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Solar-PV-Based Mini-grids in Rural Areas of Developing Countries: An Economic Evaluation of Two Real-World Case Studies in West Africa

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ABSTRACT

This study evaluates the sustainability of solar PV-based mini-grids for rural electrification in developing countries. A discounted cash flow method is used to compare the economic feasibility of a real-world solar-mini-grid and a diesel-fueled mini-grid located in West Africa and the subsidy needs of the two projects. It is found that both mini-grids currently need high subsidies due to demand stimulation problems and high distribution losses. Still, the results provide evidence that PV-based mini-grids are already economically feasible without subsidies if they are located in customer environments with an ability to pay (ATP) greater than 0.57 €/kWh (assuming soft loans, stimulated utilization rates as well as hardware cost decrease). The approach and findings are especially useful for mini-grid developers/operators and investors with a focus on rural electrification projects. This study further identifies cost reduction potentials by means of demand stimulation in green mini-grids.

Keywords: mini-grid, solar PV, diesel, subsidization, ability to pay, development bank loans, West Africa

NOMENCLATURE

Abbreviations

ATP	Ability to pay
CAPEX	Capital expenditures
DCFM	Discounted cash-flow method
DMG	Diesel-fueled mini-grid
EU	European Union
LCOE	Levelized cost of electricity
O&M	Operation & maintenance
OPEX	Operating expenditures
SMG	Solar photovoltaic mini-grid
T_{PV}	Service lifetime of solar PV plant
TOU	Time of use
TTA	TramaTecnoAmbiental (company)
UR	Utilization rate

Symbols

AAC	Average annual consumption (of el.)
CAPEX	Capital expenditures
d	Percentage of degradation
$e_{s,t}$	Amount of energy sold in period t
i	Interest rate, internal rate of return
i_r	Risk-adjusted interest rate
Inv	Investment cost
NPV	Net present value
O&MC	Operating & maintenance costs
$p_{e,t}$	Energy price in period t
PVO	Output of the photovoltaics plant
T	Project lifetime
t	Time
UR	Utilization rate
z	Sum of cash inflow and outflow

1. INTRODUCTION

According to the World Bank, mini grids are the least-cost option for rural electrification. Their profitability depends on local conditions such as the community size, population density, distance to the national grid, geographic factors, and socio-economic factors [1] (p. 56). While national grid extension involves high cabling costs, mini-grids are the preferred solution for dense communities in rural areas [2] (p.1).

This paper carries on to these prior findings and investigates the profitability of off-grid power stations by applying the net present value (NPV) method. The model-based analysis is based on real site data of a solar-PV-based mini-grid (SMG) and a diesel-fueled mini-grid (DMG) provided by TramaTecnoAmbiental (TTA), a developer of renewable energies. Both mini-grids are located in a country in West Africa and operate under similar climate conditions. With the help of the site-specific data, this report answers the question of whether SMG investments in the rural areas of developing countries are economically feasible or if they require subsidies. Furthermore, the goal is to create informative results based on real-site data of the SMG and the DMG in West Africa.

The report explains how this information is inserted into the proposed financial model. Furthermore, it explains the approaches of the following investigated scenarios: (1) Subsidy scenario; (2) No-subsidy scenario; (3) Unit economic analysis; (3) Hard-cost decline scenario; (4) Demand stimulation scenario.

2. METHOD USED

Discounted Cash Flow (DCF) analysis is a dynamic investment calculation method to estimate the financial feasibility of a project using dynamic cash flows. The objective of the DCF method is to determine the increase in net assets resulting from project implementation. This increase in net assets is called Net Present Value (NPV). The NPV can be described as the price of an investment opportunity on the capital market. The DCF calculation is based on the assumption that the cash inflow value decreases the quicker the larger the time difference is to today. In the case of a present-day cash inflow, the capital can be used to invest in projects with a positive return. Applying an interest rate i, the amount of money after a time period t would be higher by the factor $(1+i)^t$ [3] (p.39). In contrast, if a cash inflow happens in a future time period t, opportunity costs arise and discounting with the factor $1/(1+i)^t$ lowers the present value (ibid., p.40). The opportunity costs arise due to the fact that the actually invested money could be invested in other projects which have an equal or even higher internal rate of return i.

