two-thirds of the cost assumptions from the World Bank Group's publication on mini-grids market outlook (ESMAP, 2019). Table 1 shows the cost assumptions used in this study

Table 2: Cost assumptions of the input parameters

Assumptions	Base Case	Future Projections	References
Solar generation			
Installed PV cost [$/kW]	$230	$140	Estimated 39% cost reduction by 2030 (ESMAP, 2019)
PV O&M $/kW	$10	$6.1	
Useful life	25 years	25 years	
Battery storage cost [$/kWh]	$263	$95	Estimated 64% cost reduction by 2030 (ESMAP, 2019)
Battery useful life	15 years	15 years	
Battery O&M [$/kWh-installed]	$20	$10	
Converter costs [$/kW]	$115	$58	Estimated 50% cost reduction by 2030 (ESMAP, 2019)
Converter replacement cost [$/kW]	$58	$58	
Converter useful life	15 years	15 years	
Thermal generation			
Diesel genset cost [$/kW]	$500	$400	NREL and ASES (https://www.nrel.gov/)
Useful life	10 years	10 years	
Fuel cost [$/L]	$0.95/L	$0.95/	(EWURA, 2019b)
Fuel escalation rate	3%	3%	NREL and ASES
System fixed and operational cost			
Total distribution system costs	$160/client	$160/client	(ESMAP, 2019)
Smart Meters	$40/client	$30/client	
Pre-operating soft costs [$/kW]	$2'300	$2'300	(Reber et al., 2018) and NREL, (ESMAP, 2019)
Annual labour costs [$/year]	$38'000	$38'000	
Annual land lease costs [$/year]	$800	$800	

3.4 Electricity Demand Estimation

We rely on data from the following two sources to estimate the potential electricity demand from the five villages in Mafinga Town: (Ghosh et al., 2017); Williams et al., (2017). Ghosh et al. (2017) include case-studies of two mini-grids systems in Tanzania, of which the Mwenga mini-grid project is of comparable size as the proposed project, in terms of similar household types, commercial, community and agricultural activities. Likewise, the study by Williams et al. (2017) is based on case-studies of mini-grid projects in four different Tanzania communities, which exhibit similar daily load consumption reported by the World Bank report. The Rural African load profile tool simulates the hourly electrical load profile for various households and commercial entities commonly found in rural Sub-Saharan Africa. Thus, based on the data obtained from the world bank publication and validated with Williams et al. (2017), we used the Load profile tool to simulate the potential electricity demand for Mafinga Town. Table 3 presents the total estimated daily, yearly loads and the peak demand for the various consumer types in the five villages in Mafinga Town. The projected load profile for Mafinga Town is exhibited in Figure 8.

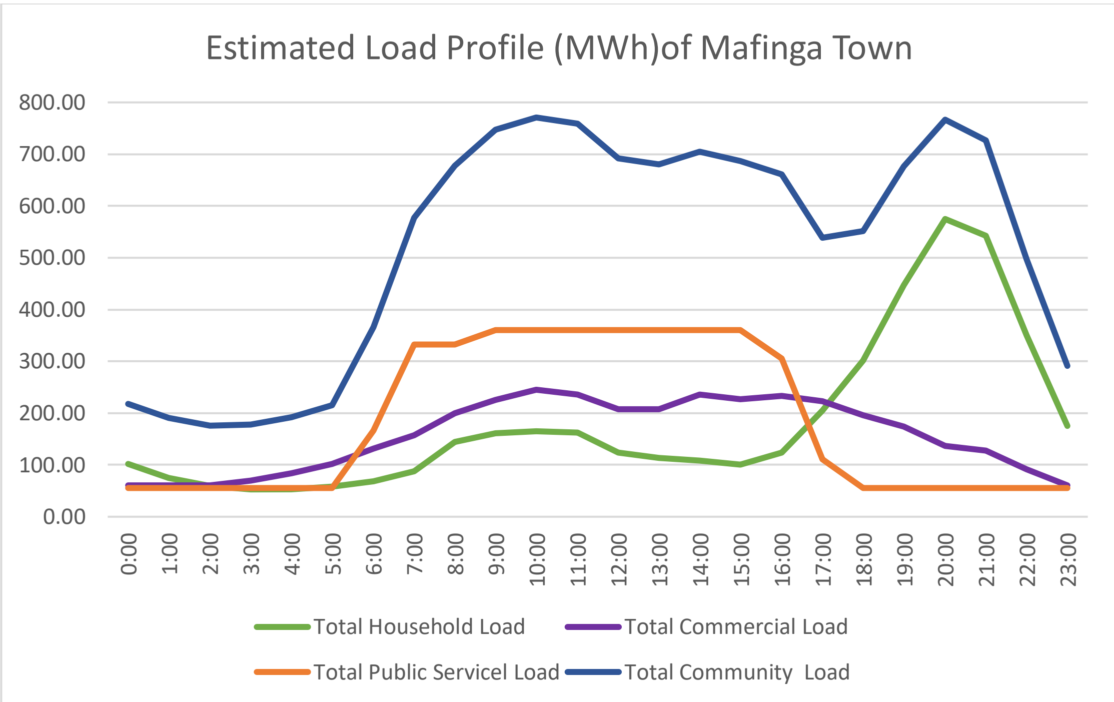
Following the works of Adaramola et al. (2017) and Williams et al. (2017), we expect that there will be some daily, monthly and seasonal vibrations in the daily electricity consumption and peak demand for the five villages. However, Williams et al. (2017) argue that the timestep and daily variabilities that the HOMER system estimates do not reflect the actual variabilities that micro-grid operators experience in East Africa. Besides, Hartvigsson & Ahlgren (2018) argue that overestimating or underestimating electrical loads' variabilities may significantly impact the system's technical and economic performances. Therefore, to minimise the potential error in our estimation, we use a timestep of 16% and daily variability of 20%, which is consistent with Williams et al. (2017) estimate for one of the micro-grids they studied in Tanzania that has similar load characteristics as the proposed system for the five villages. Additionally, we impose a reserve margin of 10% on all system design options to increase their reliability. The reserve margin is defined as the difference between the operable capacity and the peak demand in a particular year as a percentage of the peak demand (IRENA, 2013). Table 3 describes the load characteristics of the project.

