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Maximising the benefits of renewable energy infrastructure in displacement settings: Optimising the operation of a solar-hybrid mini-grid for institutional and business users in Mahama Refugee Camp, Rwanda

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ABSTRACT

Humanitarian organisations typically rely on expensive, polluting diesel generators to provide power for services in refugee camps, whilst camp residents often have no access to electricity. Integrating solar and battery storage capacity into existing diesel-based systems can provide significant cost and emissions savings and offer an opportunity to provide power to displaced communities. By analysing monitored demand data and using computational energy system modelling, we assess the savings made possible by the integration of solar (18.4 kW_p) and battery (78 kWh) capacity into the existing diesel-powered mini-grid in Mahama Refugee Camp, Rwanda. We find that the renewables infrastructure reduces fuel expenditure by $41,500 and emissions by 44 tCO_{2eq} (both 74%) over five years under the generator's current operational strategy. An alternative strategy, with deeper battery cycling, unlocks further savings of $4100 and 12.4 tCO_{2eq}, using 33% of battery lifetime versus 15% under the original strategy. This reduces the cost of electricity by 33% versus diesel generation alone, whilst more aggressive cycling strategies could prove economical if moderate battery price decreases are realised. Extending the system to businesses in the camp marketplace can completely offset the system fuel costs if the mini-grid company charges customers the same tariff as the one it uses in the host community, but not the national grid tariff. Humanitarian organisations and the private sector should explore opportunities to integrate renewables into existing diesel-based infrastructure, and optimise its performance once installed, to reduce costs and emissions and provide meaningful livelihood opportunities to displaced communities.

1. Introduction

Approximately 800 million people remain without electricity globally, and this number is set to increase for the first time since 2011 owing to the COVID-19 crisis [1]. Meanwhile more than 80 million people are estimated to be forcibly displaced for reasons such as conflict and violence in their place of origin, a number which has more than doubled from a decade ago [2]. Energy usage and access is not yet well understood in displacement settings, in part due to a lack of data [3]; however, it is estimated that only around 10% of those living in camps for displaced people have access to reliable energy sources. Most rely primarily on fuels that damage the environment and human health, such as locally sourced biomass for cooking, and have little or no access to electricity [4,5].

Organisations that deliver humanitarian support to displaced people, such as the United Nations High Commissioner for Refugees (UNHCR), typically use diesel generators to power their institutional functions within camps: this has high costs and results in significant harmful greenhouse gas (GHG) emissions [6]. Renewables-based mini-grids are increasingly being deployed in Sub-Saharan Africa to provide electricity access to rural communities [7] and also offer great potential to be used in camps to reduce fuel usage, as well as provide electricity access for displaced people where a connection to the national grid may not be affordable or even permitted [8–10].

Hybrid mini-grids – independent systems which combine renewables, battery storage and dispatched generation such as diesel to serve local electricity demands – are often more economical at high levels of reliability than those supplied either by solar photovoltaics (PV) or

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Nomenclature

Abbreviations

AC	Alternating current
ARC	American Refugee Committee
CC	Cycle charging
CD	Combined Dispatch
CLOVER	Continuous Lifetime Optimisation of Variable Electricity Resources
CRRF	Comprehensive Refugee Response Framework
DC	Direct current
ESMAP	Energy Sector Management Assistance Program
gCO_{2eq}	Grams of carbon dioxide equivalent
GHG	Greenhouse gas
GPA	Global Platform for Action
HEED	Humanitarian Engineering and Energy for Displacement
kWh	Kilowatt hour
kW_p	Kilowatt peak
LCOE	Levelised cost of electricity
LCUE	Levelised cost of used electricity
LF	Load following
MINEMA	Ministry in Charge of Emergency Management
NGO	Non-governmental organisation
NPC	Net present cost
PV	Photovoltaics
RE4R	Renewable Energy for Refugees
RWF	Rwandan Francs
SDG	Sustainable Development Goals
SOC	State of Charge
tCO_{2eq}	Tonnes of carbon dioxide equivalent
UNHCR	The United Nations High Commissioner for Refugees
VRM	Victron Remote Management

Notations and Units

Energy	
from PV	E^{PV} (kWh)
balance	E^{Bal} (kWh)
from diesel to battery (max)	E^{DBat}_{max} (kWh)
from diesel to battery	E^{D}_{Bat} (kWh)
from PV to battery	E^{PV}_{Bat} (kWh)
from PV used directly	E^{PV}_{dir} (kWh)
Storage capacity	B (kWh)
Diesel	
capacity	D (kW)
times	$D_{on}(t)$ ({0,1})
load factor, min	Γ, Γ_{min} (%)
max, min output	E^{D}_{min}, E^{D}_{max} (kWh)
Diesel threshold SOC	$S_{Thr}(t)$ (%)
Energy from source i	$S^{i}(t)$ (kWh)
Monitored load	$L^{M}(t)$ (kWh)
mean	μ^{M}_{h} (kWh)
standard deviation	σ^{M}_{h} (kWh)
Business load	$L^{B}_{N}(t)$ (kWh)
of type b	$L^{b}_{n}(t)$ (kWh)
Total load	$L^{T}_{N}(t)$ (kWh)
Cost (total)	C^{T} ($)
of type j in year n	C^{j}_{n} (kWh)
Discounted energy	E^{T}_{Disc} (kWh)
LCUE	L ($/kWh)
Battery health	$H_k(t)$ (%)
cycle life	ξ_k (–)
Probability generator is on	$P^{G}(t)$ (–)
Energy of load	E^{L} (kWh)
unmet	E^{U} (kWh)
of diesel (surplus)	E^{D}_{Sur} (kWh)
diesel (generated)	E^{D}_{Gen} (kWh)
supplied by battery	$E^{B}_{Sup}(t)$ (kWh)
Empty capacity	E^{ec} (kWh)
Timestep of simulation	t (–)
C-rate in, out	C_{in}, C_{out} (%)
State of charge (SOC)	$S(t)$ (%)
max, min	S_{max}, S_{min} (%)
switch-on, -off	S_{on}, S_{off} (%)
during quiet hours	S^{Q}_{on}, S^{Q}_{off} (%)
during diesel hours	S^{D}_{on}, S^{D}_{off} (%)
Synthesised load	$L^{S}(t)$ (kWh)
mean	μ^{S}_{h} (kWh)
standard deviation	σ^{S}_{h} (kWh)
No. businesses in total	N (–)
of type b	n_b (–)
Energy in year n	E_n (kWh)
GHG emissions (total)	G^{T} (tCO_{2eq})
of type j in year n	G^{j}_{n} (tCO_{2eq})
Discount rate	r (%)
Emissions intensity	g (gCO_{2eq}/kWh)
Battery throughput	$E^{Bat}_{Cum}(t)$ (kWh)
depth of discharge	δ_k (%)
On/off status of generator	$G^{on}(t)$ ({0,1})

diesel alone [11,12]. Appropriately sizing the components of hybrid mini-grid systems is important for both cost efficiency and ensuring system reliability [13]. Furthermore, how mini-grids are operated can affect their viability: fuel usage and battery degradation may vary significantly depending on the operational strategy, demand profile and renewable resource availability [14]. Compared to system sizing, research into hybrid mini-grid operation is relatively overlooked.