The longer the time until the cash inflow happens, the larger is the negative impact on the NPV caused by the compound interest effect. Regarding the cash inflow in period 2, alternatively, the capital could have been invested at an interest rate i in period 1 and as well in period 2 including the revenue of the investment in period one. Therefore, the opportunity costs per monetary unit rise exponentially.

$$NPV = -Inv_0 + \sum_{t=1}^{T} \frac{z_t}{(1+i)^t} \qquad (1)$$

Eq. (1) displays the general equation to calculate the NPV. T stands for the project lifetime. The investment cost at the beginning (denoted Inv_0) has a negative sign because its cash outflow has a negative impact on the NPV. The cash flow per period z_t is the sum of the cash outflow and the cash inflow. An investment is financially feasible when $NPV \geq 0$. Replacing general variables with the specific ones for mini-grids allows the transformation to a DCF equation for SMG systems (see Eq. (2)).

$$NPV = -CAPEX + \sum_{t=1}^{T_{PV}} \frac{(e_{s,t} \cdot p_{e,t}) - O\&MC_t}{(1+i_r)^t} \qquad (2)$$

The upfront investment is replaced with the capital expenditures (CAPEX) for solar PV panels, batteries, and more (see Subsection 3.1.2). Due to the high investment costs and long time of use (TOU), the service time of the solar panels, T_{PV}, sets the project lifetime in most of the scenarios. The amount of energy sold in period t ($e_{s,t}$) multiplied with the energy price in period t ($p_{e,t}$) results in the revenue of period t. The revenue in period t subtracted with the operation & maintenance costs (O&MC) in period t represents the general cash flow variable z_t used above. Finally, the risk-adjusted interest rate i_r includes a risk premium to account for possible project failure or unsustainability. The higher the risk of an investment is, the higher is the risk premium lenders will request to compensate potential losses. This investigation estimates a risk premium for the SMG investment of 1% and 2% for the DMG (see section 3.1.5).

An interest rate of 3% is used to relate to a World Bank's loan. SMG investments suffer from low cash values in the last periods due to the discounting with the exponential time factor. Assuming a risk-corrected interest rate of 4%, the cash value for a cash inflow z_t in year 30 is $z_t/(1.04)^{30}$. As a result, the cash value in year 30 is only 30.8% of the cash inflow.

Figure 1 illustrates this exponential effect on the cash value progression. It compares cash values of cash flows with two different interest rate levels. For better comprehensibility, the graph considers the cash flow starting from year 1 as constant and positive (inflow).

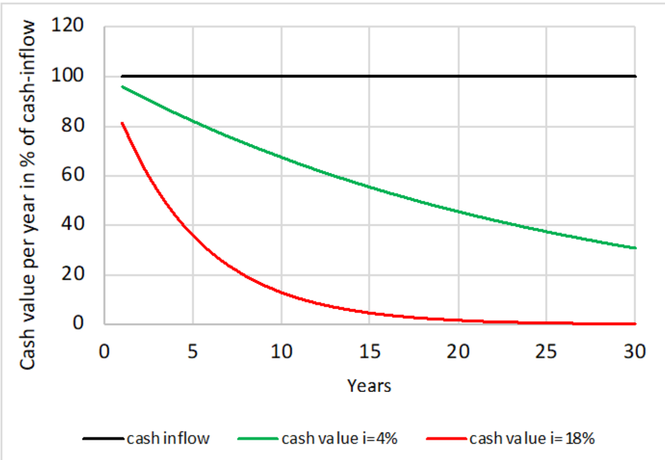

Fig. 1. Cash value over time for different interest rates

The green line represents the cash value progression, applying the 4% risk-corrected interest rate used in our study. The red line represents the cash value progression, applying an interest rate of 18%, which is a commonly used value for the private sector according to [4] (p.176). For a better comparison, the black curve illustrates a non-discounted cash inflow corresponding to the actual cash inflow per year. The following is observed: the higher the interest rate the higher is the negative exponential impact on the cash value due to discounting. Because of the fact that the NPV is the sum of the individual cash values in each period, the result whether the investment is sustainable or not is exponentially influenced by the chosen interest rate.

Fig. 2 shows a simplified cash flow stream of a SMG for the project's entire lifetime. Two assumptions are made to improve clarity [5] (p.140). Firstly, the figure assumes a constant number of customers with a constant demand for electricity. Secondly, it assumes a battery replacement every 10 years. In the year of installation (year 0), it is not possible to sell energy and no operational costs appear. Therefore, the cash flow in year 1 is only determined by the upfront investment (CAPEX), marked with a red cash outflow arrow. The green cash inflow arrows are related to revenues of the electricity purchase and decrease as the time of use elapses. Therefore, the revenues of electricity purchases and the cash inflow decrease simultaneously.

In reality, demand is varying strongly, and diesel generator sets usually compensate for shortages in the electricity supply of SMG to maintain the required voltage level of the grid. During the operation of the SMG, only operation & maintenance costs (O&MC) determine the cash outflow. Solar PV energy generation does not rely on external material energy supply like diesel generators, which keeps the operational costs relatively low. Hence, battery replacements constitute the largest cash outflow after the initial investment. Note that expenditures for disposal at the end of the project are not considered in this illustration.