Table 3: Load Profile Output Table

	Household Load	Commercial Load	Public Service Load	Total Community Load
Total MWh/day	4.36	3.75	4.44	12.55
Total MWh/year	1'591.40	1'368.75	1'620.60	4'580
Peak MW/day	0.57	0.25	0.36	0.77
Reserve Margin	10%	10%	10%	10%
Timestep variability	16%	16%	16%	16%
Daily Variations	20%	20%	20%	20%
Load Factor %	22%	27%	27%	31%

Source: Author's estimation

Figure 8: Estimated Load Profile of Mafinga Town



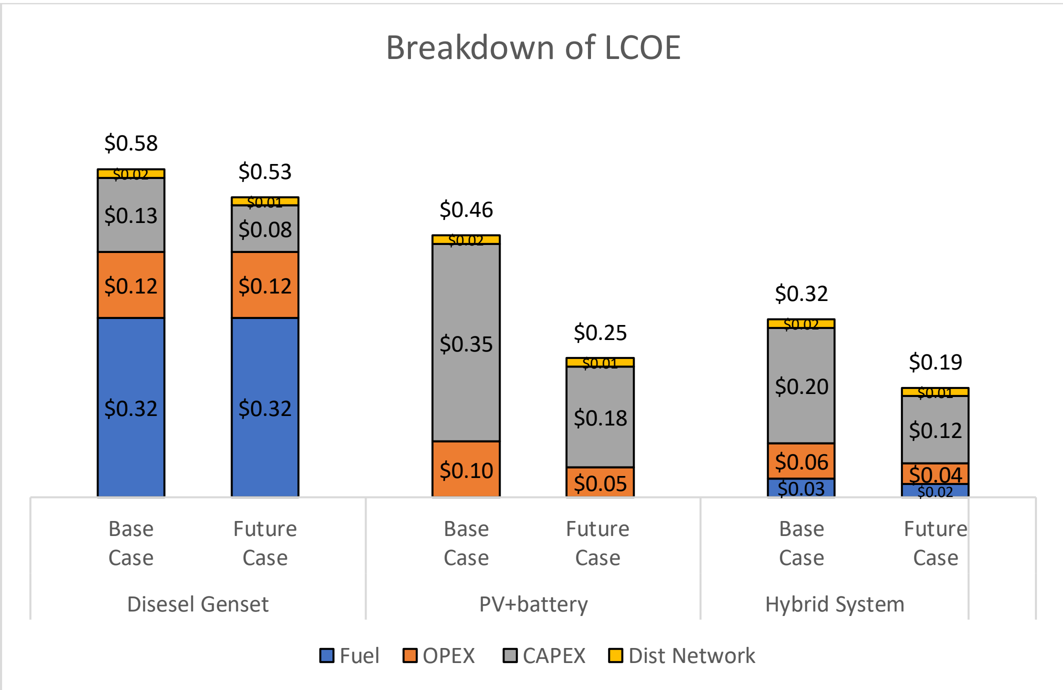
Source: Authors' estimation

4. Results

This section discusses the results of the HOMER model. First, we describe the general results and discuss how the estimated LCOE for the three system designs impacts the proposed mini-grid project's profitability. Second, we perform a sensitivity analysis of the LCOE using the 2030 cost projections of the system components and a combination of various discount rates and percentage of annual capacity shortages. Lastly, we discuss the policy implications of our results. Table 5 shows the possible system configuration results, such as the capacity of the various system components. It also includes the system cost summary and the LCOE for the three system designs. Table 6 also presents similar results for the sensitivity analysis using 2030 cost estimates. Figure 10 demonstrates the breakdown of the LCOE by system cost components.