Hybrid mini-grids therefore offer the potential to meet the need for electricity in displacement situations but, as their deployment is not yet widespread, research is required to evaluate options for their implementation and their associated financial and environmental impacts. Furthermore, as their adoption is expected to increase, it is important to understand in the early stages how best to operate such systems to ensure any potential savings are replicated during scale-up.

To investigate the convergent issues highlighted above, new research should address three main questions:

1. How do present diesel-based electricity systems meet the demands of humanitarian actors and with what impacts, and how could future solar-diesel hybrid systems improve on them?
2. How could the operational strategies of hybrid systems be optimised, such as through altering generator usage times and

battery depths of discharge, to minimise costs whilst maintaining the reliability of supply?
3. What is the impact of extending access to the system to new users, such as refugee businesses?

Informed responses to these questions can contribute our aims of quantifying the benefits of renewable energy infrastructure in displacement settings and providing recommendations to inform the future implementation of such systems in similar contexts.

We assess the operation and performance of a hybrid solar, diesel and battery mini-grid system installed in Mahama Refugee Camp, the largest in Rwanda. Using energy modelling and high-resolution measured consumption data, we explore opportunities to reduce operating costs of the installed system by increasing the utilisation of renewable energy and reducing diesel fuel usage, whilst considering the impact on the lifespan of the batteries. We also evaluate the impact of connecting refugee business customers to the system, giving estimates of the additional resource needed for different numbers of customers. Finally we consider a range of possible tariff structures, and the extent to which they would mitigate any additional diesel costs arising from supplying the business connections. The paper proceeds as follows: Section 2 provides the context and literature related to this work, Section 3 presents the methodological framework and energy system model used to simulate the system, Section 4 presents the results of the analysis, and Section 5 summarises our findings and offers recommendations for this system and future implementation projects.

2. Literature review

2.1. Operating hybrid mini-grids

Three main solutions exist for providing electricity to unserved populations: extension of the national grid, isolated and independently operating electricity networks (e.g. mini-grids), or stand-alone systems, with factors such as terrain and population density governing the suitability of each for a given context [15]. The majority of people without electricity access live in rural communities [16] that may have low population densities or be geographically challenging settings which can make grid extension costly on a per-connection basis [17]. Mini-grids may therefore be better suited for serving areas that are relatively densely populated but that are located far from the main grid. Around 50 million people are already connected to mini-grids, with this number expected to rise tenfold by 2030 [7]. Most new capacity is expected to be in Sub-Saharan Africa and these mini-grids are increasingly incorporating hybrid PV-diesel configurations, in favour of those powered solely by fossil fuels [7], and so further research is needed into how best to implement these hybrid systems to support energy access.

For national electricity grids composed of many generators with different marginal costs of output, system operators will employ economic dispatch by meeting demand using the available generator(s) with the lowest marginal cost [18]. For a hybrid mini-grid with dispatched generation the aim will also be to meet demand at the lowest marginal cost but, in the absence of an active system operator, using a dispatch strategy with predetermined settings is often used [14].

Dispatch strategies include "load following" (LF) which is where the dispatched generator is operated to provide the net remaining demand if the renewables and batteries are insufficient. Under this strategy, the generator is not used to charge the batteries, but only to meet the load directly [19]. Alternatively, "cycle charging" (CC) means that the generator is used to charge the batteries, and may also meet demand simultaneously. This can have operational benefits: high capacity factors, increased efficiency and therefore reduced fuel use per unit output, and the number of generator starts may also be lower, further reducing fuel consumption and maintenance costs [20]. CC can reduce the total hours that the generator runs, and can respect the desire for "quiet hours", as is the case for the system described in this paper. However, CC increases the energy throughput of the battery, increasing degradation and representing a financial burden if the batteries must be replaced sooner. Additionally, the strategy may result in renewable energy being dumped rather than stored if battery capacity is used to store dispatched generation instead [14]. Finally a "combined dispatch" (CD) strategy, whereby the generator may operate either as load following and cycle charging under different conditions, is possible and aims to maximise possible benefits of both LF and CC strategies [19]. This requires a net load threshold to be calculated at which it is more costly to discharge the battery than run the diesel generator to meet net load. The system then switches between CC and LF modes during operation according to the demand level.

The large number of variables that can affect the lifetime cost of hybrid mini-grids mean there has been significant literature devoted to their optimal sizing [21–23] and operation [19,24–26]. Much literature focuses on the application of different algorithms (such as genetic, particle swarm and heuristic algorithms) to their sizing and operation, a comprehensive review of which is available in Saharia et al. [27]. For hybrid mini-grid operation that includes CC, important variables are the points at which the battery state of charge (SOC) is considered low enough that the dispatched generator will turn on, and high enough that it will turn off. These battery SOC "set points" can significantly affect the lifetime cost of a system [28,29].

In support of understanding the impacts of these variables, many tools have been developed to simulate or optimise the operational strategy of hybrid mini-grids. iHOGA uses a genetic optimisation algorithm and can optimise both system size and the battery SOC set points in a CC strategy [30]. HOMER, the widely used commercial tool, can also be used with MATLAB link to simulate different user-defined dispatch strategies that adjust the SOC set points [31]. Hybrid2 offers a wide range of dispatch options but does not have an optimisation function [32]. Importantly for replicable and verifiable academic research, and this work specifically, the software tool used to evaluate different operational strategies or parameters should (a) be able to accurately model the real-life system, (b) have a transparent (ideally open-source) code base, and (c) be able to optimise for chosen parameters. Of these tools none meet all three criteria however another existing energy system model, CLOVER, can be modified to meet these needs as described in detail in Section 3.4.

Studies that investigate improved operation of hybrid mini-grids are limited and have mixed findings. Arévalo-Cordero et al. [33] and Ramesh and Saini [34] conclude that a CD strategy offers the lowest cost of electricity, whilst others [19,26,35–37] found the CC strategy to be the most economical. Das and Zaman [38] find almost no difference in cost of energy between the three main dispatch strategies. Although Bernal-Agustín et al. [39] in their optimisation of size and operational strategy found the lowest unit cost of electricity to be from a CD strategy, the CC strategies investigated give the lowest diesel costs. Few studies adjust the battery SOC set points for operation that includes cycle charging, which limits their findings. For those that do [14,19,39], different optimal values are found, given variation in storage technology used and the shape of the demand curve. These studies suggest the potential for a study into using a CC strategy to reduce diesel costs under a variety of SOC set points and also its dependence on the case study under investigation which, given the lack of previous application of this research to displacement settings, highlights a research gap for our work.

2.2. Energy in displacement settings

If the number of people displaced globally continues to rise at the current rate then there will be more than a quarter of a billion people displaced by 2030 [40]. Extreme weather events caused by climate change are likely to trigger increased involuntary migration in future years [41], and more than 200 million people could be internally displaced by climate change alone by 2050 [42] causing increased pressure on humanitarian organisations. Protracted crises often lead to long-term displacement, averaging 10 years for refugees, with little change to this over the last three decades [43]. Consequently, temporary settlements can be occupied for many years and require appropriate infrastructure and services to function [44].

