Energy 66 (2014) 523–534

Contents lists available at ScienceDirect

Energy

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

# Analysis of the cost of reliable electricity: A new method for analyzing grid connected solar, diesel and hybrid distributed electricity systems considering an unreliable electric grid, with examples in Uganda

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A R T I C L E I N F O

*Article history:*
Received 28 May 2013
Received in revised form
3 December 2013
Accepted 6 January 2014
Available online 7 February 2014

*Keywords:*
Grid-connected PV systems
Distributed energy systems
Reliability
Availability

A B S T R A C T

More than 1.3 billion people lack access to grid electricity. Uganda provides a typical example of an under-electrified country, with less than 12% of Ugandans having access. To address the lack of electricity access, there has been much analysis devoted to grid-connected distributed generation. What these analyses lack is a consideration that even where grid electricity reaches people, it is not always reliable; customers often experience hundreds of outage hours per month. This paper addresses this analytical shortfall to provide new methods to analyze reliable electricity and identify optimal systems to provide more reliable electricity. We adapt the HOMER (Hybrid Optimization Model for Electric Renewables) in this work to address unreliable electricity from the grid, and develop a method for determining optimal system configurations and predicting electricity costs for reliable power generation in regions with unreliable grid electricity. We demonstrate the method for a village in Uganda, but the method holds universally. Results indicate that diesel is the most economical choice, but slight increases in diesel and decreases in PV (photovoltaics) prices make solar/diesel hybrid systems competitive. Improved reliability increases cost, but the increase of can be justified for users needing more reliability.



## 1. Introduction

Despite decades of international development spending, almost 80% of people in the developing world still have no access to electricity; this leaves one-quarter of the world's population without access to modern energy services [1–3]. The electricity shortfall is concentrated mostly in Africa and southern Asia, and particularly in rural populations in these regions: 8 out of 10 who lack electricity are in rural areas of the developing world [4]. In Uganda, as with most of sub-Saharan Africa, only 8–12% of people have access to electricity from the grid, and this drops to fewer than 4% outside of urban areas [2,3]. The small fraction that is connected to the grid also suffers from frequent and lengthy outages, with various sources indicating that Uganda experiences between 70 and 125 outage days per year [5,6]. And once again, in rural Uganda, the availability and reliability are even worse than the documented averages [3]. Umeme, the Ugandan distribution utility, does not publish standard outage statistics and data from international sources is sparse, but scheduled and unscheduled outages are common [5,7,8]. Fig. 1 illustrates the frequency and duration of outages in Uganda and 15 other sub-Saharan African countries. On average, Uganda experiences more than 100 h of outages per month from an average of 10.7 outages per month, with a mean outage duration of 10.1 h. As unreliable as the Ugandan grid is, Fig. 1 shows that it is far from the least reliable grid in the region.

It is well understood that lack of access to affordable energy stunts economic growth and human development, and that increased energy consumption correlates with increased GDP (gross domestic product) and in HDI (human development index) scores [9,10]. In addition, a regression of GDP per capita versus the average number of days per year with outages from 91 countries is shown in Fig. 2, where the negative correlation between outage days and incomes is observed. Reducing outage days from 100/yr to 10/yr correlates to an increase in GDP per person from $1900 to more than double that at $5500. Note that no country with an average of less than 1 outage day per year has a GDP per capita of less than $10,000. This indicates that reduced power outages are

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0360-5442/$ – see front matter 
http://dx.doi.org/10.1016/j.energy.2014.01.020

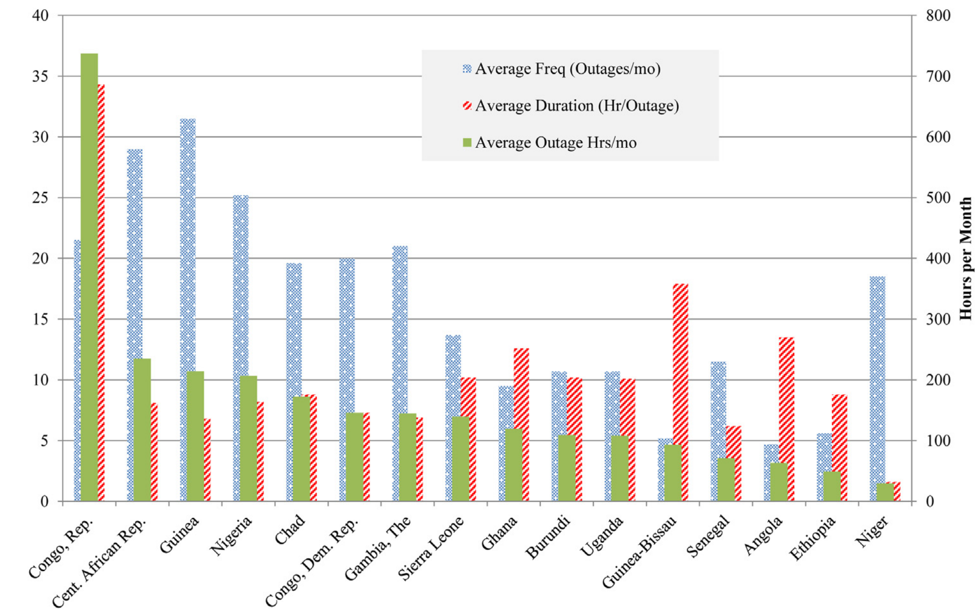



**Fig. 1.** Outage frequency (events/month) and duration (h/outage) (left axis) and total average outage hours per month (right axis), data from World Bank survey data, Uganda and sub-Saharan Africa [28].

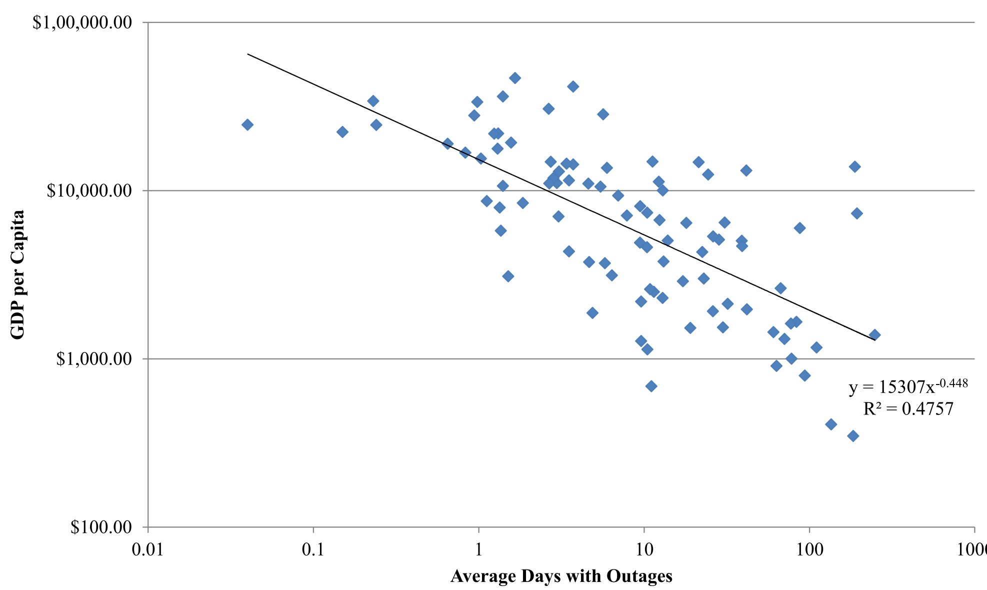



**Fig. 2.** GDP per capita is negatively correlated with the average number of days per year with outages, as shown in the (log–log) plot, data from the World Bank [28].

associated with increased GDP, improved economic growth, and development. If constructive efforts are made to reduce or mitigate grid outages, increased GDP can be achieved in Uganda and the dozens of countries that yearly experience an average of more than ten days with outages.