The LCOE vary significantly from one technology option to another. The Hybrid System emerges as the most cost-effective solution with approximately 89% penetration of renewable energy generation (PV+ Battery) throughout the year. Its optimal system configuration is expected to generate 16.75 MW of electricity per day, approximately 22% more than the estimated load demand of 12.55 MW per day. It has a total life-cycle cost (net present cost) of $18.20 million and requires an electricity tariff of 32 cents to breakeven. The PV+ Battery System appears to be the second cost-effective solution, and compared to the Hybrid System, it will cost consumers extra 14 cents per kWh of electricity consumed. The PV+Battery system generates almost twice the projected electricity demand (23.17 MWh per day) to ensure high system reliability, indicating that the feasible system configuration is over-sized to make-up for the variability intermittency of the PV generation. The Diesel Genset option is the least cost-effective solution. Besides, it has a higher impact on the environment and produces about 4,067 tonnes of greenhouse gas emission per year. It also produces about 16% excess electricity to ensure high system reliability. The cost of fuel accounts for about half ($0.36/kWh) of the LCOE. However, under the PV + Battery and the Hybrid Systems, capital expenditure (CAPEX) emerge as the highest contributor to the LCOE and accounts for more than half of the LCOE (see Figure 9).

Figure 9: LCOE Breakdown



Source: Authors' elaboration

In that regards, we calculate the economic buoyancy vector of Mafinga Town. We find that Mafinga Town has a high economic buoyancy vector of 79%, which indicates low risks of consumer ability to pay for power consumed and productive use of power. Additionally, a satellite image accessible from a geospatial information system (GIS) provided by the EWURA also shows high commercial activities, including small industries, mini-supper markets, fuel filling station, schools, etc. Mafinga Town. These are essential indicators of wealth and consumers' potential to invest in clean energy; therefore, implying a low commercial risk for the proposed mini-grid project.

4.1 The Profitability of the Proposed Mini-grid System

The approved tariff for the proposed mini-grid project is approximately 10 cents per kWh, below the LCOE of the most cost-effective solution for the proposed project – the Hybrid System. The Hybrid system requires a minimum of 31 cents per kWh to recover its cost of investments. Thus, selling electricity at the current rate of 10 cents per kWh for the proposed mini-grid system will result in a loss of 21 cents on every kWh of electricity produced, which amounts to a total gross loss of $998,145 per year. Besides, EWURA approves an 18.5% return on equity for SPPs. Therefore, for the proposed mini-grid project to be financially sustainable, it must retail its electricity at a minimum rate of 38 cents per kWh, which implies that the project will require a subsidy of approximately $1 million per year to be financially feasible.

However, most of the subsidies for mini-grid projects in Tanzania were implemented between 2008 and 2014 (Org et al., 2016). Even if we apply the subsidies that used to be in place (Marching Grant and Performance Grant), they will not be enough to make the proposed project profitable. Both subsidies can only cover the distribution and the labour cost of the project, which will reduce the LCOE for the Hybrid System to 29 cents per kWh. It implies that the operators will still lose 19 cents per kWh on every electricity produced. Therefore, we argue that under the current tariff scheme in Tanzania, mini-grid projects are not financially viable from an investment perspective.

Table 4: LCOE Result Summary

	Diesel Genset	PV + Battery	Hybrid System
PV capacity	-	5,095 kW	2,849 kW
Battery (LA) capacity	-	24,122 kWh	10,625 kWh
Converter capacity	-	2,276 kW	1,460 kW
Diesel generator capacity	1,900 kW	-	1,900 kW
NP life-cycle cost	$33'495'760	$26'713'380	$18'186'120
Initial Capital cost	$1'837'100	$20'231'101	$11'922'078
Operating Cost	$2'518'502	$515'677	$498'315
LCOE	**$0.58**	**$0.46**	**$0.32**
Total emission/yr.	4,067,580 kg	0.00 kg	451,083.50 kg
SSP Tariff $/kwh	$0.10	$0.10	$0.10
Difference $/kwh	**-$0.48**	**-$0.37**	**-$0.22**
Annual Loss	**-$2'213'876**	**-$1'675'193**	**-$995'855**

4.2 Sensitivity Analysis

Although the Hybrid System emerges as the most cost-effective solution, the competitiveness of the PV+Battery system is highly influenced by parameters such as cost of capital, system reliability and capital investment cost. Therefore, given the rapidly declining cost of renewable energy technologies, we performed a sensitivity analysis on the LCOE for the three system designs using the 2030 cost estimates by ESMAP (2019), different discount rates from 3% to 15% and annual capacity shortages from 5% to 30%. Additionally, we also assess how different business models targeting residential, commercial, or public service consumers could impact the project's profitability.