The vast majority of refugees are hosted in developing countries [2], and often in remote, geographically challenging environments where access to modern energy services is limited [6]. The Moving Energy Initiative estimated that as many as 20,000 displaced people die per year as a result of indoor air pollution caused by lack of modern energy services, mainly for cooking [4]. A lack of electricity, meanwhile, has an impact on livelihoods as it limits the capacity of displaced people to carry out income-generating activities that may improve their quality of life [45,46]. Coupled with the protracted nature of many displacement contexts, there is therefore a need for long-term solutions to provide the benefits of clean energy access in these settings.

More recent recognition of a lack of energy services for displaced people has led to a greater focus from relevant organisations and in 2018, displaced people were explicitly included in SDG 7 [47]. In support of this, the Global Platform for Action on Sustainable Energy in Displacement Settings (GPA) is an initiative that promotes actions that enable affordable, sustainable and reliable energy services for displaced populations and their host communities and has the support of more than 50 international organisations and member states [48].

Recently, humanitarian organisations have developed targets to reduce their environmental footprint. UNHCR, for example, operates over 3000 diesel generators powering vital institutional functions such as health clinics in camps [49]: acknowledging the GHG emissions that result from this, UNHCR has introduced initiatives to increase the use of renewable energy and reduce their diesel consumption [50]. These high-level commitments can provide institutional recognition of the need for sustainable energy solutions, which can be vital in initiating implementation projects in the field.

Diesel usage in humanitarian settings is also a significant cost burden. Transporting diesel to geographically challenging locations means that unit cost of electricity can be several times higher than the grid in a respective host county, and the humanitarian sector as a whole is estimated to spend $400 million per year on diesel fuel for electricity generation [6,51]. This expenditure is against a backdrop of funding difficulties for agencies working to support displaced people [52]; in 2020, for example, UNHCR faced a funding gap of 51% [53]. Assessing the potential cost savings of reducing the usage of diesel fuel can therefore provide compelling evidence in support of clean energy solutions.

Techno-economic studies offer an insight into addressing the financial, environmental and humanitarian need for more sustainable electricity. Frack et al. [54] estimated a payback time of 5.4 years for a solar PV, wind and storage system that replaces diesel generation for a refugee camp in Juba, South Sudan. Neves et al. [55] calculated that incorporating solar PV and batteries with existing diesel yields a payback period of 3.4 years for Mantapala refugee camp in Zambia, with GHG emissions reduced by 55% compared with the baseline of diesel alone. Baranda Alonso et al. [9] estimated that to completely displace diesel usage at Nyabiheke camp in Rwanda would result in the initial investment in PV and battery equipment being paid back after 6.2 years. A hybrid diesel-solar system, with no storage, that reduces diesel usage by 32% was found to have a payback period of 0.9 years.

A recent study by Baldi et al. [10] applied a macro-level techno-economic modelling approach to assess the energy needs of displaced households, businesses, and the institutions in 288 refugee settlements in Sub-Saharan Africa. Using this demand to design renewable energy solutions for each settlement, they found that the upper bound for the cumulative up-front cost of meeting the total demand would be $1.34 billion and, by deploying PV mini-grids in place of diesel, could offset 2.86 $MtCO_{2eq}$ over 20 years. The scale and scope of this study offers great insight into the cumulative potential of solar and hybrid mini-grids to provide power in displacement settings and, amongst its recommendations, stresses the importance of using reliable and representative data to inform future research.

The existing literature shows the potential for renewable energy mini-grids but has limitations. The first studies two use bottom-up approaches to estimate the electricity demand, rather than electronically monitored data, and all four assess the design of theoretical examples rather than implemented systems. Furthermore, these studies explore the configuration of system components but not the optimum operational strategy of a system already in place. As the number of these systems installed in displacement settings grows, it will be increasingly important for research to focus not only on design effective systems but also how to maximise their benefit following implementation.

Despite examples of PV reducing diesel usage in camps for displaced people there are significant barriers to broader deployment. Most critically, the short-term budgets and uncertainty over how long camps will exist impede the humanitarian sector from deploying more renewable generation [4,9,55]. Annual budget cycles prevent investment in the higher upfront costs of renewable energy technologies, even when they could save large amounts of money over the lifespan of a camp [55]. Involving the private sector can help to overcome some of the issues around long-term investments, and organisational commitments are beginning to be addressed via standard contractual terminology [56] and guarantee mechanisms to de-risk private sector investment [57], but these are yet to be operationalised at scale. Central to this, however, is the necessity to explore and highlight opportunities to achieve or increase the profitability of these systems for private sector companies, which has not yet been well demonstrated.

A further barrier is the sparse data on the current energy sources and potential future energy demand of displaced people. This lack of data can inhibit the impact of energy interventions: a renewable energy system may be incorrectly sized, or connected only to a small number of key users to preserve reliability, but this could limit its benefits and its potential to be extended to other users in the camp, for example businesses or households [3]. It is therefore important to gather data from existing systems, understand their technical and economic performance, and explore opportunities to extend access to displaced people themselves in order to provide critical evidence to scale up sustainable electricity access in displacement settings [10,46,58].

2.3. Situation in Rwanda and Mahama refugee camp

The Government of Rwanda has ambitious plans for achieving SDG 7. Its plan for universal electrification expects that around half of new connections are to be from off-grid solutions, including 10% from mini-grids, which have featured in its electrification strategies since 2004 [59]. Rwanda also has a progressive attitude towards refugees: hosting around 127,000 displaced people as of August 2021 [60], the Government is an adopter of the New York Declaration for Refugees and the Comprehensive Refugee Response Framework (CRRF) [61,62]. These international agreements acknowledge the protracted situations that many displaced people face and aim to integrate them into host community societies, offering a relatively conducive environment for long-term sustainable energy solutions.

Energy access in refugee camps in Rwanda has been the subject of recent research. The Renewable Energy for Refugees (RE4R) Project, a collaboration between an NGO Practical Action and UNHCR, supported sustainable energy solutions in Gihembe, Kigeme and Nyabiheke refugee camps: as part of the initial assessments [63] it found that energy access amongst households and businesses was typically below the Government's target of Tier 2, as defined by the ESMAP Multi-Tier Framework [64]. Subsequent studies using those data analysed viability [65] and later diffusion [66] of solar home systems in the three camps, and monitored the electricity usage of the diesel mini-grid in Nyabiheke Camp [67] which was used to inform techno-economic modelling of potential solar and hybrid alternatives [9]. Research by the

Fig. 1. The health centre at Mahama Refugee Camp with the solar generation on the roof. Photograph courtesy of Arthur Santos and MeshPower Ltd.

Humanitarian Energy and Engineering for Development (HEED) project also researched energy access in the same three camps and shared energy surveying and monitored data [68]. The project evaluated the performance of its solar streetlight interventions in the camps [69] and stressed the importance of co-design with displaced communities to maximise the benefits and energy utilisation of solar interventions for community use [70].

This study builds on these works by assessing the case of the largest refugee camp in Rwanda, Mahama, and investigating the mini-grid which recently had solar and battery storage integrated into its system. Mahama Refugee Camp, located in Eastern Province, is home to approximately 46,000 refugees who fled conflict in Burundi since 2015 [60]. The Ministry in Charge of Emergency Management (MINEMA) and UNHCR oversee the camp administration and the protection of displaced people, whilst critical services are provided by NGO partners. The international nonprofit humanitarian aid organisation Alight, formerly the American Refugee Committee (ARC), has operated in Rwanda since 1994 and are responsible for infrastructure in the camp which includes the provision of electricity services for institutional users [71].