The grid in Uganda fails to provide reliable electricity where it currently reaches, which does not instill confidence in grid extension as a reliable method of electricity delivery – in other words, extension of the grid alone will at most provide unreliable electricity to more people. Despite investment in generation capacity like the Bujagali Dam, alleviation of generation shortfalls has only been temporary and rolling blackouts are expected to be reinstated within the next 6 months [11,12]. The trend is consistent across Africa where new electrical connections are not keeping up with population growth and even when new capacity is installed; a quarter of installed capacity is idle due to aging plants and poor maintenance [13]. In effect, the lack of access and reliable access means that in Uganda and much of Africa, it is not a choice between grid extension and DER (distributed energy resources), it is a choice between DER and building a new bulk grid from the bottom up. Analyses to date of the trade-off between DER and grid extension fail to address a fundamental issue – that even where electricity services reach people in the developing world, they are often not reliable and so fail to address the challenge illustrated in Fig. 2. The failure to address this fundamental point may be resulting in a bias toward grid extension and grid-connected systems as the solution to Africa's electricity shortfalls, when in effect it can be only part of the solution.

To address the lack of electricity access in Uganda and other parts of the developing world, numerous studies analyze hybrid distributed energy resources (DER) consisting of PV (photovoltaics), wind, biomass, and diesel, with comparison to standalone, grid tied, or grid-only systems. In recent years, extensive research in form of experimental as well as simulation studies has been continued to be carried out on the application of PV systems as DER to harness power from the non-conventional energy sources with low environmental impacts [14]. A hybrid PV/diesel green ship operating in standalone and grid-connected mode was experimentally investigated. The aim of the green ship was partly to support the power grid as a DG source, connected to the smart grid (on land) and as a stand-alone microgrid in the near future [15]. In the literature, grid availability and reliability are consistently absent from the analysis. Levin and Thomas' least-cost network evaluation provides a powerful method for comparing costs and benefits of DER versus grid extension [16]. Their detailed costing of grid generation, transmission and distribution capital costs should incorporate reasonable availability and reliability in the resulting centralized systems. Their analysis and results in the case of Uganda indicate that grid extension is likely the best option in this densely populated country, but in application grid extension has not provided reliable electricity. Some study of actual costs of grid extension and the achieved availability and reliability is warranted to confirm or update the cost functions for application in Uganda and the developing world. Similarly, in Ref. [17] the authors analyze grid extension versus DER in Africa, providing insightful analysis and GIS (Geographic Information System) images that are both beautiful and rich in information. Again, much of Uganda is shown to have high potential for grid extension to be the least cost alternative for electricity. But neither of these studies explicitly addresses the lack of availability and reliability in the existing infrastructure.

Economic analysis in Ref. [18] illustrates the challenges of achieving grid parity with renewables without tax credits, but again this analysis is performed in the United States, with no consideration of the challenge or value associated with providing backup for an unreliable grid.

Other literature shows that DER can provide affordable power for communities and small enterprises, but are preferred to grid extension only where distance from the grid is large [17,19–21]. Fossil fuel availability and pricing – with taxes and subsidies having a notable impact – are critical inputs in determining the economic competitiveness of fuel based DER, just as wind availability, insolation, and biomass sources are for renewable systems. Szabó [17] clearly shows how the affordability of diesel based DER follows the transportation network and the availability of fuel. Of particular note [22], offers longitudinal evidence covering 13 years of diesel-based DG in Kenya, highlighting that the income and productivity impacts of DER can provide cost-recoverable power.

Only Ref. [23] considers the availability of the grid as part of the grid versus standalone comparison in their EDL (economic distance limit) calculations. EDL is the distance at which the economic tradeoff between grid extension and DER becomes equivalent. They compare three grid availability rates (6 h/day, 8 h/day and 12 h/day) and calculate EDL for DER systems at power levels between 10 kW and 100 kW. In their results, EDL is linearly related to availability, such that the EDL where the grid is available 12 h/day is twice the EDL where the grid is available 6 h/day. However, only a fixed outage time per day is considered, with no analysis of actual duration or frequency of outages. In cases where outage durations have a wide variance, this could significantly change the demand for self-generation, the optimal DER system configuration, and perhaps weaken the case for grid extension.

In previous work [24], we presented PV systems as an alternative to diesel in grid-connected distributed generation. Results indicated that although PV was not cost competitive with grid-only solutions today, future dependence on diesel as a backup to hydro-based grid power could increase costs and environmental impacts. This analysis did not include consideration of an unreliable grid, which we now note is an important variable that could even change the near-term results in favor of DER.

## 2. System configuration considering an unreliable grid

Including random variation in the number and duration of outages could impact the calculations for cost effectiveness of grid extension and grid tied DER, with impacts on the tradeoff and optimal system design that are not straightforward. Consider, for example, the production of a good that requires labor and electricity as inputs. A grid extension with predictable or scheduled outage times of 12 h per day allows for planning of production schedules to match power availability. If the same total duration of outages were achieved with a distribution grid with MTBF (mean time between failures) of 12 h and MTTR (mean time to repair) of 12 h, it would be much more costly to adapt a workforce to the randomly varying power availability. Also, designing DER optimized for the frequency, duration, and variation in outage times to achieve the desired minimum availability and reliability would be costly as compared to one that is optimized for a fixed outage schedule. One must conduct the analysis, either in closed form or in simulation, to determine if grid extension, grid-tied DER or stand-alone DER are optimal, or whether any such options are even affordable.

One of the reasons grid availability and reliability and random outages are not taken into account in the analysis is that one of the leading tools for economic analysis of microgrids, HOMER (Hybrid Optimization Model for Electric Renewables), does not include simple methods for incorporating grid availability and reliability. HOMER is a useful tool for analyzing renewable and fuel based DER, especially because it has built in algorithms to simulate thousands of different systems for every hour of the year, over multiple year lifecycles [25]. HOMER then ranks the considered systems by financial performance and technical feasibility. HOMER has been used extensively for stand-alone and off-grid DER analysis [19,20,24,26,27]. But in all of the HOMER-based analyses, if the grid is connected it is available 100% of the time.

In contrast, given the World Bank [28] data shown in Fig. 1, we can calculate the actual availability and components of MTTR and MTBF for the grid in Uganda. Availability is the percentage of time that a system is operational, or the time the system is up ($T_{up}$), divided by the total time at risk ($T_{total} = T_{up} + T_{down}$) [29]. For the average month lasting 730 h, then Uganda's 10.7 outages per month averaging 10.1 h long gives a $T_{down} = (10.7 \times 10.1)$ or 108 h on average for the grid in Uganda. The 108 h of downtime are not accounted for by the modeling and simulation in our previous work.

As shown in the general form in Equation (1) A (availability) can be calculated for any country or region from only the average downtime experienced per month [29,30]:

$$A = \frac{T_{up}}{T_{up} + T_{down}} \tag{1}$$

$$= \frac{\mathrm{MTBF}}{\mathrm{MTBF} + \mathrm{MTTR}} \tag{2}$$

where

$T_{up}$ = average up-time per month (h)
$T_{down}$ = average down-time per month (h)
MTBF = mean time between failure (h)
MTTR = mean time to repair (h)

As MTTR is defined as the mean time to repair a failed component [29], it is simply the average time the grid is down per outage. Knowing MTTR and $A$, we can calculate late MTBF from (2). For the Ugandan example, as noted, MTTR = 10.1 h, MTBF is then calculated as 58.1 h and availability $A$ is 0.85. This signifies that the grid is only available 85% as opposed to 100% which was assumed in our previous research, hence the need to incorporate the study of reliability. In the distribution network expansion, a reliable energy supply with predefined satisfaction level should be provided for customers. Thus, network reliability is one of the major issues to be considered [31].

Although we can calculate $A$, MTTR and MTBF for the grid connection in general, HOMER does not include methods to easily enable simulation of an unreliable grid. HOMER does provide a recommendation for a modeling an unreliable grid using a generator module with scheduled downtime to approximate an unreliable grid, and modifying the parameters of the generator and the fuel to match the cost of grid electricity [32]. As advised in the HOMER user group, we created a generator called "Grid Proxy" with 100% efficiency, created a new fuel for the "Grid Proxy" generator called "Grid Electricity" and defined it to have 1 kWh/kg of fuel, and a price of $0.171/kg. A full description of the HOMER inputs we used is provided in Appendix A.