2030 System Components' Cost Projection

We test the sensitivity of the LCOE to the 2030 system cost estimates and find that, as expected, the PV + Battery and the Hybrid Systems are highly sensitive to the 2030 cost estimates and has decreased significantly by approximately 49% and 39%, respectively. However, there was no significant change in LCOE for the Diesel Genset as a fuel price escalation rate of 3% offsets any possible decrease in the system cost.

Although the significant decrease in the LCOE for both the Solar+Battery and Hybrid Systems, the sensitivity analysis in Table 5 indicates that it is still not profitable to operate the proposed mini-grid system Mafinga Town. For instance, for the Hybrid System to be financially feasible by 2030, it requires a minimum electricity tariff of 24 cents per kWh to earn a return of 18.5% on its investments. However, if the operators are to sell electricity at the assumed rate of approximately 10 cents per kWh, it means that the operators would require a subsidy of $634,892 per year from the government. Similarly, if we apply the subsidies that used to be in place to the Future Case results, the LCOE for the Hybrid System will reduce to 17 cents per kWh. Again, this implies a significant loss of 9 cents per kWh on every electricity consumed.

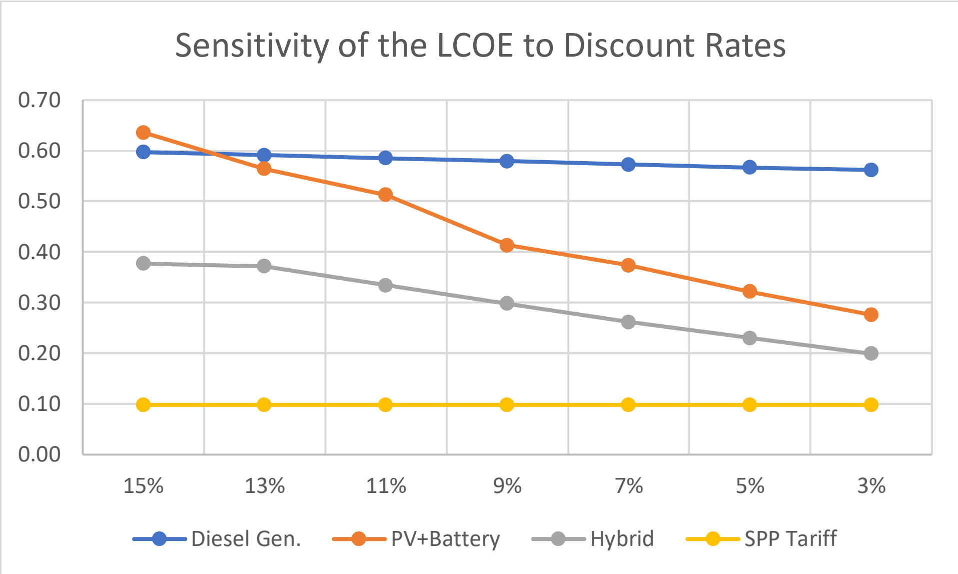
Table 5: LCOE Result Summary - Future Case

	Future Case Diesel Genset	PV + Battery	Hybrid System
PV capacity	-	4,344 kW	3,004 kW
Battery (LA) capacity	-	32,707 kWh	12,972 kWh
Converter capacity	-	2,349 kW	1,702 kW
Diesel generator capacity	1,900 kW	-	1,900 kW
NP life-cycle cost	$30'615'800	$14'191'200	$11'185'560
Initial Capital cost	$1'602'860	$10'711'328	$7'514'684
Operating Cost	$2'308'030	$276'830	$292'025
LCOE	**$0.53**	**$0.25**	**$0.19**
Total emission/yr.	4,067,580 kg	0.00 kg	649,684.50 kg
Avg. Nat. Tariff $/kwh	$0.10	$0.10	$0.10
Difference $/kwh	**-$0.43**	**-$0.15**	**-$0.10**
Annual Loss	**-$1'984'839**	**-$678'522**	**-$439'294**
LCOE @ 8%	$0.53	$0.21	$0.17
LCOE @ 15%	$0.55	$0.34	$0.26

Discount Rate and Capacity Shortage

Also, we assess the effects of different discount rates ranging from 3% to 15% on the LCOE. On the one hand, the result for discount rates lower than 10% show an increase in the NPCs and a corresponding decrease in the LCOE because the future costs were discounted a lower rate. On the other hand, the result for discount rates higher than 10% shows an opposite effect on the NPCs and the LCOE. Both the PV+Battery and the Hybrid Systems are more strongly impacted by the discount rates than the Diesel Genset. However, the changes in the LCOE are not significant enough to influence the profitability of the proposed system. Figure 9 illustrates the effects of the various discount rates on the LCOE.