Before the upgrade of the electricity system, power was provided by diesel generators and available to a restricted group of users including the camp administration offices and the health clinic, which provides primary healthcare services. The provision of electricity in the camp was the responsibility of Alight and the fuel costs were covered by UNHCR, with the users receiving electricity at no cost. MeshPower Ltd., a solar mini-grid company, was contracted by Alight to install PV and battery storage to hybridise the existing system. The capital expenditure for hybridising the system was grant-funded by various donors with the intent of reducing fuel usage and costs. MeshPower operates more than 70 PV mini-grids around Rwanda serving domestic and commercial customers, and a smaller number of institutional users, via direct current (DC) connections for basic energy access and alternating current (AC) connections to support productive and more intensive electricity requirements [72]. In December 2019 MeshPower installed 18.4 kW_p of PV and 78 kWh of battery capacity at the Mahama health clinic to serve consumers via an AC distribution network (see Figs. 1 and 2). For the present study, MeshPower Ltd. provided access to the data remotely monitored from the system, guidance on its technical and operational aspects, and potential extension to refugee businesses, but had no influence on the results, conclusions or recommendations.

The electricity system is configured so the that PV and diesel generator are used to meet the load, and also to charge the batteries. The diesel generator operates using a CC strategy, with the SOC set points dictating when the charging occurs depending on the time of day. Late at night, noise from the generator must be avoided where possible: during these times the SOC set points are configured such that the generator is run only in exceptional circumstances when the state of charge of the battery is very low. Earlier in the evening, the settings ensure that (as required) the generator will charge the batteries to a higher SOC to provide electricity throughout the night. It is this requirement, to compress diesel generator operation into the earlier evening, that partly necessitates a CC strategy.

Since the integration of the solar and battery capacity into the system in December 2019 the electricity demand has increased to accommodate additional loads in the health centre (including a recently constructed maternity centre), connections for further offices and the camp police station, and new street lighting in the nearby area. In addition, refugee businesses in the nearby marketplace will be connected to the system and supplied with AC power on a commercial basis under a tariff structure, with any additional system fuel costs being covered by MeshPower.

In this paper we consider the different objectives of each of the key stakeholders: reducing fuel costs and GHG emissions (Alight), ensuring system reliability and optimal performance (MeshPower), providing improved opportunities for livelihoods in the camp (UNHCR, MINEMA and refugee entrepreneurs), and learning how to improve the design or operation of such systems in other situations of displacement (academics and the wider practitioner community).

3. Methodology

3.1. Overall approach and aims

Our overall methodology is listed below. Our primary objective was to reduce the fuel usage of the diesel generator (particularly overnight) by increasing the utilisation of the solar and battery storage capacity, whilst maintaining adequate performance of the system. Our secondary objective is to quantify the additional impacts of providing electricity for refugee businesses. To do this we:

1. Analysed data collected from the Mahama Camp system,
2. Modified and used the CLOVER energy system model to emulate the system operation,
3. Quantified the performance, costs and GHGs impacts of (a) the original diesel-only system and (b) the solar-diesel hybrid system under its present operational strategy, and (c) the hybrid system under a range of potential strategies,
4. Evaluated the impact of different numbers of refugee business connections to the system.

From these results we drew conclusions and provided recommendations for the partners in Mahama Camp and stakeholders the wider energy and humanitarian sectors.

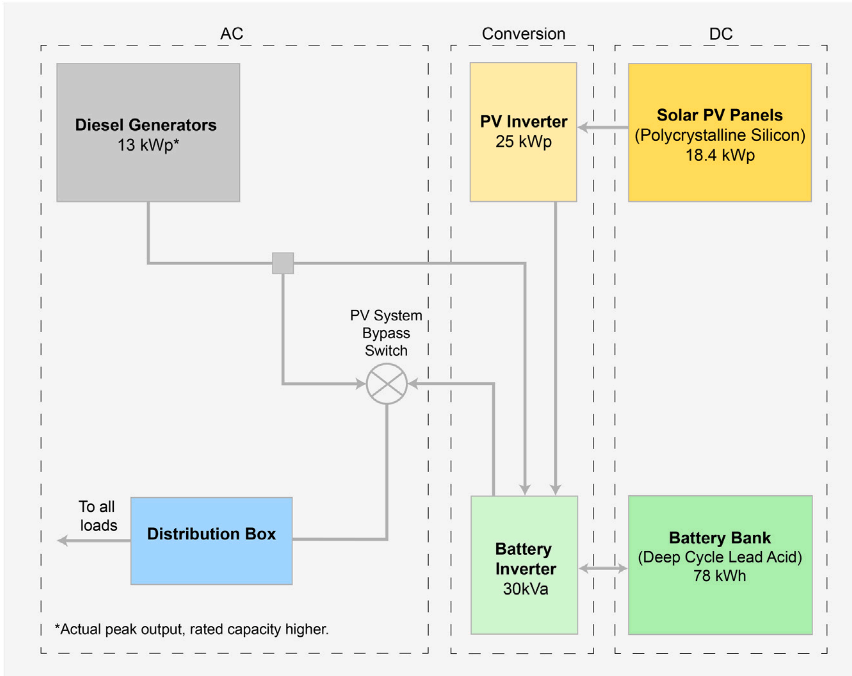

Fig. 2. A simplified system diagram of the electricity system at Mahama Refugee Camp which shows the original diesel capacity (grey), and the solar PV (yellow) and battery storage (green) equipment installed by MeshPower Ltd. Arrows indicate the direction of energy flows.

3.2. Analysing data from the mahama system

Electricity usage and operational data from the Mahama system is remotely monitored and stored via the Victron Remote Management (VRM) energy monitoring platform. Data is recorded at a minute or hour resolution, with the latter used in this analysis for congruence with our modelling approach. The data is segregated by the energy source (diesel generator, PV or battery storage) and destination (consumers or battery charging).

We used the total load supplied by the system from all sources, which was monitored from 1 January 2020 to 31 December 2020, to synthesise the load profile for institutional users. First we derived the mean and standard deviation of the monitored data for each hour of the day. To synthesise a new load profile as an input for the modelling process, we selected values from a normal distribution for the corresponding hour of the day for each hour of a five-year period. This yields a profile which emulates the hourly variation of the original monitored data, but is seasonally invariant. Our process is described in detail in the Supplementary Information (B.1.1).

3.3. Load profiles of refugee businesses

In addition to the load profile of the institutional energy users in Mahama Camp we also consider the additional loads of refugee-owned and -operated businesses in the nearby camp marketplace. We do this by considering several cumulative load profiles for a total of N business connections, which allows us to evaluate the impact of extending electricity access at different scales. A full description of how the business load profiles were constructed is available in the Supplementary Information B.1.2.