To approximate random failures, we simulated grid outage times using Excel. Fig. 3 illustrates how the outage times are input into HOMER by selecting "Forced off" for times when we want to simulate a grid outage and "Optimized" for times when the grid is available. The outages were simulated in excel, using an exponential pseudo-random variable generator using MTBF and MTTR calculated from the World Bank data for Uganda. To populate the HOMER generator schedule, the simulator was used to generate 24 up-time and down-time schedules (January weekdays, January weekends, February weekdays, etc.) of 24 h each. The schedule can be represented as a 24 × 12 × 2 matrix of indicators ($\mathbf{I}_{j,k,l}$) where $j$ indicates the hour of the day, $k$ indicates the month and $l$ indicates weekday (1) or weekend (2). First, a seed value was simulated to indicate whether the grid was up or down in the time preceding the simulation. The seed value $\mathbf{I}_{0,0,0}$ was simulated from the availability in Equation (1), given that the probability that the system is on at any given time is the availability [29]. The seed value is then modeled in excel such that:

$$\mathbf{I}_{0,0,0} = \begin{cases} 0 \text{ if } \mathbf{R1} > A \\ 1 \text{ if } \mathbf{R1} \le A \end{cases} \tag{3}$$

where

$\mathbf{R1} = Unif\,(0, 1)$, generated in Excel

Subsequent $\mathbf{I}_{j,k,l}$ were simulated as exponential arrivals of a failure event if $\mathbf{I}_{j\text{-}1,k,l} = 1$ or repair event if $\mathbf{I}_{j\text{-}1,k,l} = 0$. For a possible failure event when $\mathbf{I}_{j\text{-}1,k,l} = 1$, we simulate another random variable **R2** that is uniform on (0, 1), and transform it into an exponential random variable **E1**. This is performed by noting that the failure rate for an exponential random variable, $\lambda_f$, is equal to the inverse of the MTBF, that is $\lambda_f = 1/\text{MTBF}$ [33]. The arrival time of the next failure can be generated as: [34,35]

$$\mathbf{E1} = -\frac{1}{\lambda_f}\ln(1 - \mathbf{R2}) \tag{4}$$

Thus, when $\mathbf{I}_{j\text{-}1,k,l} = 1$ (the grid is on), we can simulate whether a failure occurs in the next hour such that if $\mathbf{E1} > 1$ h, no failure occurred and:

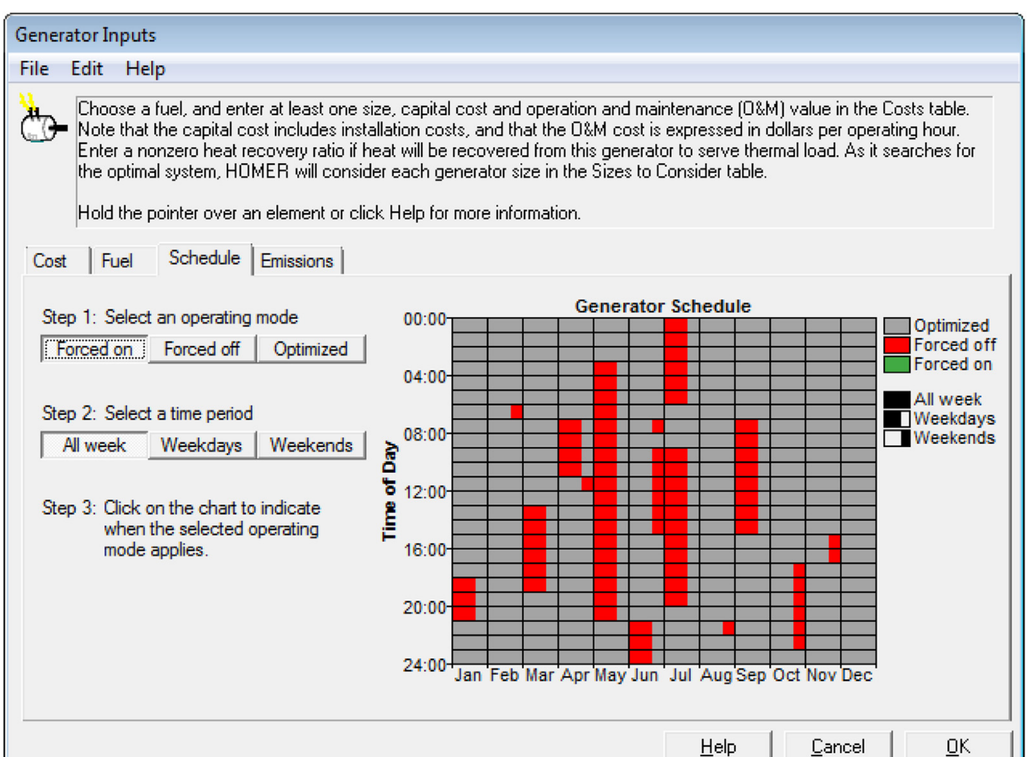



**Fig. 3.** HOMER generator inputs, illustrating a randomly generated grid outage schedule. The grid has failed when "Forced Off", and is available when "Optimized". "Forced On" is not used.

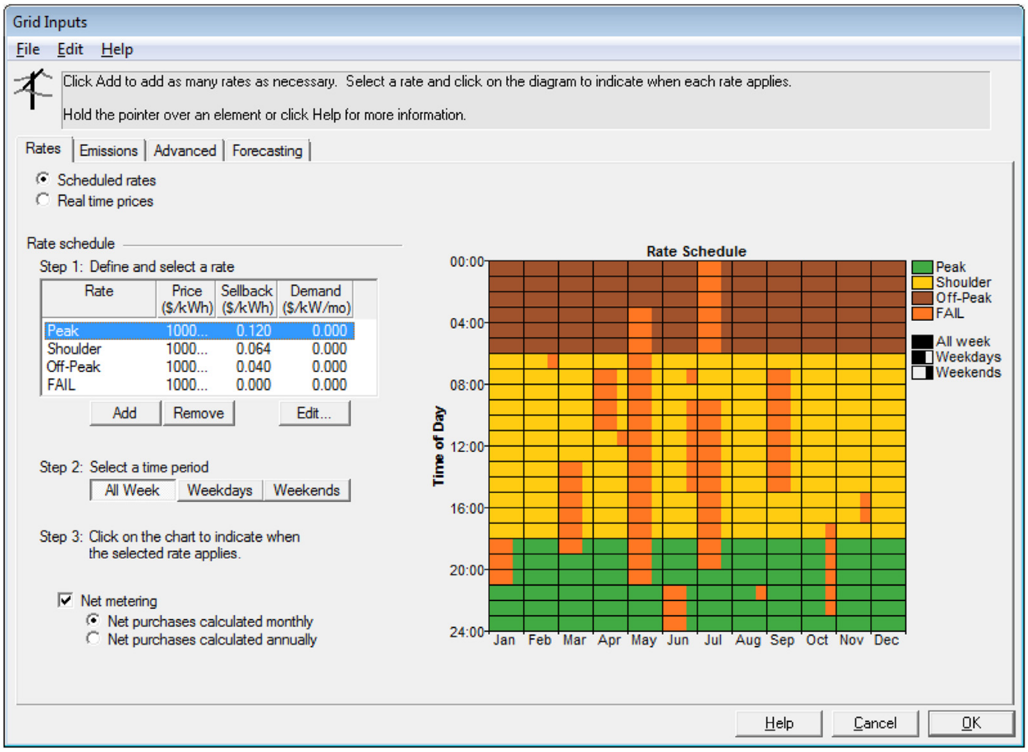



**Fig. 4.** In addition to the peak/shoulder/off-peak rates in tariff rates used in previous work, we add a "FAIL" schedule and rate of \$0/kWh when the Grid Proxy schedule indicates a grid failure. "Off-Peak" in the morning, "Shoulder" during mid-day, and "Peak" rates are effective in the evenings.