Figure 10: The effect of Discount rates on the LCOE



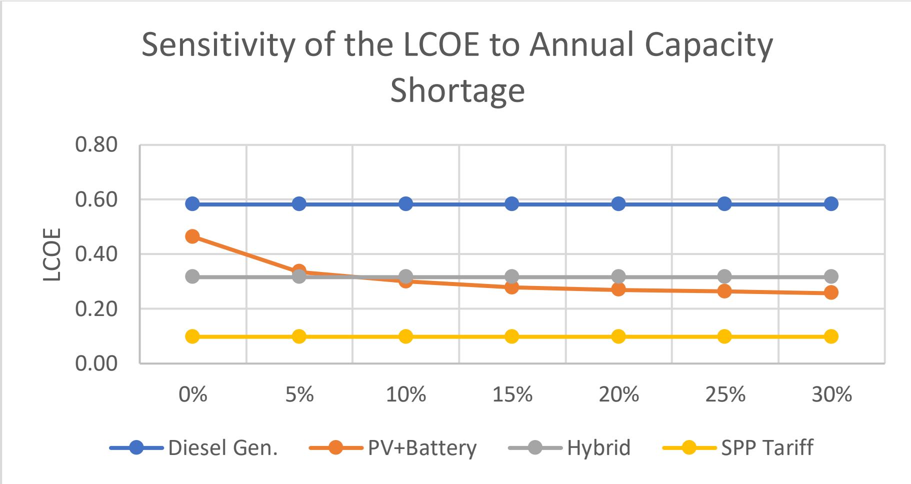
Source: Authors' elaboration

Capacity Shortage

As discussed earlier, the three system designs produce a significant amount of excess electricity of 16%, 46% 13% per year for the Diesel Genset, PV+Battery and the Hybrid Systems respectively, to ensure high system reliability. Therefore, we test the effect of system reliability on the LCOE using various percentages of annual capacity shortages from 5% to 30%. We find that the LCOE for the PV+Battery decreases significantly with an increasing percentage of annual capacity shortages of 5% to 15%, after which it experiences a minor decrease with further increase in the annual capacity shortage. Besides, from an annual capacity shortage of 10% upwards, the PV+Battery emerges as the most cost-effective solution with 16 cents per kWh decrease in the LCOE (from 46 cents to 30 cents). As part of the system configuration, an operating reserve of 10% is considered to make-up for any shortfall in peak load demand. Therefore, a capacity shortage of 15% implies an unmet electric load demand of approximately 5% – 10%, which means that the mini-grid system can only supply electricity to consumers for 22 hours per day at 28 cents per kWh. This appears to be the most efficient utilisation of the PV+Battery system since a further increase in the capacity shortage does not significantly impact the LCOE.

Nonetheless, even at this rate, it is not profitable to operate the proposed mini-grid project in Mafinga Town in Tanzania. The Diesel Genset and the Hybrid System were insensitive to the capacity shortage as both systems continue to produce enough electricity to meet the load demand even at an annual capacity shortage of 30%. Figure 10 demonstrates the sensitivity of the LCOE to the annual capacity shortage.