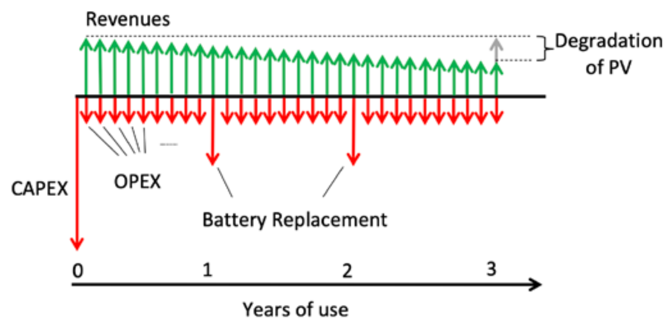

Fig. 2: Simplified cash flow for SMG investments

Furthermore, the determination of the exact amount of electricity consumed per time period has a significant impact on the feasibility study. The approach used for the two mini-grid cases of TTA is represented in Eq. (3). The maximum PV output (PVO_{max}) is constant during the project's lifetime. Multiplied with the degradation losses per year $(1–d)^t$, and divided by the years of lifetime, the actual amount of generated electricity can be calculated. Finally, including the utilization rate (UR) reveals the average annual consumption value, *AAC*, which is used in the demand stimulation scenario (cf. Section 4.7).

$$AAC = \frac{\sum_t^T PVO_{max} * (1-d)^t}{T} \cdot UR. \qquad (3)$$

3. DATA AND ASSUMPTIONS

Both mini-grids studied operate in the same country, rather close to each other, and have a similar number of customers, which are useful prerequisites for a direct economic comparison. To achieve comparable results, the study only considers data available from similar seasons. Hence, the analyzed time period ranges from the beginning of December 2017 to the end of June 2018. In the following, we describe how the model is applied to the two different cases and present the data used for each case in the DCF model calculations. They provide deep insights into site-specific data and the on-site framework.

Note that this investigation neglects differences in irradiation and temperature levels due to the fact that the operations are located close to each other. The mentioned climate factors have a strong influence on the electricity output of solar panels and hence also a strong impact on the economic viability of the mini-grids.

3.1 Inputs

3.1.1 Time of use

Direct information about the lifetime of the boat motor used in the DMG is not available. To apply realistic data to the model, the analysis makes use of values from the literature. According to the Rocky Mountain Institute, the lifetime of a hybrid mini-grid system amounts to 20 years using a diesel generator including one replacement [6] (p.18). Applying this value in our investigation, the calculations estimate 73,000 h of operation with 10 h of operation per day (from 8 pm to 6 am) including one replacement.

The type of solar panels used by the SMG is unknown and the use of polycrystalline solar cells is expected. Following the majority of literature, this study applies an optimistic PV lifetime of 30 years [7] (p. 199).

3.1.2 CAPEX

Because of the facts that the system uses an old diesel motor and no cost data from TTA is available, the CAPEX for the DMG cannot be determined exactly. With the objective to calculate a representative LCOE for the DMG, benchmark values are used for the time of utilization. The analysis assumes the cost of the diesel generator including its housing and replacement at 1.050 US$/kW of generation power (Ibid.). This value corresponds to 930 €/kW. Applying these values to the 396 kW boat motor, the investment for the diesel generator amounts to €415,800. Based on benchmark data of the Rocky Mountain Institute, further project development costs of €115,575 and distribution costs of €80,800 are assumed. These project development costs include duties and fees, installation costs as well as soft costs. The distribution costs consist of the cost for cabling and the cost for connections. To get this result, the calculation assumes a network with 3 kilometers of cabling, specific costs of €1372 per 100 m of cabling, as well 700 connections with connection costs of €43 per unit (smart meters are not included; [6] (p.18). Finally, the total CAPEX of the DMG amount to €612,175 and can be inserted in Eq. (2).

The total CAPEX for the SMG including installation costs amount to €2.93 million, using the same cost structure as proposed in [8]. With 312 kilowatt peak (kW_p) installed PV power, the total investment cost per generation power installed amounts to €9411 per kW_p. With 34% the project development costs take the highest share, followed by generation (22%), storage (16%) and distribution (16%). This distribution is uncommon, as typically the generation or storage category represents the biggest share of the CAPEX [9].

3.1.3 OPEX

The estimated annual OPEX of the investigated public DMG for the year 2019 amounts to €251,796, of which fuel costs account for about 85%, staff costs for 14%, and engine oil for 1%. To calculate the profitability of the system, the average annual OPEX of 2018 are assumed to be constant over the entire lifetime of the system. However, due to the high dependency on fossil fuels, the consideration of the diesel price development is important for the feasibility study of such an investment. A more detailed profitability investigation in the future should take recent diesel price developments into account. Repair costs related to the grid infrastructure are not considered.

As fuels are not required for the SMG, OPEX remain comparably low. The average yearly OPEX for personal costs, usage costs, and security amount up to €20,354. With a share of 70%, staff costs dominate while costs for security and rental material stay around 15% respectively. Costs for financial services are neglected.