**Table 1**
HOMER inputs, modified data on option sizing and other parameters for considering an unreliable electric grid.

| Options | Options on size and unit numbers (expanded search space) | Additional information |
|---|---|---|
| Diesel generator (Cmty Backup Gen) | 0–70 kW | Capital = \$250/kW<br>Replacement cost = \$200/kW<br>Diesel price = \$1.3/L<br>(Ugandan Shilling 3400/L) |
| Solar PV | 0–150 kW | Capital = \$6000/kW<br>De-rating factor = 90% |
| Converter | 0–150 kW | Converter efficiency = 90% |
| Battery | 0–512 strings<br>(1024 total batteries) | Surrette 6CS25P battery type<br>Nominal voltage = 6 V<br>Nominal capacity = 1156 Ah<br>Usable capacity = 8523 kWh |

$$\mathbf{I}_{j,k,l} = \begin{cases} 0 \text{ if } \mathbf{E1} > 1 \\ 1 \text{ if } \mathbf{E1} \leq A \end{cases} \tag{5}$$

We can continue for each $\boldsymbol{I}_{j,k,l}$ by using the memory-less property of the exponential random variable [35]. The matrix $\boldsymbol{I}_{j,k,l}$ of the randomly generated on/off indicators is shown in Fig. 3. The availability realized in simulation, $\hat{A}$, can be calculated using Equation (1) and the simulation results. Our model in Excel gave 7310 h of up time and 1450 h of downtime to get a simulated availability, $\hat{A} = 0.834$, consistent with the survey data from Uganda with $A = 0.85$.

Using the generator proxy method to simulate an unreliable grid in HOMER is a great improvement on ignoring electrical power failures, but the scheduling method still has shortcomings. The input schedule holds for an entire month, such that same outage schedule is experienced every weekday in January. While a different schedule can be used on weekdays versus weekends each month, and these can vary by month, the lack of a more random outage generator that parallels real-world scenarios does mean the outages are not completely randomized. Even so, this is a great improvement on ignoring stochastic variations in grid availability as has been done in all previous studies.

Using the generator schedule method described above as a proxy for an unreliable grid, we re-examined the grid-connected PV system presented in our earlier work [24], to determine how grid outage duration and frequency impact the resulting optimal configurations, components and the LCOE (Levelized Cost of Electricity) at various thresholds for allowable capacity shortage. In large part, the inputs will be the same, replicating the load profile, solar resource, basic grid architecture and economics. Each of the changes required for this analysis is outlined below.

### 2.1. Grid availability

As noted, the simulated grid will no longer be available all of the time. This will be modeled via the proxy generator scheduling method described above using randomly generated outage schedules with failure and recovery rates from the World Bank data (MTBF = 58.1 h; MTTR = 10.1 h). This will also require a modification of the grid feed-in tariff schedule to prevent the sale of electricity back to a grid that is not available. We do this by altering the HOMER grid inputs for grid feed in tariff to be \$0 when the "Grid Proxy" is scheduled to fail, as shown in Fig. 4. The rate schedule shown in Fig. 4 replicates the previous work [24], adding only the "FAIL" rate, noted in orange (in web version), for times when the grid is not available.

### 2.2. Electricity sources

Some additional generating capacity is needed to address the demand that would otherwise be unmet now when the grid is down. The solar and battery arrays considered in previous analyses were sufficient to offset some grid consumption, but not to provide power to the village when the grid failed. The modified architecture to address additional generation is summarized in Table 1, with full details in Appendix A:

### 2.3. Allowable capacity shortage

Five levels of maximum allowable capacity shortage ratios will be compared in 5 scenarios: 0.20, 0.15, 0.10, 0.50 and 0.00. The existing unreliable grid will meet the 0.20 threshold, while storage or additional generation will be required to meet the more stringent availability requirements, with an expected increase in LCOE. Allowing a capacity shortage greater than zero enables the HOMER optimizer to shed short duration, high peak loads in order to deliver a less expensive system. For example, a 0.05 capacity shortage ratio means that a system that meets 95% of the annual electric load plus the operating reserve is acceptable [25].

## 3. Results and discussions

The purpose of a DER system is to provide reliable electricity in an affordable and sustainable manner. In this analysis we consider sustainability as a secondary concern, and treat the current lack of electricity as a much greater economic and development crisis than greenhouse gas emissions and other pollutants. Renewable DER may help to address the lack of availability and reliability of the bulk grid, but they may not provide a cost-effective solution, and ultimately fossil fuel based DER may be necessary to achieve availability and reliability goals.

### 3.1. Baseline comparison

First, we describe the impact of an unreliable grid on the results from our previous work. We recreate the system from previous work based on the information in Ref. [24], and use this as the baseline for comparison to new results with an unreliable grid. For comparison, the key outputs from the re-created results of three systems discussed in previous work are shown in Table 2 (Options 1T, 2T, 3T) and results from three parallel systems modeled against an unreliable grid (Options 1M, 2M, 3M).

The optimal system from the previous analysis was the grid, with no backup, offering power at \$0.171/kWh. The grid-only solution from our previous work is still available with an unreliable grid, but is only optimal if 17.7% or more unmet load is allowed. With the electricity availability conditions described in Fig. 3, 17.7% (39,900 kWh/yr) of the load will not be served as no DER is available while the grid is down. In earlier work, we also discussed two other options as comparatives: a system including 100 kW PV without battery storage (Option 2), and a system including 100 kW PV and battery storage (Option 3). Columns B, C and D in Table 2 identify the selected system components. These are not optimized system configurations, and are only shown for comparison with previous work. Columns E, G and H highlight the key difference with earlier results, as the previous analysis assumed 100% of the demand can be met by the grid. This paper shows the actual load served (Column E), unmet load ratio (Column G) and the unmet load (Column H). These variables and equations are interrelated, and are all presented for clarity and completeness:

$$E_d = E_s + E_u \tag{6a}$$

$$E_s = E_d(1 - r_u) \tag{6b}$$

$$r_u = \frac{E_u}{E_d} \tag{6c}$$

where

$E_d$ = the desired total energy load
$E_u$ = the unmet energy load
$E_s$ = the actual energy load served, and
$r_u$ = the unmet load ratio

As we continue to discuss improved availability as goal for DER, we note that the unmet load ratio $r_u$ would be equal to one minus the availability $(1 - A)$ if the average instantaneous power load was consistent across the served and unserved loads, such that if:

$$\overline{P}_d = \frac{E_d}{T_{total}} = \overline{P}_s = \frac{E_s}{T_{up}} = \overline{P}_u = \frac{E_u}{T_{down}} \tag{7}$$

where

$\overline{P}_d$ = the average power demand
$\overline{P}_u$ = the average unmet power
$\overline{P}_s$ = the average load served

Then by Equations (1), (6c) and (7)

$$r_u = \frac{\overline{P}_u T_{down}}{\overline{P}_d (T_{up} + T_{down})} = \frac{T_{down}}{(T_{up} + T_{down})} = (1 - A) \tag{8}$$

Even if the average power equivalencies in (8) do not hold, if the failure and recovery events are truly random and of sufficient number, then by the Central Limit Theorem [35], we can take Equations (7) and (8) as approximate equalities such that and take $r_u \sim (1 - A)$. In the case of the simulation example this holds, as $r_u = 0.171 \sim 0.166 = (1 - 0.834) = (1 - \widehat{A})$.