We used a qualitative survey of 142 refugee business, conducted in Mahama in January 2019, to provide an indication of the types of businesses operating in the camp [73]. This allowed us to estimate the existing distribution of business types and those to be modelled in this work. Monitored electricity use data from refugee businesses in the camp was not available, as they did not have connections to monitor, and so to derive the load profiles of the businesses we used data from 19 businesses provided by MeshPower Ltd. These business customers are served by a mini-grid operated by MeshPower in the village of Gitaraga, situated in a rural area outside of the Rwandan capital Kigali. Businesses in this site are similar to those found in the camp and in other displacement situations [46,63]. Their energy usage has been monitored by MeshPower as part of their usual business operations and are considered representative of both refugee businesses and future MeshPower customers. Data from the Gitaraga site was processed similarly to that in Section 3.2 to calculate the hourly means and standard deviations of each business type [74].

Table 1
The breakdown of the businesses in the marketplace in Mahama Camp found by the surveys (“Survey %”), the simplified proportions used in this work (“Modelling %”), and a description of their operations.

Business type	Survey %	Modelling %	Description
Bar/Restaurant	48	50	Food, refreshments and entertainment
Shop	24	15	Sells food and small items
Tailor	7	10	Clothes production and repair
Hair salon	8	10	Hairdressing and barber services
Device repair	4	–	Electronic and device repair services
Money transfer	7	–	Accounting and money transfer services
Cinema	2	5	Television, football matches and films
Workshop	–	10	Welding and device repair services

Table 1 gives a breakdown of the types of businesses operating in the Mahama marketplace found by the surveys (“Survey %”) and the simplified proportions used in our model to ensure integer numbers of businesses (“Modelling %”). The proportions of shops and money transfer agents were reduced slightly in favour of an increase in the proportion of workshops (also including phone and device repairs), cinemas and tailors to better reflect the potential makeup of a marketplace with increased access to electricity.

We consider the synthesised system load profile with low, medium and high levels of business connections, corresponding to $N \in \{20, 50, 100\}$. In alignment with the UNHCR goal of providing Tier 2 electricity access to displaced households, the magnitudes of the synthesised load profiles were scaled to provide 200 Wh per day for each business

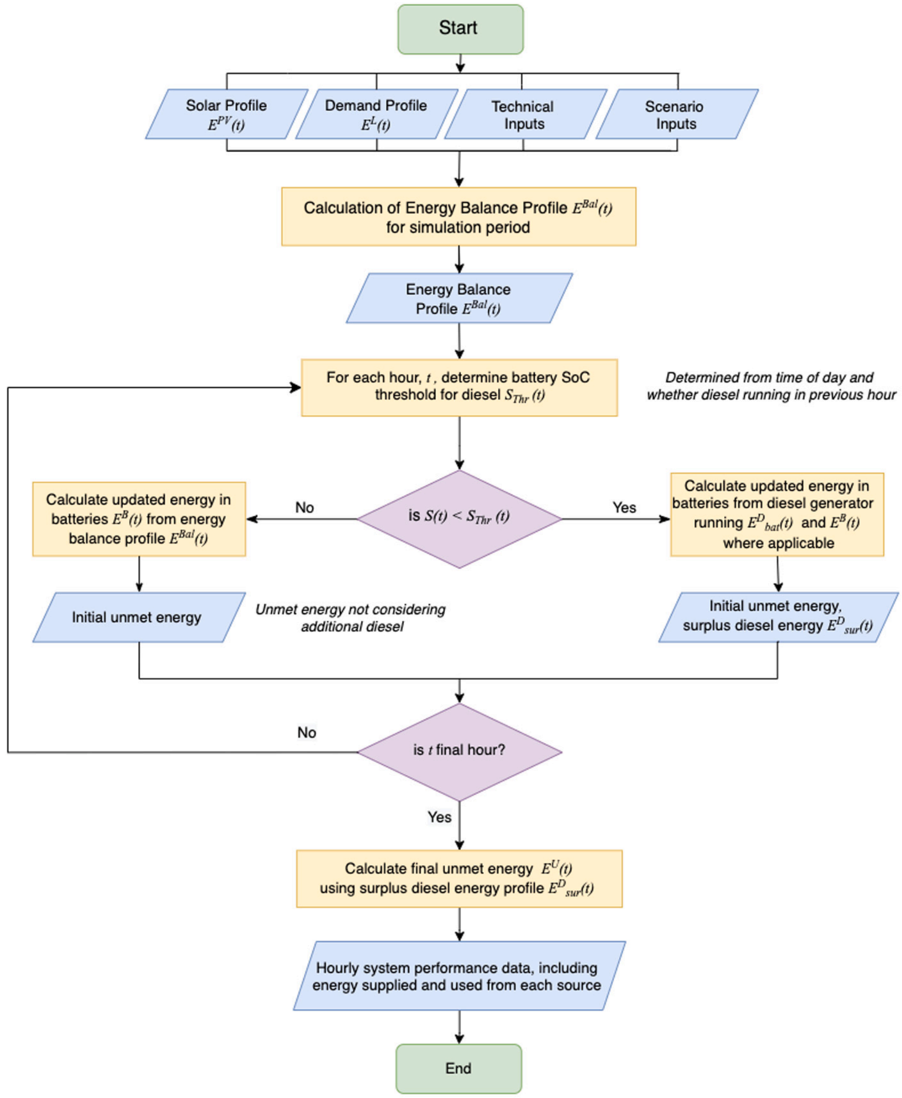

Fig. 3. A flowchart outlining the dispatchable diesel algorithm used in the energy system modelling.

user whilst the relative temporal variation remained the same. This may overestimate the energy use of businesses, as those in Gitaraga regularly used less than this amount [74], but nonetheless represents the energy requirements necessary to meet this Tier 2 goal.

3.4. Modelling diesel generation

As presented in Section 2.1, the software tool used in academic research should model the real-life system faithfully, should have an open-source code base available to others to replicate the study, and should be able to optimise for chosen parameters. Following these principles we adapted an existing open-source energy model that we developed and previously used, CLOVER[1] ("Continuous Lifetime Optimisation of Variable Electricity Resources") [75,76], to emulate the system at Mahama Refugee Camp. These new modifications enabled us to satisfy the first criterion, with the latter two already met by the existing modelling framework. Making these changes, described in this section, allowed us to simulate and explore the impacts of many different operational strategies before implementing any changes in practice, avoiding causing potential outages or disruption on the real system.

The CLOVER model is written in Python and can be used to simulate and optimise off-grid energy systems that comprise any combination of solar photovoltaics, battery storage, diesel back-up and an intermittent national grid connection [9,74,77,78]. We adapted the CLOVER model to introduce novel functionalities representative of the operation of the Mahama system. The new functionality means that the use of the diesel generator can be modelled using a CC dispatch strategy and that the specific SOC set points determining whether the generator will run can vary in different parts of the day (see Fig. 3). The following subsections mathematically outline the general operation of the model and the new capabilities integrated for this research. The accompanying code is available on Github[2]. For clarity this description does not include transmission and conversion efficiencies, or the degradation of batteries or solar panels, but these are accounted for in the model code.

3.4.1. Creation of energy balance profile

CLOVER uses the coordinates of the system location, the user-specified PV capacity, and its orientation (tilt and azimuth) to extract hourly solar generation data from the Renewables.ninja API. Renewables.ninja uses reanalysis data from the MERRA-2 dataset [79] and

[1] https://github.com/clover-energy/CLOVER

[2] https://github.com/hamishbeath/CLOVER

Table 2
Technical inputs for CLOVER simulations which were fixed.