3.1.4 Price per kWh/ Tariff

The municipal utility in town D uses a decreasing block tariff for pricing the generated electricity (Table 1). 90.2% of the connections are private households. The average consumption of a private household in town D amounts to 40.83 kWh per month. Due to their low consumption, the municipal utility charges the highest tariff (0.76 €/kWh) to most of the customers. Therefore, the average price per electricity amounts to 0.74 €/kWh. In order to determine the price per unit of energy in period t ($p_{e,t}$) for the DCFM, the average price per unit of electricity is applied and it is assumed to be constant over the project's lifetime. Even though fluctuations of electricity consumption are likely to impact the average unit price of electricity, this influence is ignored for simplicity.

TTA uses two types of linear tariffs for the customers of the SMG while applying a prepayment system to reduce revenue collection losses. Households are charged with the normal tariff of 0.49 €/kWh whereas public institutions pay the social tariff of 0.39 €/kWh. With the available consumption data, it is possible to determine a representative average of the electricity price which is 0.48 €/kWh.

Figures 3 and 4 reveal the number of active connections of both mini-grids. Active connections in this context are connections with consumption higher than 1 kWh per month.

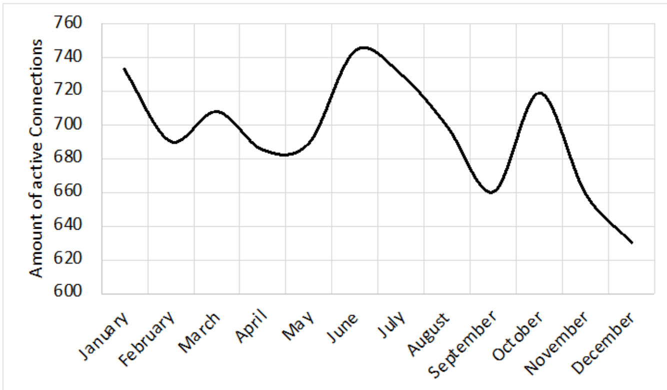

Fig. 3. Active connections in the DMG (2018, town D)

Table 1. Decreasing block tariff scheme used in town D

Electr. consumption [kWh p.m.]	Electricity price [€/kWh]
0–30	0.76
31–50	0.61
> 50	0.53

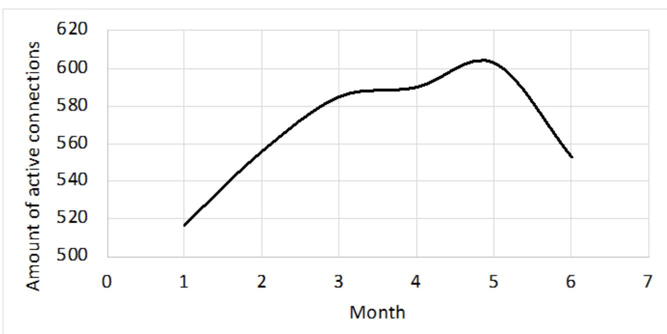

Fig. 4. Active connections in the SMG (1-6/2018, town S)

3.1.5 Interest rate

Although the government runs the DMG, this feasibility study assumes a private operation to build a base for comparison with the SMG. Therefore, the interest rate is similar to one applied to the SMG in town S. It is based on privately financed capital coming from international development banks like the World Bank. For this reason, an interest rate of 3% is applied to the DCFM. Unlike the SMG, the economic viability of the DMG depends strongly on the diesel price. Operators have no influence on the major OPEX share and so the future development cannot be determined exactly. The consequence is an increased investment risk for potential investors. For this reason, the DCFM applies a comparably high risk premium of 2%.

For the SMG the same interest rate of 3% is applied. Additionally, a risk premium of 1% is added to consider political, regulatory, and revenue collection risks.

3.1.6 Utilization rate estimation

Further on, an assumption for the utilization rate during the lifetime of the project is applied (Fig. 5). This assumption is based on [6] (p.44). Since a UR of 100% seems unrealistic, a lower UR with a maximum value of 85% is assumed. The aim is to calculate the LCOE under realistic demand changes. The calculation is based on the following approach.

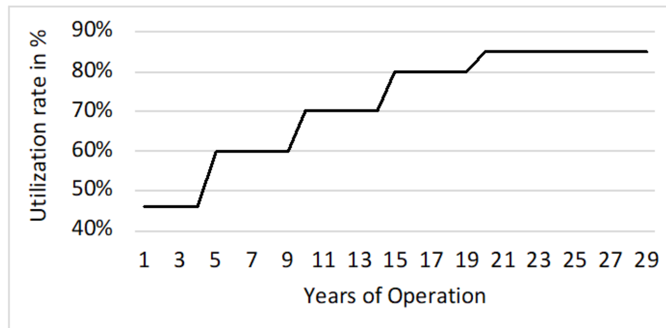

Fig. 5. Utilization rate development assumed

3.1.7 Hard cost fall simulation for the SMG

The hard cost fall simulation evaluates the effect of the estimated cost fall for SMG components. According to the Rocky Mountain Institute, hard costs for mini-grids are estimated to decline about 18% within three years. This study applies a less optimistic decline of 3% per year, estimating the costs for generation, batteries, and conversion components in 2021 to be 21% cheaper compared to 2014.