Figure 11: Sensitivity of the LCOE to Annual Capacity Shortage

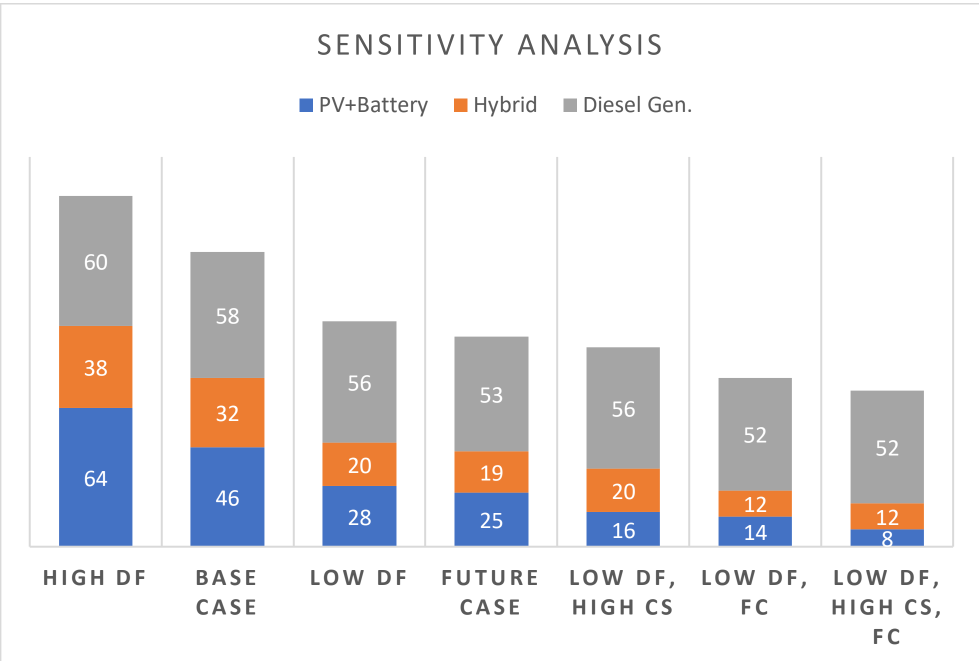


Source: Authors' elaboration

Combination of Discount Rate, Annual Capacity Shortage and 2030 cost estimates

Furthermore, we assess the effect of all the variables on the LCOE. We find that combining the three factors will deliver the lowest LCOE between 10 cents per kWh and 7 cents per kWh. However, this is an extreme case, which in the context of Tanzania, it is neither feasible now nor by 2030. This is based on the assumption that given the high investment risks associated with mini-grid projects in SSA, most private investors prefer to discount their future cash flows at the interest rates they anticipate receiving over the life of their investments (Williams et al., 2018, Grant Thornton, 2018). Thus, it is less likely for solar mini-grid projects to be discounted at the rate of 3% in SSA from an investment perspective. Therefore, this reinforces our argument that private commercial mini-grid projects in Tanzania purposely for rural electrification are not profitable even by 2030. Figure 12 illustrates the sensitivity of the LCOE to all three variables.

Figure 12: Sensitivity analysis using DF and CS for the 2030 cost estimates



Source: Authors' elaboration

In fig. 12, DF is Discount Rate, FC is Future Cost estimates, CS is Capacity Shortage. High DF = 15% and Low DF = 3%. High CS = 25% (about 18 hours of power supply per day)

Different business models

We analysed the project's profitability under different business models targeting either residential, commercial or public service customers from a different perspective. The results of our analysis are presented in Table 6. The results reveal that compared to the base case, which is based on a business model targeting the entire community, it is relatively more costly to install and operate any of the three mini-grid technologies to serve any individual customer type. It will cost approximately 38 cents per kWh under a business model using a Hybrid mini-grid system to serve only residential customers. This will result in a loss of about 28 cents per kWh on electricity sales.

Table 6: LCOE for different business models

Type of Load	Diesel Genset LCOE ($/kWh)	PV+Battery LCOE ($/kWh)	Hybrid LCOE ($/kWh)
Residential	0.761	0.513	0.377
Commercial	0.703	0.492	0.348
Public Service	0.690	0.480	0.335

5. Conclusion and Policy Implication

This study is motivated by the desire to understand the financial sustainability of mini-grid systems in Tanzania. The exercise allows us to understand further the future pathway for increasing electricity access in rural SSA and help design policy interventions to leverage development partners' funding and crowd in private financing of mini-grid projects.

Our analysis shows that despite a well-structured mini-grid tariff system and subsidies initiatives in Tanzania, operating privately-owned mini-grid systems in rural communities is not financially sustainable. Further, we describe some of the challenges with the effective deployment of mini-grid systems in Tanzania up to the scale required to attain universal access to electricity by 2030. Specifically, we highlight non-cost-reflective tariff for mini-grid projects and the commercial risk of mini-grid projects as significant challenges facing the commercial deployment of mini-grid systems in Tanzania. Therefore, the government may consider the followings. Firstly, EWURA may want to review its tariff scheme for mini-grid developers to reflect the cost of production and electricity supply from an off-grid system to serve isolated rural communities. This is particularly important because it appears the current tariff scheme is based on mini-grids systems connected to the grid. Meanwhile, the grid-connected mini-grids enjoys significant trade-offs between buying unmet load from the grid and selling excess load to the grid and oversizing the system to ensure system reliability. This option is rarely available to off-grid developers except for the latter, which is considerably more expensive.

Secondly, the argument in the body of literature for policy intervention has focused mainly on subsidies. However, it is worth noting that in the case of Tanzania, for the proposed project to be profitable, it requires a subsidy of about $1 million per year for twenty-five years under our base case scenario. This, we argue, may be difficult to implement sustainably and efficiently given that there may be several similar projects across the country requiring a similar amount of subsidy. Alternatively, we make a case for the importance of empowering rural community people with income-generating activities to enable them to pay for the cost of power. By providing people with decent income-earning opportunities, the government will, at the same time, be addressing the commercial risks associated with rural mini-grid projects as well as the high prevalence of poverty associated with rural people.

Thirdly, given the Hybrid and PV+Battery systems' high initial capital requirement, the government may consider expanding its loan facilities to enable private developers to access adequate funding for their projects at a considerably low rate.

Lastly, as pointed out earlier, the Hybrid System appears to be the most cost-effective solution under our base case scenario. However, with an annual capacity shortage of 15%, the PV+Battery system instead emerges as the most cost-effective solution for providing electricity at the rate of 28 cents per kWh (approximately 40 percent decrease in LCOE). In this regard, we recommend that private developers consider complimentary solutions such as Solar Home Systems to make-up for the capacity shortage if necessary.