Item	Value	Unit
Diesel capacity (D)	13.0	kW
Diesel minimum load factor (Γ_{min})	35	%
Diesel fuel consumption	0.31	L/kW/h
Battery capacity (B)	78	kWh
Battery charging C-rate (C_{in})	0.13	/h
Battery discharging C-rate (C_{out})	0.2	/h
Battery leakage	0.13	%/h
Battery conversion efficiency (in)	96	%
Battery conversion efficiency (out)	96	%
PV capacity	18.4	kW_p

Table 3
Example technical inputs which varied between simulations.

Item	Value	Unit
Diesel hours ($D_{on}(t) = 1$)	18:00–00:00	Time of day
Diesel hours switch-on SOC (S^D_{on})	65	%
Diesel hours switch-off SOC (S^D_{off})	95	%
Quiet hours switch-on SOC (S^Q_{on})	45	%
Quiet hours switch-off SOC (S^Q_{off})	65	%

provides the estimated hourly solar generation profile for the system location, $E^{PV}(t)$.

CLOVER uses an hourly load profile $E^L(t)$, generated as described in Sections 3.2 and 3.3, and $E^{PV}(t)$ to create an hourly energy balance profile, $E^{Bal}(t)$, for the simulation period:

$$E^{Bal}(t) = E^{PV}(t) - E^L(t) \tag{1}$$

The resultant $E^{Bal}(t)$ represents the deficit or surplus of energy when considering the load and PV generation only. If positive there is surplus energy which may be stored, depending on the battery SOC; if negative there is an energy deficit which may be satisfied by energy in the battery or from diesel generators under certain conditions. If energy is available from neither source then there is unmet energy for that hour, $E^U(t) > 0$, and the model records a blackout.

$E^{Bal}(t)$ is used to simulate how the system will operate over its lifetime once the battery storage capacity B and the diesel generating capacity D, and their respective settings for operation, are considered. The inputs which are the same for every simulation are given in Table 2.

3.4.2. Determining the inclusion of the diesel generator

To determine whether diesel generation is used in any given hour, t, the model checks whether the battery SOC $S(t)$ is within a specified range (see Table 3), which varies on the time on the time of day, and whether the diesel generator was used in the previous hour $t-1$.

The SOC set points $S_{on}(t)$ and $S_{off}(t)$ represent the levels at which the generator will turn on and off and can be different depending on the hour of the day. During certain times the generator may be programmed to turn on at a higher state of charge, and therefore may be more likely to run than outside of those times. We refer to "diesel" hours (when the state of charge threshold is higher than usual) and "quiet" hours (all other times) to distinguish these two periods. Each has the relevant on and off set points S^D_{on}, S^D_{off} and S^Q_{on}, S^Q_{off} respectively.

Using the times of day set for "diesel" and "quiet" hours (see Table 3), CLOVER generates a binary profile $D_{on}(t)$ for the entire simulation. The profile $D_{on}(t)$ is used to attribute the relevant set points to each hour t. The minimum permitted state of charge, below which the diesel generator must turn on, is given by $S_{on}(t)$ where

$$S_{on}(t) = \begin{cases} S^D_{on} & \text{if } D_{on}(t) = 1 \\ S^Q_{on} & \text{otherwise} \end{cases} \tag{2}$$

and likewise the switch-off state of charge $S_{off}(t)$, which must be exceeded if the generator was running in the previous hour in order to charge the battery adequately, is given by

$$S_{off}(t) = \begin{cases} S^D_{off} & \text{if } D_{on}(t) = 1 \\ S^Q_{off} & \text{otherwise} \end{cases} \tag{3}$$

The battery SOC threshold, below which the diesel generator will run, is $S_{Thr}(t)$. During the hourly simulation (see Fig. 2), to determine which value – $S_{on}(t)$ or $S_{off}(t)$ – is the appropriate one for $S_{Thr}(t)$, the model checks whether the diesel generator was running in the previous hour by evaluating the value of diesel energy used by the batteries in the most recent time-step, $E^D_{bat}(t-1)$. The SOC threshold $S_{Thr}(t)$ is therefore defined by

$$S_{Thr}(t) = \begin{cases} S_{off}(t) & \text{if } E^D_{bat}(t-1) > 0 \\ S_{on}(t) & \text{otherwise} \end{cases} \tag{4}$$

3.4.3. Simulation process for hours when diesel not running

For hours where $S(t) > S_{Thr}(t)$, then the diesel generator will not run. The energy balance $E^{Bal}(t)$ then represents the potential flow of energy to (if positive) or from (if negative) the battery. This flow is constrained by the charging and discharging C-rates, C_{in} and C_{out} respectively, which are evaluated over the hour-long period for each timestep. The model first establishes the battery energy flow for the hour, $E^{Flw}_{Bat}(t)$, under the conditions

$$E^{Flw}_{Bat}(t) = \begin{cases} B\ C_{in} & \text{if } E^{Ba}(t) > B\ C_{in} \\ -B\ C_{out} & \text{if } E^{Ba}(t) < -B\ C_{out} \\ E^{Bal}(t) & \text{otherwise} \end{cases} \tag{5}$$

The battery energy flow E^{Flw}_{Bat} is added to the amount of energy in the batteries for the previous hour $E^B(t-1)$ to give $E^B(t)$, ensuring that the battery energy level stays within the minimum and maximum storage levels S_{min} and S_{max} and is given by

$$E^B(t) = \begin{cases} S_{min} B & \text{if } E^B(t-1) + E^{Flw}_{Bat}(t) < S_{min} B \\ S_{max} B & \text{if } E^B(t-1) + E^{Flw}_{Bat}(t) > S_{max} B \\ E^B(t-1) + E^{Flw}_{Bat}(t) & \text{Otherwise} \end{cases} \tag{6}$$

Any energy that cannot be stored due to the energy in the battery $E^B(t)$ or state of charge $S(t)$ exceeding the maximum S_{max} is dumped. The calculation of unmet energy is described later.

The battery energy supplied $E^B_{Sup}(t)$ is calculated, with non-zero values recorded for when the energy balance for the hour $E^{Bal}(t)$ is negative, i.e. when the battery is discharging energy, given by

$$E^B_{Sup}(t) = \begin{cases} E^B(t-1) - E^{Ba}(t) & \text{if } E^{Ba}(t) < 0 \\ 0 & \text{otherwise} \end{cases} \tag{7}$$

3.4.4. Simulation process for hours when diesel is running

When $S(t) < S_{Thr}(t)$ the diesel generator will run. The amount of energy generated by the diesel generator to charge the batteries depends on three factors: the empty usable capacity remaining in the batteries, $E^{ec}(t)$; the maximum diesel energy that can go from the diesel generator into the batteries, E^{DBat}_{max}, and the minimum load factor of the generator, Γ_{min}.