4. RESULTS (DMG AND SMG, BY SCENARIO)

4.1 Subsidy scenario DMG

Applying the assumptions to the DCFM described above, the NPV under current conditions is negative at €-633,455. Therefore, an investment in a DMG with those characteristics will lead to a capital loss of €633,455 after the 20 years of system lifetime have elapsed, and subsidies in the same amount are required to run this DMG without making losses. It is surprising that the cash flow is negative for every year of operation even though a high average tariff of 0.74 €/kWh is applied. One reason is large electricity losses. On average, the customers consume only 55% of the electricity output of the diesel generator. According to the data, generator losses amount to 30%, which means that only 70% of the chemical energy stored in the fuel is actually transformed into electric energy. It is assumed that the boat motor is able to transform the chemical energy of one liter of diesel into 3 kWh of electric energy (generator losses ignored). Because of the fact that a diesel generator is able to provide flexible electricity output while controlling the rotation speed, most of the unused electricity must be lost in the grid. This is due to the bad condition of the distribution grid. Another possible factor might be that the operation of the motor and its rotation speed are not adapted to the actual load. The consequence is that nearly half of the generated electricity gets lost, and the fuel is used inefficiently.

4.2 No-subsidy scenario DMG

In order to determine the required tariff for an investment in the DMG in town D without subsidies, the NPV is set to zero and the same inputs are used as for the subsidy scenario. A linear progression of the NPV can be observed. With every €-ct that the tariff rises, the NPV rises by €37,121. The break-even point where the NPV is zero reveals the required average tariff rate of 0.89 €/kWh. The result clearly exceeds the ATP of 0.74 €/kWh. Therefore the required tariff for an economically feasible investment is not applicable in this region. The result clearly exceeds the assumed ATP and therefore every kilowatt-hour sold needs subsidies of 0.15 €/kWh. For this reason, the calculated tariff reveals that the municipal utility in town D subsidizes approximately 17% of the cost of each kilowatt sold.

4.3 LCOE analysis for the DMG

The LCOE for the DMG in town D of 0.89 €/kWh consists of 76% fuel costs, 13% staff costs during the operation, 7% hard costs for the diesel generator, 2% project development costs, and 1% distribution costs. CAPEX are found to account for 11%, OPEX for 89% [6] (p.18). The 0.89 €/kWh represent the required tariff calculated in the no-subsidy scenario. The number of customers is based on TTA data (based on an average number of connections of 700 in 2018). 89% (0.79€/kWh) of the LCOE are necessary to cover the OPEX. Because the major cost driver are fuel costs, the system's profitability is heavily influenced by the fuel price, which represents a high risk for investors because the fuel prices are difficult to predict. Additionally, the high amount of carbon dioxide emitted by the generators might be problematic for DMG investments in the future if carbon prices are being introduced. In light of stiffened climate policy and the changing environmental awareness, the fuel price is more likely to rise than to decline.

4.4 Subsidy scenario SMG

The NPV for the base case amounts to a negative value of €-1,374,109. This means that an implementation of this project today if fully financed by soft loans, and under the same conditions as in reality (based on TTA data) would produce losses of more than €1.3 million. Therefore, for the installation and planned operation over 30 years, subsidies in the same amount are required for its profitable realization. This amount of money corresponds to 39% of the total expenditures that need to be subsidized.

4.5 No-subsidy scenario SMG

For an economically feasible investment with an NPV equal to or greater than zero, the SMG in town S needs to charge 0.86 €/kWh for being independent of subsidies. Therefore, the SMG system under the current conditions is economically not viable because the calculated required tariff clearly exceeds the ATP of 0.74 €/kWh. If the required tariff is applied, the population of town S would not be able to pay the offered electricity by the SMG with the consequence of a decline in demand. The calculation assumes that the capital is fully financed by soft loans, which are not considered subsidies in this context. Figure 7 displays the NPV progression depending on the charged tariff. As in the previous DMG case, a linear progression is observable. With every €-ct that the tariff rises, the NPV rises by €33,869.

4.6 LCOE analysis for the SMG

The LCOE for the SMG in town S amount to 0.86 €/kWh. As it is common for investments in renewable energies, the OPEX stays low and the CAPEX strongly dominates the expenditures, in this case with a share of 82%. It is surprising that the project development category takes the biggest LCOE share (28%) instead of the costs for battery storage (13%) or solar generation (18%). Another surprising fact is the high cost for power distribution. Even though town S is small, the distribution costs come up to 13%, which is the same level as the cost for the battery storage. Including the cost structure taken from the existing literature, the distribution costs of a well-run hybrid mini-grid correspond to less than a quarter of the battery storage costs [6] (p.18). Due to the big difference between the case and the literature regarding distribution and battery costs, this investigation estimates significant potential costs savings for the distribution category. Within the framework of a scientific paper, the type of costs included in each category are assumed to be the same. Nevertheless, it is important to note that the analyzed categories of the case and the literature might include different types of costs and therefore need not be identical. Finally, the greatest saving potentials show the two CAPEX categories “project development” and “distribution”. Hardware costs – i.e. components of conversion, battery, and solar power generation systems – are expected to decline further in the near future.