The paper also identifies some valuable lessons from the mini-grid regulatory and policy regime in Tanzania that may be worth emulating by other SSA countries of similar context. First, the establishment of a specific policy to regulate the development and operations of SPPs. This includes the implementation of the technology-specific and size-specific standardised SPPA and SPPT. However, the SPPA and SPPT must be cost-reflective to enable private mini-grid systems and developers to recover their cost and earn adequate investments. Second, the establishment of a financial support scheme for rural mini-grid developers. However, we suggest the government expand its loan facility to enable local and other private developers access funding at an affordable rate for their project. We also recommend that the government consider investing subsidies in developing economic activities in rural communities to empower consumers financially to pay cost-reflective tariffs. Third, establishing a comprehensive mini-grid information portal and a geospatial portfolio planning tool is particularly important in reducing pre-site costs.
The above critical lessons from Tanzania demonstrates the government's commitments to establishing an enabling business environment which are critical success factors in leveraging development partner funding and a few private sector developers.
A further study is required to identify successful business models and strategies to improve mini-grids profitability from a research perspective. Particularly to identify opportunities to combine mini-grids with main grid extension and develop new business models that leverage these technologies' combination to deliver affordable electricity in high energy access deficit countries.

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Appendices A: Base Case Cost Summary

Table 7:Cost Summary - Hybrid System

HYBRID SYSTEM						
Net Present Cost						
Name	CAPEX	OPEX	Replacement	Salvage	Fuel	Total
Genset	$950'000	$741'593	$398'506	-$58'376	$1'930'000	$3'961'723
Li-Ion Battery	$2'790'000	$2'000'000	$430'367	-$54'588	$0	$5'165'779
PV Array	$7'120'000	$358'140	$0	$0	$0	$7'478'140
Converter	$167'938	$0	$34'466	-$6'309	$0	$196'095
System FC & VC	$887'100	$487'733	$0	$0	$0	$1'374'833
Annualised Cost						
Genset	$75'574	$58'995	$31'702	-$4'644	$153'463	$315'090
Li-Ion Battery	$222'297	$159'375	$34'236	-$4'343	$0	$411'565
PV Array	$566'620	$28'491	$0	$0	$0	$595'111
Converter	$13'360	$0	$2'742	-$502	$0	$15'600
System FC & VC	$70'570	$38'800	$0	$0	$0	$109'370

Table 8: Cost Summary - PV+Battery

PV + BATTERY					
Net Present Cost					
Name	CAPEX	OPEX	Replacement Cost	Salvage	Total
Li-Ion Battery	$6'340'000	$4'550'000	$932'487	-$170'684	$11'651'803
PV Array	$12'700'000	$640'495	$0	$0	$13'340'495
System Converter	$261'785	$0	$53'726	-$9'834	$305'677
System FC & VC	$887'100	$487'733	$0	$0	$1'374'833
Annualised Cost					
Li-Ion Battery	$504'683	$361'830	$74'181	-$13'578	$927'116
PV Array	$1'010'000	$50'953	$0	$0	$1'060'953
System Converter	$20'825	$0	$4'274	-$782	$24'317
System FC & VC	$70'570	$38'800	$0	$0	$109'370

Table 9: Cost Summary - Diesel Genset

DIESEL GENSET
Net Present Cost

Name	CAPEX	OPEX	Replacement	Salvage	Fuel	Total
Genset	$950'000	$6'280'000	$6'700'000	-$85'264	$18'300'000	$32'144'736
System FC & VC	$70'570	$38'800	$0	$0	$0	$109'370
Annualised Cost						
Genset	$75'574	$499'263	$532'964	-$6'783	$1'450'000	$2'551'018
System FC & VC	$70'570	$38'800	$0	$0	$0	$109'370

Appendix B: Future Case Cost Summary

Table 10: Cost Summary - Hybrid System

HYBRID SYSTEM						
Net Present Cost						
Name	CAPEX	OPEX	Replacement	Salvage	Fuel	Total
Genset	$760'000	$504'426	$158'926	-$105'289	$1'330'000	$2'648'063
Li-Ion Battery	$1'230'000	$897'058	$184'791	-$33'824	$0	$2'278'025
PV Array	$4'580'000	$226'539	$0	$0	$0	$4'806'539
Converter	$98'706	$0	$20'083	-$3'676	$0	$115'113
System FC & VC	$842'860	$487'733	$0	$0	$0	$1'330'593
Annualised Cost						
Genset	$60'459	$40'128	$12'643	-$8'376	$106'131	$210'985
Li-Ion Battery	$98'057	$71'362	$14'700	-$2'691	$0	$181'428
PV Array	$364'386	$18'022	$0	$0	$0	$382'408
Converter	$7'852	$0	$1'598	-$292	$0	$9'158
System FC & VC	$67'051	$38'800	$0	$0	$0	$105'851