Increasing availability comes at a cost, and so we must also ensure the economic analysis is unaffected by the modeling technique using a generator as a grid proxy. For the economic analysis, note that Column F, Grid Sales, does not depict the data presented automatically in the HOMER results. According to the HOMER

**Table 2**
Simulation results from previous work, now considering an unreliable electric grid.

| A | B | C | D | E | F | G | H | I |
|---|---|---|---|---|---|---|---|---|
| Option | PV (kW) | Batt (#) | Inv (kW) | Load served (kWh/yr) | Grid sales (kWh/yr) | Achieved unmet load fraction | Achieved unmet load (kWh/yr) | LCOE (\$/kWh) |
| 1T | | | | 225,570 | – | – | – | 0.171 |
| 2T | 100 | | 100 | 225,570 | 55,570 | – | – | 0.238 |
| 3T | 100 | 8 | 80 | 225,570 | 53,463 | – | – | 0.244 |
| 1M | | | | 185,670 | – | 0.177 | 39,900 | 0.171 |
| 2M | 100 | | 100 | 200,985 | 53,629 | 0.109 | 24,585 | 0.243 |
| 3M | 100 | 8 | 80 | 204,157 | 52,734 | 0.095 | 21,413 | 0.245 |

model using the grid-proxy generator, some electricity is sold back to the grid even when the grid has failed. However, this is a practical impossibility. An islanded microgrid could sell power to some users, in which case the load and storage in the island must absorb the power from the PV during the grid outages. This power will instead either be sent to storage, if available, or to ground. As such, the amount shown in Column F is the HOMER-recorded quantity of grid sales minus the quantity sold back to the grid during grid failures. Option 3M, for example, in simulation indicated that 67,911 kWh were sold back to the grid in total, but 15,177 kWh of sell-back occurred during grid failures, as shown in Fig. 5. The actual grid sales should then be 67,911 kWh − 15,177 kWh = 52,734 kWh. The sell-back price during outages was set to zero, so that it would not impact the HOMER internal LCOE calculations.

What is most interesting in the differences between the results from the earlier work and the new results is the additional availability provided by the PV generation and battery storage. In the earlier work, it would be difficult to justify the higher LCOEs for Options 2T and 3T without some additional constraint or objective. Options 2M and 3M illustrate that the benefit could be local electricity availability. The question becomes: is it worth a higher price (in these cases an additional \$0.07/kWh) to cut the unmet load ratio from 0.177 to 0.095, effectively increasing the availability from 82.3% to 90.5%? We will explore the cost of availability in more detail in the next section, with system configurations optimized to meet availability constraints.

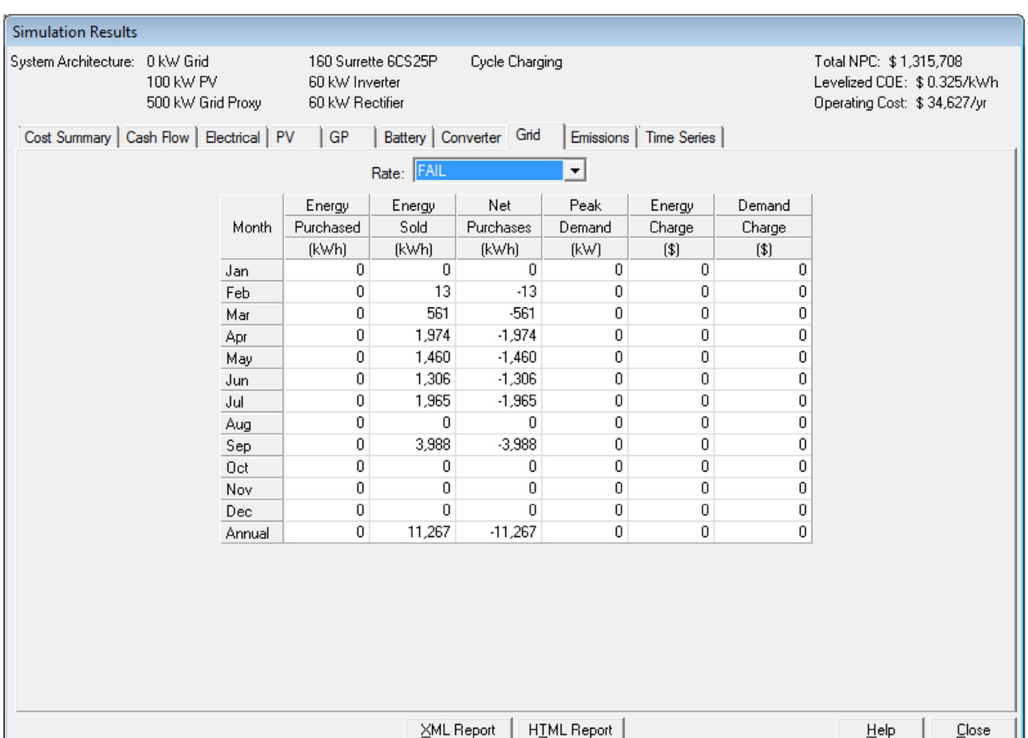
### 3.2. *Optimal systems and performance at various levels of required availability*

In earlier work, it was impossible to economically justify grid connected solar Option 2T or 3T in Table 2. We now study whether the DER options can provide value toward meeting availability constraints. By executing 5 scenarios in HOMER with the same input data and changing only the Allowed Capacity Shortage, we find the optimal systems to achieve capacity shortages of no more than 0.20, 0.15, 0.10, 0.5 and 0 despite dependence on an unreliable grid. While no cost of emissions or fuel tax is included in the simulation, we add a constraint in the analysis to identify solutions without diesel to illustrate the potential additional cost of green solutions. The resulting data, compiled in Table 3, shows the potential benefit of DER in terms of availability and the cost of availability, and the tradeoff between diesel based and renewable options for achieving more electricity availability.

Starting from the lowest availability requirement in Scenario 1 with 0.20 allowable capacity shortage, Option 1M from previous work satisfies the constraint with grid power only serving a load $E_s = 185{,}670$ kWh/yr of the demand $E_d = 225{,}570$ kWh/yr, dropping an un-served load $E_u = 39{,}900$ kWh/yr with an unmet load ratio by Equation (6c) of $r_u = 0.177$.

Options 2M and 3M both provided increased availability with unmet load ratio near 0.1, but neither was optimized against an availability constraint. Options 2, 2b, 3 and 3b offer optimal systems for the availability constraints with unmet load ratios of 0.113, 0.130, 0.084 and 0.0814 and lower LCOEs than the previous work of \$0.193, 0.199, 0.208 and 0.228 respectively. The increased cost of energy is justifiable in terms increased availability and reliability of the system.

The minimum cost systems for the five capacity constraint scenarios are shown in Table 3, both with diesel allowed (Options 2–5) and with diesel forbidden (Options 2b–5b). The unmet capacity shortage ratio constraint is shown in Column B, with resulting achieved unmet capacity and load ratios shown in Columns C and D. System components are shown in Columns E–H, and resulting loads in Columns I–L. Once again, grid sales posted in




| Month | Energy Purchased (kWh) | Energy Sold (kWh) | Net Purchases (kWh) | Peak Demand (kW) | Energy Charge ($) | Demand Charge ($) |
|---|---|---|---|---|---|---|
| Jan | 0 | 0 | 0 | 0 | 0 | 0 |
| Feb | 0 | 13 | -13 | 0 | 0 | 0 |
| Mar | 0 | 561 | -561 | 0 | 0 | 0 |
| Apr | 0 | 1,974 | -1,974 | 0 | 0 | 0 |
| May | 0 | 1,460 | -1,460 | 0 | 0 | 0 |
| Jun | 0 | 1,306 | -1,306 | 0 | 0 | 0 |
| Jul | 0 | 1,965 | -1,965 | 0 | 0 | 0 |
| Aug | 0 | 0 | 0 | 0 | 0 | 0 |
| Sep | 0 | 3,988 | -3,988 | 0 | 0 | 0 |
| Oct | 0 | 0 | 0 | 0 | 0 | 0 |
| Nov | 0 | 0 | 0 | 0 | 0 | 0 |
| Dec | 0 | 0 | 0 | 0 | 0 | 0 |
| Annual | 0 | 11,267 | -11,267 | 0 | 0 | 0 |

**Fig. 5.** HOMER results for grid sales indicated sales during a grid failure. These must be backed out of the results for accurate comparison.