The presently-unused capacity $E^{ec}(t)$ is calculated using the total storage capacity B, the state of charge $S(t)$, and the maximum state of charge permitted for the batteries S_{max}, such that

$$E^{ec}(t) = B\ (S_{max} - S(t)) \tag{8}$$

Depending on the system configuration the maximum diesel energy that can go into the batteries in one hour, E^{DBat}_{max}, is constrained either by the maximum diesel generator output (E^D_{max}, the energy provided by the total diesel capacity D running for one hour) or the input battery C-rate, $B\ C_{in}$, whichever is smaller, such that

$$E^{DBat}_{max} = \min\left\{B\ C_{in}, E^D_{max}\right\} \tag{9}$$

The minimum load factor Γ_{min}, and the maximum energy E^D_{max} that installed diesel capacity D can produce in one hour determine the minimum possible output of the generator E^D_{min} via

$$E^D_{min} = \Gamma_{min}\ E^D_{max} \tag{10}$$

Given the above, the amount of energy supplied from the generator and *used* to charge the batteries $E^D_{bat}(t)$ is given by

$$E^D_{bat}(t) = \min\left\{E^{ec}(t), E^{DBat}_{max}\right\} \tag{11}$$

When the empty capacity $E^{ec}(t) < E^D_{min}$ some diesel energy *generated* is not used by the batteries and is either dumped or used to meet unmet demand. The value of the energy used to charge the batteries from the diesel generator, $E^D_{Bat}(t)$, is added to the amount of energy in the batteries from the previous hour, $E^B(t-1)$, to give an initial value for the amount of energy in the batteries for the current hour, $E^B_I(t)$, following the diesel charging.

When the maximum diesel energy that can go into the batteries is limited by the battery C-rate then any surplus solar energy is dumped. The initial battery energy $E^B_I(t)$ is confirmed as the final battery energy level for the hour, $E^B(t)$. When battery charging is instead limited by the maximum diesel output then it may be possible to charge the batteries further. Not yet considering S_{max}, the model calculates the energy that could be taken from the PV to the batteries, $E^{PV}_{Bat}(t)$, via

$$E^{PV}_{Bat}(t) = \min\left\{E^{Ba}(t), B\,C_{in} - E^D_{max}\right\} \tag{12}$$

The PV energy that can go into the battery, $E^{PV}_{Bat}(t)$, is then added to the initial battery energy, $E^B_I(t)$, to evaluate the final value for battery energy, $E^B(t)$. This is calculated considering the additional energy from the PV panels, $E^{PV}_{Bat}(t)$, and the maximum state of charge, S_{max}, of the battery via

$$E^B(t) = \min\left\{E^B_I(t) + E^{PV}_{Bat}(t), B\ S_{max}\right\} \tag{13}$$

Any fraction of $E^{Bal}(t)$ that it is not possible to store in the batteries due to either the maximum input permitted by the C-rate C_{in} or the maximum state of charge S_{max} being exceeded, is dumped.

Given that the batteries are being charged in hours when the diesel generator is running, they do not supply energy and the model records the energy supplied from the battery for the hour $E^B_{Sup}(t)$ as zero.

3.4.5. Calculating energy met by each source

The energy that meets demand can come from solar directly, $E^{PV}_{dir}(t)$, the battery storage (itself supplied by PV or diesel), $E^B_{Sup}(t)$, or from surplus diesel generation, $E^D_{sur}(t)$, during hours when the diesel generator is used to charge the batteries. $E^{PV}_{dir}(t)$ is calculated using the load profile $E^L(t)$ and the PV generation $E^{PV}(t)$, and is given by

$$E^{PV}_{dir}(t) = \min\left\{E^{PV}(t), E^L(t)\right\} \tag{14}$$

The surplus diesel available is calculated using the maximum diesel output, E^D_{max}, and the diesel energy already used to charge the battery, $E^D_{Bat}(t)$, via

$$E^D_{sur}(t) = \begin{cases} E^D_{max}(t) - E^D_{Bat}(t) & \text{if } E^D_{Bat}(t) > 0 \\ 0 & \text{otherwise} \end{cases} \tag{15}$$

The unmet energy $E^U(t)$ is the load energy $E^L(t)$ that remains when all available energy resources have been considered for each hour and is calculated after the simulation is complete. The total available energy is given by

$$E^{Tot}(t) = E^{PV}_{dir}(t) + E^B_{sup}(t) + E^D_{sur}(t) \tag{16}$$

and so the unmet energy profile $E^U(t)$ is given by

$$E^U(t) = \max\left\{E^L(t) - E^{Tot}(t), 0\right\} \tag{17}$$

and is reported as positive by convention.

3.4.6. Calculating diesel energy generated

To accurately estimate diesel fuel consumption, a profile of total diesel energy *generated* $E^D_{Gen}(t)$ is needed. This differs from the diesel energy *used* when the required energy from diesel would result in a load factor below the minimum load factor of the generator, Γ_{min}, and its resultant minimum diesel output E^D_{min}. E^D_{Gen} is therefore given by

$$E^D_{Gen}(t) = \begin{cases} \max\left\{D\ \Gamma_{min}, E^D_{Bat}(t) + E^D_{sur}(t)\right\} & \text{if } E^D_{Bat}(t) > 0 \\ 0 & \text{otherwise} \end{cases} \tag{18}$$

with the second case governing when the diesel generator is not in use. Once the simulation model has completed, the hourly profiles generated are used for the system analysis and appraisal.

3.5. System analysis and appraisal

3.5.1. System performance and impacts

The primary financial metric we use is the net present cost (NPC, in 2020 US dollars) and, in particular, the differences in NPC as a result of different in fuel costs in systems with different operational strategies. The NPC includes equipment, fuel, maintenance and other costs over the lifetime of the system and is subject to a discount rate to account for the time-varying value of money. Analogously, we calculate the cumulative lifetime GHG emissions (non-discounted) from all sources, measured in metric tonnes of carbon dioxide equivalent (tCO_{2eq}). Mathematical descriptions of these metrics, and the others we use, are given in the Supplementary Information B.2 with the cost and environmental impact input data shown in Tables 7 and 8 respectively.

Considering the amount of energy used by the system, we also calculate the per-unit impacts of electricity with the levelised cost of used electricity (LCUE, $/kWh). This measure is similar to the levelised cost of electricity (LCOE) but explicitly accounts only for electricity used by customers, rather than unused over-generation from PV [17,75,78]. We also calculate the emissions intensity of electricity, measured in gCO_{2eq}/kWh.

Battery degradation is assessed as the amount of energy that has been supplied by the battery as a proportion of the total that would be expected during its lifetime (dependent on the number of cycles at a given depth of discharge) [80–82]. As battery capacity degrades over time this measure, H, scales linearly from $H = 0\%$ when the battery is new to $H = 100\%$ when the battery has degraded to 80% of its original capacity, defined to be the end of its useful life.

Finally, we assess the overall performance of the diesel generator via the average probability that it is in use during a given hour of the day $P^G(t)$ and its average load factor Γ.

3.5.2. Identifying the optimum operational strategies

To compare a range of alternative strategies we altered two key criteria: the SOC set points at which the diesel generator is used, and the times at which these are in effect.