4.7 Demand stimulation scenario for the SMG.

The study shows that the actual consumption of the electrical energy produced remains on a low average utilization level of 49% due to a volatile and fixed PV power output, distribution losses, and a small amount of productive usage. For utilization rates between 49% (i.e. the current UR of the SMG in town S) and 90%, Table 2 displays the large impact on the LCOE for the SMG case study. The underlying calculation of Table 2 assumes that the UR remains constant over the 30 years lifetime. Additionally, it is assumed that the LCOE is equal to the required tariff for an *NPV* = 0 and that the tariff remains constant during the entire operation.

Table 2. LCOE results

Average UR [%]	Av. Annual Cons. [kWh]	LCOE [€/kWh]
49*	212,816	0.86
60	260,591	0.70
70	304,023	0.60
80	347,454	0.52
90	390,886	0.47

* Current situation

Furthermore, the result of the calculation with the more realistic UR assumption (Fig. 5) is an LCOE of 0.62 €/kWh. The estimated demand stimulation offers the possibility to reduce the actual LCOE of 0.86 €/kWh to about 0.24 €/kWh, which corresponds to cost savings of 28%. When assuming the actual tariff of 0.48 €/kWh as constant; the NPV rises from €-1,374,109 (for a constant demand of 49% of supply) to €-711,219. Therefore, around €662,890 of capital can be saved by demand stimulation. Once again, the calculation does not differentiate between past and future values. It assumes a total new implementation of the SMG and calculates the economic viability based on the values extracted from the real-world case in town S. However, note that costs for demand stimulation are ignored for simplicity reasons. These costs might appear in the form of expenses for providing electrical appliances or costs of other customer management measures aimed at stimulating demand. Future investigations could be insightful if demand stimulation costs are determined and included in the profitability analysis.

4.8 Hardware cost decline scenario

Oriented at prior literature, the study applies a 3% hardware cost decline per year for this scenario (see section 3.1.7). The results are reported in Table 3. The reported LCOE values reflect the tariffs required for reaching the break-even point. According to the results obtained, an LCOE decline of 0.08 €/kWh until 2021 can be observed, corresponding to cost savings of 9% regarding the original LCOE of 0.86 €/kWh.

Table 3. Hardware cost decline (generation, conversion, and storage)

[%]	Approximate time [a]	LCOE [€/kWh]
0	2014 (case data)	0.86
3	2015	0.85
6	2016	0.83
9	2017	0.82
12	2018	0.81
15	2019	0.80
18	2020	0.79
21	2021	0.78

4.9 Scenario combination (hard cost decline, demand stimulation)

The objective of this combined scenario is to reveal the lowest LCOE possible for a well-managed SMG implemented in 2020. Based on the hard cost decline discussed earlier, this scenario assumes an 18% decrease of the given investment costs from 2014 until 2020 regarding the three categories “generation”, “storage”, and “conversion costs”. Simultaneously, the simulation assumes the UR curve presented in Fig. 5, with utilization rates starting from 50% and rising up to 85%. Again, the analysis ignores demand stimulation costs.

Combining both cost reduction potentials, the LCOE (required tariff for breaking even) amounts to 0.57 €/kWh for the SMG. If the actual tariff is assumed to be constant with a value of 0.48 €/kWh, the NPV amounts to €-485,311 (i.e. subsidies to that amount are required for reaching the profitability threshold). The achievable LCOE differs by 0.09 €/kWh from the actual average tariff. A rise in tariff by this amount is likely to be acceptable given the fact that customers in town D are able to pay a tariff of 0.74 €/kWh on average. Therefore, solar-PV-based mini-grids appear to be economically sustainable in this region. A more detailed investigation of the ATP should be made in future research.

Demand stimulation and hard cost decline in the near future are two aspects with great impact on the profitability of solar PV mini-grids. Further cost reduction potentials for mini-grid systems exist, such as the reduction of financing costs, regulatory costs, and OPEX, but which are not further investigated here due to space constraints. More research is needed in order to reduce the gap between theoretical modeling and real data. With more research in this area, the lack of information and confidence of investors can be reduced. As a consequence, more solar PV mini-grids can be built, such that the global community gets one step closer to the United Nations Sustainable Development Goal #7 of universal energy access in 2030.

Because of the fact that a diesel generator is able to control the electricity output with its rotation speed, a demand stimulation scenario for the DMG is not included. Furthermore, diesel generators are optimized over many years, and it is assumed that a hard cost decline with a big impact on system profitability is unlikely to happen in the near future. Therefore, the hard cost decline scenario is not applied for the DMG either.

5. COMPARISON OF RESULTS

The characteristics of the SMG in town S and the DMG in town D are compared next, and some light is shed on the relative merits and disadvantages of each system.