**Table 3**
Simulation results for optimal configurations to meet various reliability and environmental requirements.

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Option | Allowed Cap. shortage ratio | Achieved Cap. shortage ratio | Achieved unmet load ratio | PV (kW) | Batt (#) | Inv (kW) | Gen (kW) | Load served (kWh/yr) | Grid purchases (kWh/yr) | Grid sales (kWh/yr) | Additional load served (versus grid only) (kWh/yr) | Total cost per year Cap + Op ($/yr) | LCOE ($/kWh) | Cost of additional load served ($/kWh) |
| 1M | | 0.1950 | 0.1770 | | | | | 185,670 | 185,670 | 0 | 0 | 31,750 | 0.171 | |
| 2 | 0.15 | 0.1300 | 0.1130 | | | | 10 | 200,125 | 185,670 | 0 | 14,455 | 38,624 | 0.193 | 0.476 |
| 3 | 0.10 | 0.0990 | 0.0840 | | 16 | 10 | 10 | 206,623 | 195,736 | 0 | 20,953 | 42,978 | 0.208 | 0.536 |
| 4 | 0.05 | 0.0471 | 0.0374 | | 16 | 20 | 20 | 217,138 | 195,541 | 0 | 31,468 | 48,639 | 0.224 | 0.537 |
| 5 | 0.00 | 0.0000 | 0.0000 | | 32 | 40 | 40 | 225,570 | 199,667 | 0 | 39,900 | 56,393 | 0.250 | 0.618 |
| 2b | 0.15 | 0.1490 | 0.1300 | 10 | 16 | 20 | | 196,146 | 185,638 | 0 | 10,476 | 39,033 | 0.199 | 0.695 |
| 3b | 0.10 | 0.0940 | 0.0814 | | 64 | 30 | | 207,214 | 218,968 | 0 | 21,544 | 47,245 | 0.228 | 0.719 |
| 4b | 0.05 | 0.0495 | 0.0424 | 20 | 96 | 50 | | 216,001 | 200,150 | 5 | 30,331 | 57,888 | 0.268 | 0.862 |
| 5b | 0.00 | 0.0005 | 0.0005 | 100 | 160 | 60 | | 225,464 | 159,991 | 44,718 | 39,794 | 73,276 | 0.325 | 1.044 |

Column K are modified from the HOMER results, subtracting out the sales that occurred during grid outages. Economic results are in Columns M–O.

Note that the unmet load achieved (Column C) may be different, and usually less, than the capacity shortage allowed. The capacity constraint in HOMER sets a maximum allowed power shortage ratio (Column B). The achieved capacity shortage (Column C) must be less than this, as per the optimization constraint in HOMER. The unmet load ratio (Column D) is the ratio of energy demand left unmet during the allowed capacity shortages and is also $1 - A$. For example, Option 2 in Table 3 sets a maximum of 0.15 allowed capacity shortage ratio. However, after the simulation, HOMER finds an optimum that meets this constraint with an achieved capacity shortage of 0.130 which results in an unmet load ratio of 0.113. The image shown in Fig. 6 illustrates this with a time series from January 5th from the simulation. The demand (AC Primary Load) is shown in blue (in web version). The available grid power, in black, shows an outage between 1800 h and 2100 h. The diesel backup serves this load, but is only capable of delivering 10 kW, hence the unmet load of up to 40 kW shown in red (in web version).

A comparison of the various LCOEs (Column N) versus achieved unmet load (Column D) is shown in Fig. 7. The minimum LCOE increases with increased availability. At the very least, we would expect increased cost for increased load served. The increased cost per kWh shows that increased availability costs more per unit, not just by consumption of more units of electricity. The solar and solar battery solutions from previous work (Options 2M and 3M) are shown for comparison, and are clearly above the minimum price for the achieved availability. The optima for renewable solutions are lower cost than the systems shown from previous work, but more expensive than the options with diesel allowed at every availability level. The increased LCOE for each renewable solution case is almost double the minimum cost LCOE in the same scenario. A linear regression of the LCOE versus achieved unmet load ratio shows the almost two-times cost increase per kWh, as LCOE increases by \$0.0044 for each percentage decrease in unmet load ratio for the minimum cost options and by \$0.0085 for the renewable-only options.

Another view of cost for availability is in terms of the cost/kWh of the additional load served. The LCOE provides the cost for all electricity, or the weighted average of grid and backup power. The cost of additional load served is the average cost of each additional kilowatt hour as compared to another option, which we will note as $C_a^{i,j}$ as the cost per additional kWh served in Option $j$ versus Option $i$ and is given by:

$$C_a^{j,i} = \frac{C_t^j - C_t^i}{L_s^j - L_s^i} \tag{9}$$

where

$i$ = baseline option
$j$ = comparative option
$C_t^i$ = total cost per year for Option $i$ (as shown in Column M), and
$L_s^i$ = load served for Option $i$ (as shown in Column I)

Which for Option 2 as compared to Option 1M is calculated as:

$$C_a^{2,1M} = \frac{C_t^2 - C_t^{1M}}{L_s^2 - L_s^1} = \frac{38,624 - 31,750}{200,125 - 185,670} = \frac{6,874}{14,445} = 0.476$$

The resulting calculations of $C_a^{j,1M}$, the cost for the additional load served as compared to Option 1M, for each of the other options are presented in Column O of Table 3, and displayed in Fig. 8.

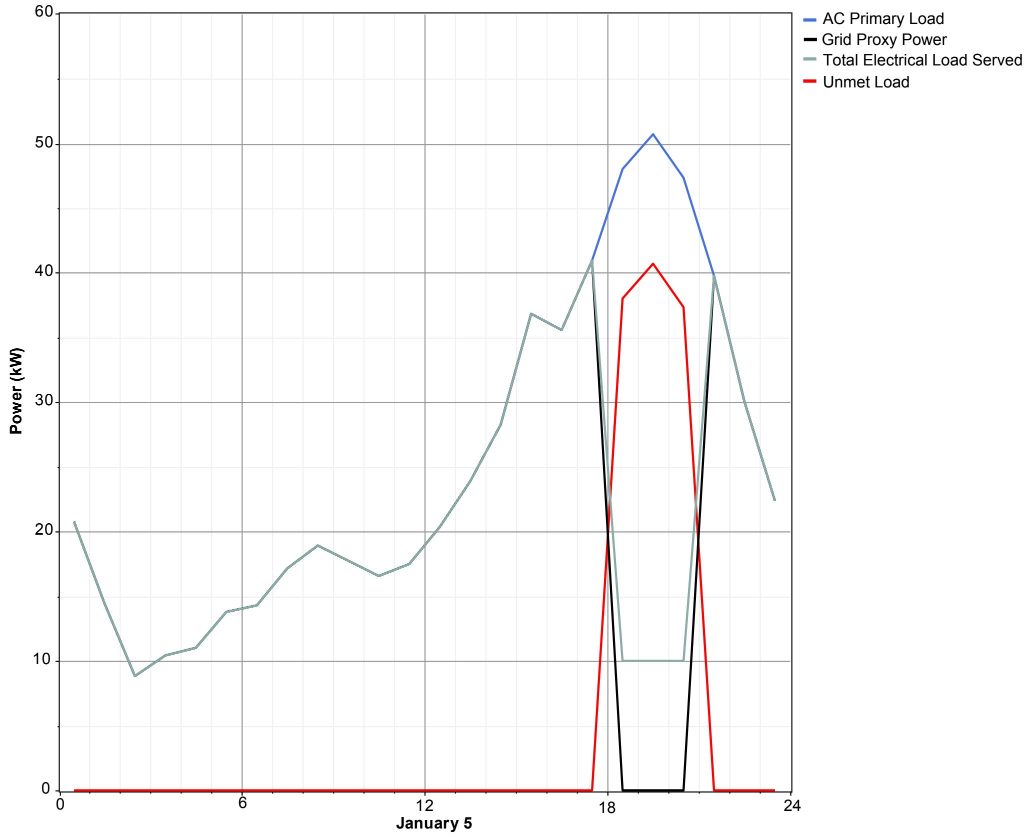



**Fig. 6.** An excerpt of the power profile from HOMER simulation of Scenario 2, Option 2 for a day in January.

Once again, decreasing unmet load ratio (increasing availability) comes at an increasing cost. From Table 3 and Figs. 7 and 8, we see that by reducing the allowable capacity shortage to 0.15 in Scenario 2, the achieved unmet load ratio is reduced from 0.177 to 0.113. The LCOE increases from $0.171 to $0.193. The cost of additional load served is $0.476/kWh, which applies to the additional load served of 14,445 kWh/yr in Option 2.