Table 11: Cost Summary - PV+Battery

PV+BATTERY					
Net Present Cost					
Name	CAPEX	OPEX	Replacement Cost	Salvage	Total
Li-Ion Battery	$3'107'165	$465'816	$2'261'276	-$85'264	$5'748'993
PV Array	$6'625'056	$0	$327'658	$0	$6'952'714
System Converter	$136'247	$27'721	$0	-$5'074	$158'894
System FC & VC	$842'860	$487'733	$0	$0	$1'330'593

Annualised Cost					
Li-Ion Battery	$247'180	$37'057	$179'889	-$6'783	$457'343
PV Array	$527'035	$0	$26'066	$0	$553'101
System Converter	$10'839	$2'205	$0	-$404	$12'640
System FC & VC	$67'051	$38'800	$0	$0	$105'851

Table 12: Cost Summary - Diesel Genset

DIESEL GENSET						
Net Present Cost						
Name	CAPEX	OPEX	Replacement	Salvage	Fuel	Total
Genset	$760'000	$6'280'000	$4'020'000	-$51'158	$18'300'000	$29'308'842
System FC & VC	$842'860	$487'733	$0	$0	$0	$1'330'593
Annualised Cost						
Genset	$60'459	$499'263	$319'778	-$4'070	$1'450'000	$2'325'430
System FC & VC	$67'051	$38'800	$0	$0	$0	$105'851

Appendix C: Modelling Storage Bank's maximum power absorption and discharge

Storage Bank's maximum power absorption and discharge
Using the Kinetic Battery Model, the system calculates the Battery's maximum power storage and maximum power discharge.

Figure 13: A Two-tank Kinetic Battery Model Concept

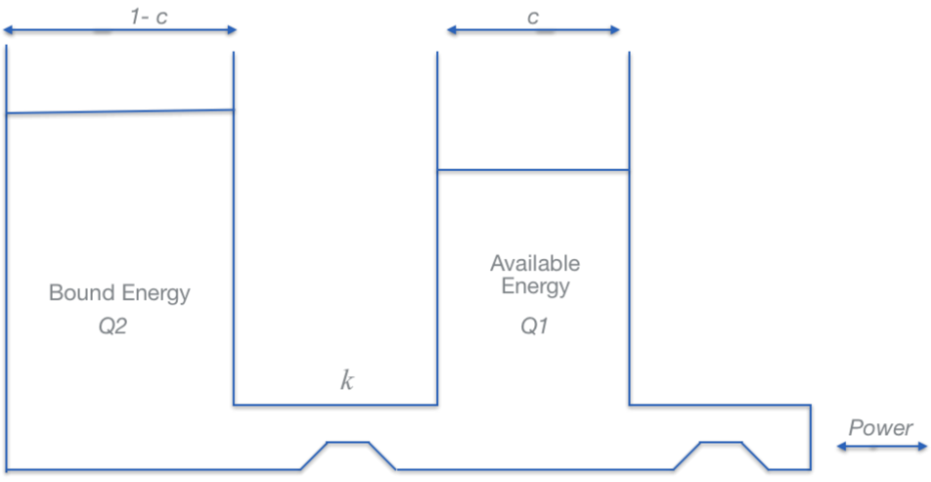

Figure 8, (c) is a fraction of the total capacity of the storage bank in the available energy tank and (1-c) is the fraction of the total capacity of the storage bank in the bound energy tank.
The following three parameters are considered to determine the Battery's maximum power storage and maximum power discharge.

Maximum storage capacity (Q_{max}): the sum of the available energy (electrical energy) and bound energy (chemical energy).
The Capacity ratio (c): this parameter denotes the rate at which the charge energy flows between the available energy tank and the bound energy tank. It is, therefore, represented as the ratio of the available energy tank to the combined size of both tanks.
The fixed Conductance (k): This parameter has a dimension of 1/time, which is a measure of the rate at which bounded energy is converted to available energy and vice versa.
The storage bank's maximum power absorption over a given period ($P_{batt,Cmax,kbm}$) is determined using Equation 9
Equation 9:

$$P_{batt,Cmax,kbm} = \frac{kQ_1 e^{-k\Delta t} + Qkc(1 - e^{-k\Delta t})}{1 - e^{-k\Delta t} + c(k\Delta t - 1 + e^{-k\Delta t})}$$

Similarly, the storage bank's maximum power discharge over a given period ($P_{batt,dmax,kbm}$) is determined using Equation 10
Equation 10

$$P_{batt,dmax,kbm} = \frac{-kcQ_{max} + kQ_1 e^{-k\Delta t} + Qkc(1 - e^{-k\Delta t})}{1 - e^{-k\Delta t} + c(k\Delta t - 1 + e^{-k\Delta t})}$$

WORKING PAPER

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