First, the LCOE for both systems are compared with each other (Fig. 6). Surprisingly, the LCOE of the SMG is slightly lower than that of the DMG and thus the SMG is found to be the more profitable investment. The yellow bar represents the possible cost reductions due to demand stimulation and hardware cost decline (see Subsection 4.9). This result contradicts findings from earlier research where the LCOE of DMGs (0.27–0.39 €/kWh; [7] (p.70) tends to be lower than the LCOE of well-run SMGs (0.55 €/kWh; [6] (p.17). Likely, the poor distribution system and inefficient electricity generation of the DMG is responsible for the unusually high costs. On the other hand, the result for the LCOE of the SMG matches with findings from the literature, and the mentioned cost reduction would lead to similar LCOE levels as estimated in [6].

Second, the sensitivity of the NPV with regard to tariffs charged is depicted for both types of mini-grids, together with the profitability thresholds (where *NPV*=0) and break-even between DMG and SMG. Fig. 7 shows that the NPV of the SMG (green line) rises more slowly than the brown line of the DMG, implying that the DMG benefits more from a unitary tariff increase of 1 €-ct than the SMG. It can be concluded that the intersection marks a turning point for the investment decision in favor of one or the other type of mini-grid. Specifically, an investment in the DMG in town D is more profitable for tariffs >1.25 €/kWh, whereas SMG investments in town S are favored for tariffs < 1.25 €/kWh. However, low tariffs above 1 €/kWh are not realistic as the ATP in rural areas of developing countries is far below.

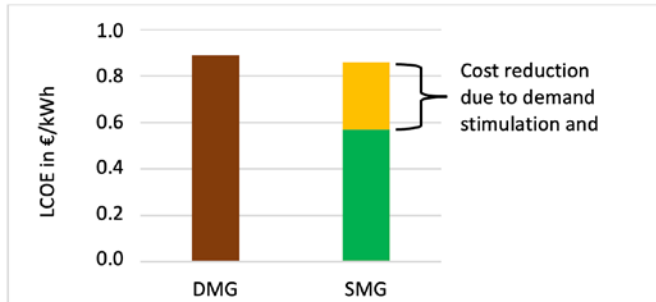

Fig. 6. LCOE comparison [€/kWh], DMG vs. SMG

6. CONCLUSION

This study presents a comparative profitability analysis of a solar-PV-based mini-grid (SMG) and a diesel-mini-grid (DMG) in West Africa. It presents an innovative discounted cash flow valuation approach tailored for the assessment of mini-grid investments. The investigation combines local site data with proven economic methods in order to reduce the gap between theory and real-world implementation. It sheds light on the question of whether mini-grids for rural electrification in developing countries need to be subsidized or not. The calculations are based on real-world site data from 2018 of two towns located in West Africa, provided by TramaTechno Ambiental (TTA), a developer of projects based on renewable energies. The LCOEs for the installed systems were determined for scenarios with and without subsidization. The research also estimates the profitability of the SMG for the case of an installation in early 2020, considering both a hardware cost decline and demand stimulation scenario.

Several assumptions were made for the application of the DCFM. The profitability of project investments was investigated for full funding by international development organizations. Risk-adjusted interest rates of 5% (DMG) and 4% (SMG) were applied to the NPV model. The number of customers was assumed to be constant during the project's lifetime (DMG: 700, SMG: 560). The results are related to a 20-year (30-year) lifetime for the DMG (SMG). The model considers a degradation of the PV output of 0.7% p.a. [10] (p.7). Additionally, OPEX, CAPEX, and revenue data from TTA were used to generate realistic cashflows. While the SMG in town S operates privately with financial support from the European Union, a public institution operates and subsidizes the DMG in town D.

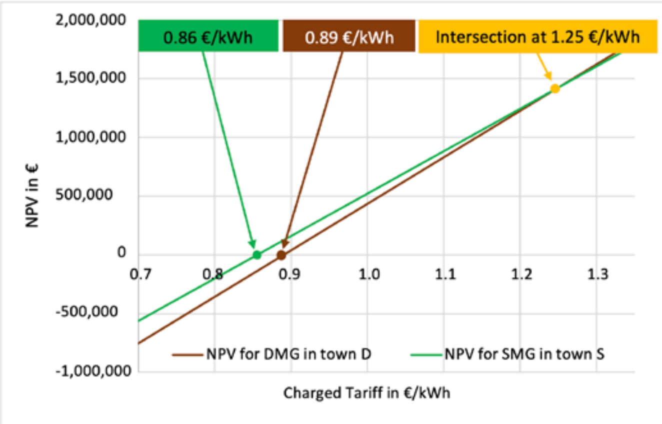

Fig. 7. NPV sensitivity to tariffs charged, DMG vs. SMG

As expected, the SMG in town S is not economically viable under current conditions. When charging the actual tariff of 0.48 €/kWh, a subsidy of more than €1.3 million is required. In order to run the SMG profitably without any subsidy, a minimum tariff of 0.86 €/kWh is necessary (the SMG is operated 24 h and 7 days a week, the DMG only during nighttime).