The increasing LCOE and cost per unit of additional load served is a function of the additional hardware required to meet the increased availability requirements. Option 3 adds batteries to the solution from Option 2, to decrease the unmet capacity and unmet load ratios. To achieve a maximum capacity shortage ratio of 0.05 (Scenario 4), the minimum cost solution requires a larger diesel generator and more diesel generation, as shown in Option 4 Table 3.

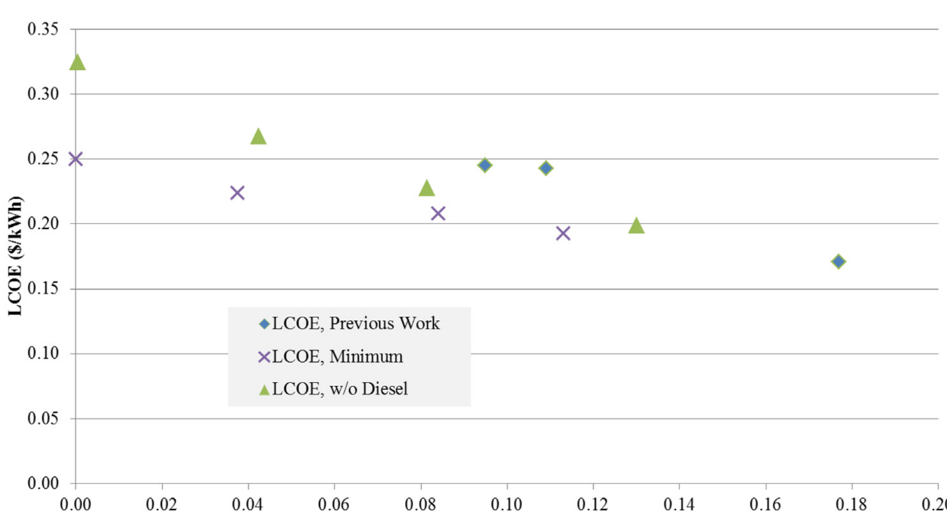



**Fig. 7.** Cost of availability results. Previous results from non-optimized systems compared to optimal systems (LCOE Min) showing the lowest cost solutions for each availability level, (Options 2–5) and optimal systems not allowing diesel (LCOE w/o Diesel) showing renewable only solutions (Options 2b–5b).

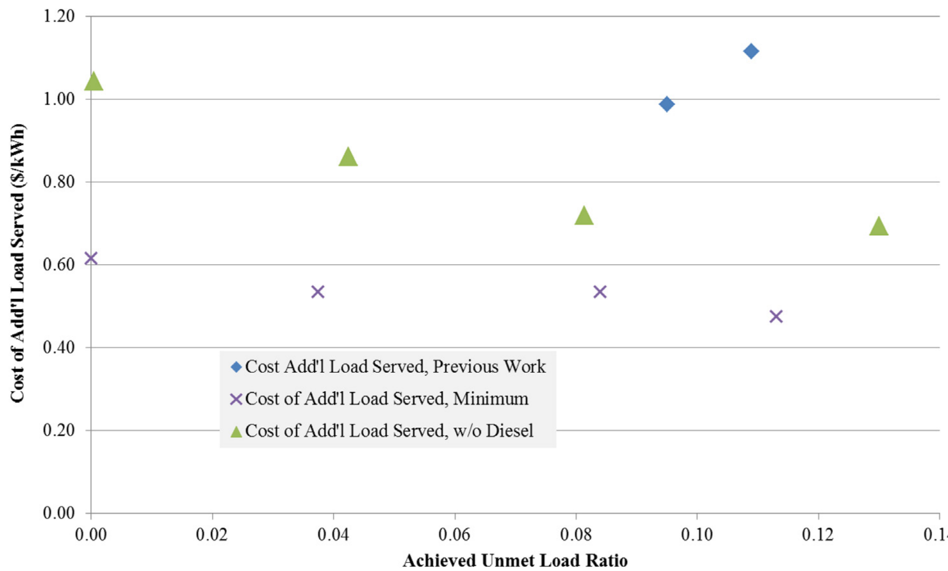



**Fig. 8.** Cost of additional load served beyond that provided by an unreliable grid (Option 1M) for minimum cost and renewable only options.

The economically preferred option for zero allowed downtime, Option 5, adds batteries to augment the generator used in Option 4.

The no-diesel constraints in Options 2b–5b further increase the cost of additional load at each availability level. The increased cost is enough such that the cost of addition load at an unmet load ratio of 0.15 is higher than the diesel allowed cost at a 0.00 allowed unmet load ratio. Of note, Option 3b uses no solar power generation to meet the constraint but instead meets the constraint with a battery backup solution at an LCOE of $0.228/kWh.

Solar and battery alternatives are of great importance in decreasing the level of GHG (greenhouse gas) emissions and therefore these options might come cheaper in the future if the cost of emissions is accounted for with the introduction of emission costs. This is possible since it is now widely recognized that GHG emissions resulting from the use of a particular energy technology need to be quantified [36].

### 3.3. Observations

#### 3.3.1. Importance of considering random failure and recovery times in systems optimization

Mahapatra and S. Dasappa [23], as noted previously, considered grid availability but only the average availability time, with a comparison of 6 h/day, 8 h/day and 12 h/day systems. By Equation (1), these would correspond to availability rates of $A = 0.75$, 0.667 and 0.5, but MTTR and MTBF were not considered. The potential shortcoming of considering only the average availability rate in modeling and analysis is illustrated by Option 3 in Table 3. Consider a battery bank designed to meet the average outage duration and frequency and to provide the average power demand over that outage. An average outage of 10.1 h, with an average power demand of 25.7 kW would give 260 kWh of load unmet during an average outage.

Given a useful capacity per Surrette 6CS25P battery of 4.16 kWh [25], then 260 kWh/4.16 kWh/battery would require 62.4 batteries, with the first integer solution for a 12 V system at 32 strings of 2 batteries, or 64 batteries total. If the outages were all 10.1 h long, and occurred against a constant average load of 25.7 kW, this solution would be optimal. But because the outages are stochastic and the load is not constant, in simulation this solution (which is identical to Option 3b in Table 3) still leaves more than 8% of the load unmet. To achieve 100% availability with a grid and a battery only solution in this outage environment would require 512 batteries and an LCOE of $0.51 – more than double the LCOE in Option 3b. Clearly backup systems designed to meet the average outage and power will fail to meet the demands of real world systems; stochastic variation in outage and recovery time must be considered.

#### 3.3.2. Grid interactions

Only Option 5b decreases grid consumption significantly. Option 2b introduces a small decrease, but only by 62 kWh/yr. Scenarios 3 and 4, in both solar and renewable only options, all have optimal solutions that increase grid consumption by at least 5%. The increase in grid consumption occurs because battery storage enables the systems to shift grid power to times when the grid has failed, which increases the hours of consumption and the total consumption. Battery use also incurs energy loss in the round-trip conversion to and from battery storage, and so can even increase the total consumption beyond the original demand. While Options 2–5 supplement the grid while it is down by providing diesel power as a backup, they do not decrease consumption from the grid because when the grid is operational, it is still the cheapest source of electricity in these scenarios so diesel will not offset grid use while the grid is operational.

For that reason, none of these options can economically sell electricity back to the grid at the rates provided, as the cost of diesel production is at least $0.32/kWh, which exceeds the feed in tariffs of less than $0.120/kWh.

As a result, each of these options may be viable local solutions, but broadly applied could actually decrease regional grid reliability as they increase consumption but do not provide any increased generation capacity to the grid. This could create new grid outages from generation shortfalls. The local utility would likely force such installations to become stand-alone micro-grids as to avoid the negative consequences on the grid system, such as changing the system from a passive to an active network, increasing system losses, lowering the voltage profile below the allowable limit, and thus decreasing the overall availability and operation of the power system network [37].

Option 5b is the only one that sells a significant amount of electricity back to the grid, and decreases overall grid consumption.

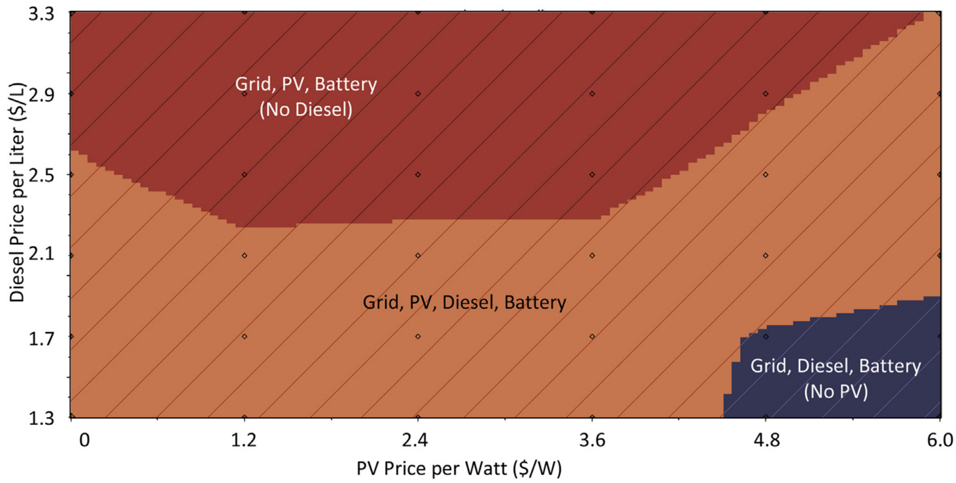



**Fig. 9.** Optimal system configurations determined in HOMER simulation for increasing fuel prices and decreasing PV prices.

Of the scenarios and options examined, only Option 5b could potentially mitigate local and national capacity shortages. Once installed, the marginal cost of solar electricity is near zero, and so the Option 5b can economically offset some grid purchases, and even sell power back to the grid, as shown in Column K. The broader grid impacts bear further analysis, but are outside the scope of the HOMER tool and this paper.

*3.3.3. Hybrid solutions to adapt to changing energy prices*

When considering renewable solutions only, Options 4b and 5b show a significant cost increase to achieve the availability constraints in Scenarios 4 and 5. The difference is particularly stark in the 100% availability requirement for Scenario 5. LCOE for a PV system in Scenario 5 (Option 5b) is $0.075/kWh more than the Option 5 LCOE at $0.325/kWh. On a per additional kWh served basis, Option 5b costs $0.426/kWh more than Option 5 at just over $1.00/kWh for Option 5b. This highlights the economic challenge for renewable options at current prices.

The result, though, is based on a fixed price for grid, diesel and solar over the 20 year lifecycle analysis in the HOMER simulation, but prices for solar have been decreasing while diesel has become more expensive. [38] To replicate the data from previous work, we used the $6/W from that analysis [24], but high quality panels are available in Kampala, Uganda for less than $3/W in 2013, and this is consistent with world prices [39]. Meanwhile, diesel and grid electricity prices are expected to rise over the 20 years of this system lifecycle, with a baseline expectation of a 30% increase and a high-side estimate of a 60% increase in diesel prices by 2030 [4,40]. Szabó notes that the optimal system is extremely sensitive to diesel fuel costs and diesel subsidies, and that PV electricity is at the margin to become competitive with diesel and with grid electricity for larger populations in remote areas [17].

While HOMER does not support the ability to simulate an inflation rate for fuel prices that is higher than the general inflation rate, we can run sensitivity analysis on the price of diesel to examine possible impacts of a 30% and 60% increase in the price of diesel against the baseline price used in simulation. Note that this price increase holds throughout the simulation, so cannot exactly replicate a fuel inflation rate. For comparison, we re-examine Scenario 4 (0.05 allowable capacity shortage ratio) at various fuel prices and PV panel costs. A range of diesel costs from current prices of $1.30/L up through 2.5 times that to $3.30/L are considered. Solar PV costs per Watt are examined from the baseline of $6/Watt using HOMER's "PV capital cost multiplier" function to study PV costs reductions of 0.8, 0.6, 0.4, and 0.2 times current prices ($4.8/W, $3.6/W, $2.4/W, and $1.2/W respectively).

A clear summary of the impact of diesel price increases and PV price decreases can be seen in Fig. 9. The baseline price of diesel and PV panels is in the bottom right corner ($6/W, $1.3/L). Even at high PV prices, as diesel prices increase up the *Y* axis, it takes a 50% increase in fuel prices to $1.9/L to move into a regime where solar PV becomes part of the optimal solution. Not until diesel prices exceed $3.3/L does diesel generation drop out of the optimal systems mix to achieve a 95% availability rate.

Leaving fuel prices alone, but considering less expensive PV, one moves left along the bottom of the chart to see that PV prices need only to drop by just over 20% to $4.4/W for PV to become part of the optimal system configuration. Considering that PV prices have already dropped to less than $3/W, PV looks to be part of the optimal systems configuration now and in the future. Taking a closer look at the systems optimization for a diesel price of $1.7/L and a PV price of $2.4/W, the optimal configuration to meet the 5% capacity shortage constraint is a 50 kW PV array, 10 kW diesel generator, 32 Surrette batteries and a 40 kW inverter with a resulting LCOE of $0.201. This optimal configuration holds even as diesel prices increase to $2.1/L.

In sum, hybrid PV/diesel/battery solutions offer some adaptability to increasing fossil fuel prices, and have become more affordable and competitive as PV prices have decreased. The $0.201/kWh LCOE resulting using current PV prices in Uganda is even becoming competitive with the $0.171/kWh cost of grid electricity.

## 4. Conclusions

Providing reliable and eventually clean and renewable electricity to the 20% of the world's population that lacks access to a grid is a daunting challenge. The method presented here demonstrates how consideration of the existing grid availability can be included in cost benefit analyses of various systems for electricity production, and selecting optimal configurations for grid tied DER. This paper addresses this analytical shortfall to provide new methods to estimate the cost of reliable electricity and identify optimal systems configurations to provide more reliable electricity. Using the method to analyze potential systems configurations for a village power system in Uganda, results indicate that at current prices, diesel is the most economical choice for a backup system for the village. But, expected increases in diesel fuel costs and continuing decreases in solar PV prices make solar/diesel hybrid systems economically competitive with diesel backup systems in the long run. It is also noted that the improved availability and reliability results in increased cost of energy because some additional equipment have to be added to the system which elevates the cost of the whole system. However, the increased cost of energy is justifiable given the increase in reliability of power supply to the end user. The model and method hold for any region with an electric grid that is less than perfectly reliable.

## Role of the funding source

The generosity of the **Accenture Foundation** has supported this research, to include travel to Uganda to gather data and implement related efforts. Uganda travel, research and implementation parallel to this effort were performed as a member of the **Notre Dame Initiative for Global Development**, and their continuing support is much appreciated. NDIGD and the Accenture Foundation had no role in study design, data collection, analysis nor interpretation of data; nor in the writing of the report; nor in the decision to submit the article for publication.

## Appendix A. Supplementary data

Supplementary data related to this article can be found at http://dx.doi.org/10.1016/j.energy.2014.01.020.

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