Surprisingly, a higher tariff of min. 0.89 €/kWh needs to be charged for a profitable DMG in town D using actual specifications and assuming a no-subsidy scenario.

The results obtained in the present study contrast with common findings in recent literature. Other researchers have claimed that the LCOEs for SMG (0.6–1 US$/kWh) are usually higher than for DMG (0.35-0.7 US$/kWh; [6] (p.17). The present study concludes that the high distribution and generation losses of the DMG in town D can lead to an unusually high LCOE. It reveals further that the DMG requires subsidies because of inefficiently used resources, but that with the right investments economic feasibility could be reached.

Furthermore, the research analyzes the share of each cost category per kilowatt-hour for each of the two mini-grid types analyzed. The objective of the per-unit economic analysis is to show the cost-saving potential in a transparent way. The cost of producing one kWh from the SMG is mainly determined by the CAPEX (82%). High hardware and development costs make a high upfront investment necessary. In contrast, the DMG cost per kWh is strongly determined by the OPEX (89%). Some 76% of the price per kWh is required to cover the fuel costs. Since the installation of the SMG in 2014, generation, storage, and conversion costs declined markedly. The per-unit economic analysis laid the foundation for a profitability analysis that also includes the simulation of a hardware cost decline for the SMG. The model used assumes a hardware cost decline of 3% p.a. (corresponding to a cost decline of 18% since 2014). The estimation reveals an LCOE decline of 0.07 €/kWh, with a final value of 0.76 €/kWh for an installation in 2020. Still, assuming an Ability to Pay (ATP) of 0.74 €/kWh in developing countries, a system with such figures is unlikely to become profitable.

The research reveals that the actual utilization rates of both mini-grid studied (SMG, DMG) are significantly lower than the achievable levels. The average UR of the SMG amounts to only 49% in its fourth year of operation (2018). Based on existing literature, a realistic demand increase was simulated with a rising UR curve during the project's lifetime. The result reveals demand stimulation as the most important cost reduction factor, even more relevant than the hardware cost decline. The LCOE of the SMG declines to 0.62 €/kWh in the demand stimulation scenario. Combining both cost reduction potentials (hardware cost decline and demand stimulation), the calculation yields the lowest LCOE of 0.57 €/kWh for a non-subsidized SMG installed in town S in early 2020. This LCOE declines way below the actual charged tariff in town D (0.74 €/kWh). Therefore, it can be concluded that modern SMGs are likely to be economically feasible in developing countries under the stated conditions. A hardware cost decline for a DMG is in comparison with the SMG unlikely to happen and has therefore not been simulated.

The following results are surprising and contrary to our a-priori expectations: The net cash flows for an investment in a DMG like in town D are negative during all years of operation (assuming the actual tariff of 0.74 €/kWh). It is concluded that high distribution and generation losses are leading to non-profitable operation of this DMG. Furthermore, it is unusual for a SMG that the project development costs represent the largest cost share. With a view on benchmark values, it is estimated that costs for this category can be reduced significantly in order to lower the LCOE of the SMG. As a consequence, SMG are likely to be economically viable in the future even if higher interest rates are applied.

The approach adopted of including the demand stimulation in the DCFM has been proven as useful and effective for calculating the actual LCOE of a well-managed SMG. Guided by an analysis of the Rocky Mountain Institute [6], especially the elaboration of the unitary costs per kilowatt-hour was found to be valuable for answering the research question. This is due to the fact that the analysis increases the transparency regarding the cost shares and enables further cost-saving simulations.

Contrary to the findings of a majority of existing studies, it is shown that well-managed mini-grids are already economically feasible in areas with a high ability to pay (> 0.57 €/kWh). However, the usual ability to pay is lower and it is confirmed that the findings of earlier studies acknowledging that profitable operation of SMG without a need for subsidization will only come true at rising household income levels [11] (p.86). Additionally, the LCOE projected in an earlier study by Agenbroad et al. [6] is rejected as a LCOE decline to 0.23 US$/kWh (0.21 €/kWh) by 2020 does not seem to be realistic in light of the results obtained in the present study.

This research could not scrutinize the ability to pay of developing countries with a high potential for rural electrification and thus had to make use of benchmark values. Such a more thorough investigation was beyond the scope of this study. In addition, further research is required in order to carry out impact assessments of cost reductions, especially regarding operating costs, financing costs, and regulatory aspects. Also, future research should examine whether the utilization rates assumed are feasible, and how they can be raised in the future, as the UR was found to be a key factor for the profitable operation of mini-grids.

Finally, in light of the main results, it can be expected that investments in renewable energies for rural electrification will rise significantly in the near future due to declining hardware costs and rising operational efficiency. Nevertheless, in order to achieve the goal of universal electricity access until 2030, in the foreseeable future, substantial subsidization is still required for low-income regions.

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