We modelled the same system over the same five-year period but with five depths of discharge: in the evening these ranged from a switch-on SOC of 50% to 70%, and in the daytime from 30% to 65%, each in 5% increments. For each set of SOC parameters we varied the times of the more restrictive evening period, with start times 17:00 to 21:00 and end times from 22:00 to 04:00 (presently 18:00–02:00 for the original strategy). Each combination of start and end times was modelled for each set of SOC parameters. Including the original SOC parameters (90% and 65%) this totalled 260 simulations.

From these simulations we selected an optimum "alternative strategy" which both reduces costs and avoids frequently reaching a low SOC, defined below 40% occurring more than once per week (14.3% of days), and never below 30%. This was informed by the operational advice provided by MeshPower Ltd.

3.5.3. Assessing the impacts of connecting business customers

Finally we assess the potential impacts of connecting 20, 50 or 100 refugee businesses and the increase in costs and GHGs, relative to those for the institutional loads only, under the alternative operating strategy, and also the original strategy for comparison. We then applied each of four potential tariff structures which are assumed to be paid by the businesses:

1. The current grid tariff in Rwanda of 89 RWF/kWh ($0.09/kWh) for consumers using 0–15 kWh/month,
2. A representative mini-grid tariff with a daily fee of 30 RWF ($0.03) plus usage tariffs of 400 RWF/kWh ($0.40/kWh) in the daytime and 600 RWF/kWh ($0.60/kWh) at night,
3. A usage-based tariff that will break even against the increase in diesel costs resulting from the business connections,
4. A daily fee-based tariff that will break even against the increase in diesel costs.

Tariffs 1 and 2 would offer the greatest parity with the host community, depending on whether they are connected to the national grid or a privately-operated mini-grid. Tariff 2 is similar to those used by the mini-grid operator MeshPower Ltd. in other rural communities and from which the demand profiles were constructed. Tariffs 3 and 4 are calculated to exactly offset the additional fuel costs incurred by the business users. These allow a simple consideration of the minimum tariff required for the operator to break even.

4. Results and discussion

4.1. Input data and load profiles

4.1.1. Institutional and business loads

The energy demand monitored from the existing system serving institutional loads is shown in Fig. 4 for the period from 1 January to 31 December 2020. The daily total energy demand is shown in Fig. 4(a), with both the monitored sum (translucent) and five-day moving average (solid). Two breaks in data collection occurred as a result of minor system faults during which time the system was nonoperational and so data was not recorded, resulting in 1.9% downtime. Total day-to-day demand is relatively consistent throughout, at 70.1 ± 10.0 kWh per day, but with a maximum daily demand of 96.9 kWh and a minimum of 46.7 kWh recorded during the one-year period.

Fig. 4(b) shows the hourly load profile of the monitored data as a series of box and whisker plots. The lower, central and upper bars of the boxes correspond to the first, second (median) and third quartiles of the data whilst the whiskers show the extent of values outside of 1.5 times the interquartile range, with values beyond these limits not shown for clarity. Monitored electricity demand typically falls within a range of 2–3 kW during the nighttime and 3–4 kW during the daytime, with much greater variability during the day.

Fig. 4(c) shows the mean synthesised daily load profile of the system (red solid line) which maintains the temporal profile of the monitored data with higher demand during the daytime. Fig. 4(c) shows the additional load of 20, 50 and 100 refugee business connections (black dotted, green dash-dotted and blue dashed lines respectively) in each scenario, using the breakdown of the types of businesses shown in Table 1. The average load profile for the connected businesses is concentrated during the daytime with demand amongst businesses peaking in the evening to prolong opening hours after sunset (around 18:00), after which it decreases overnight. The average of the peaks, above the baseline existing load, is around 350 W, 900 W and 1.8 kW for the low, medium and high connection scenarios. Electricity demand from business during the night is negligible. These load profiles are matched to the operating patterns of the businesses in the camp: while small shops might be open from early in the morning, other businesses with higher-power appliances such as hair salons typically operate around midday and the afternoon, whilst bars and restaurants stay open into the evening.

4.1.2. Overnight energy use

Altering the operational strategy of the diesel generator could affect the usage of the battery storage; this could have a pronounced effect overnight when the energy cannot be replenished by solar, potentially necessitating the use of the diesel generator once again and nullifying any fuel reduction benefits. In addition to the overall daily load profile, it is therefore important to assess whether typical energy use overnight could be satisfied via the storage alone, and to what extent the SOC limits may need to be altered to accommodate it.

Fig. 5 shows the cumulative overnight electricity demand remaining until sunrise (blue) and cumulative demand since sunrise (green) for each day of the monitored data. When solar generation is unavailable (typically 18:00 to 6:00), around 25–40 kWh of electricity (equivalent to around 30%–50% of the battery capacity) is required to meet the needs of the health centre and offices. A further 10–15 kWh (10%–20% of the battery capacity) would be required to power the system until 10:00 the following morning, for example, if solar generation were lower than expected owing to cloudy weather. For the highest-demand evenings an additional 10 kWh may be required to supply the system overnight.

The storage capacity is technically capable of supplying this amount of energy but not permitted to do so by the operating strategy. The current strategy used by the system initiates the usage of the diesel generator when the battery SOC falls below 90% between 18:00–02:00, or 65% thereafter, resulting in regular usage. As Fig. 5 suggests, if these SOC set points could be lowered then it may be possible to use battery energy alone to meet the overnight demands of the system. This necessitates an evaluation of the potential operating strategies and SOC set points to assess the optimal configuration.

4.2. Investigation of diesel operation strategies

4.2.1. The diesel-only system and original strategy

To establish a baseline against which to assess the hybrid system, and its possible operation strategies, we first evaluated the performance of the original diesel-only system under the synthesised institutional load profile. We found that using diesel generation only, over a five-year period, yielded a total diesel fuel cost of $56,200. Considering the logistical issues in transporting diesel fuel to remote locations such as refugee camps [67] this may underestimate the true cost. We found the system has a high environmental impact with an emissions intensity of 1182 gCO_{2eq}/kWh and GHG emissions of 168 tCO_{2eq} over the five-year period. Over a 15-year time horizon, the emissions intensity remains the same and the GHG emissions increases proportionally to 504 tCO_{2eq}, as no new capital expenditure is assumed.

We then modelled the performance and impacts of the hybrid system – following the installation of the solar and battery equipment – under its original strategy. During the "diesel hours" (18.00–02.00) the batteries were permitted to discharge just 10% of their available capacity, leaving 90% of the stored energy in the batteries but not available to be used. Below this threshold the diesel generator would be engaged to meet the loads and fully recharge the storage. During the remaining "quiet hours" the batteries were permitted to discharge a maximum of 35%, at which point the diesel charges them to 85% SOC. This strategy, designed to prevent excessive battery drainage overnight and to avoid potential damage from deep cycling, meant the generator would run almost exclusively during the diesel hours only. On average, this resulted in the diesel generator operating for 4.02 h between 18:00–02:00, and just 0.06 h during the quiet hours after 02:00. In the diesel-only system, the generator was required to run continuously to meet demand.

The hybrid system with the original operating strategy resulted in diesel costs of just $14,700 over five years, a reduction of $41,500 (74%) compared to the diesel-only system. The total GHG emissions from fuel use were reduced by the same percentage, as expected, to 44 tCO_{2eq}, and the emissions intensity fell by 45% to 651 gCO_{2eq}/kWh.

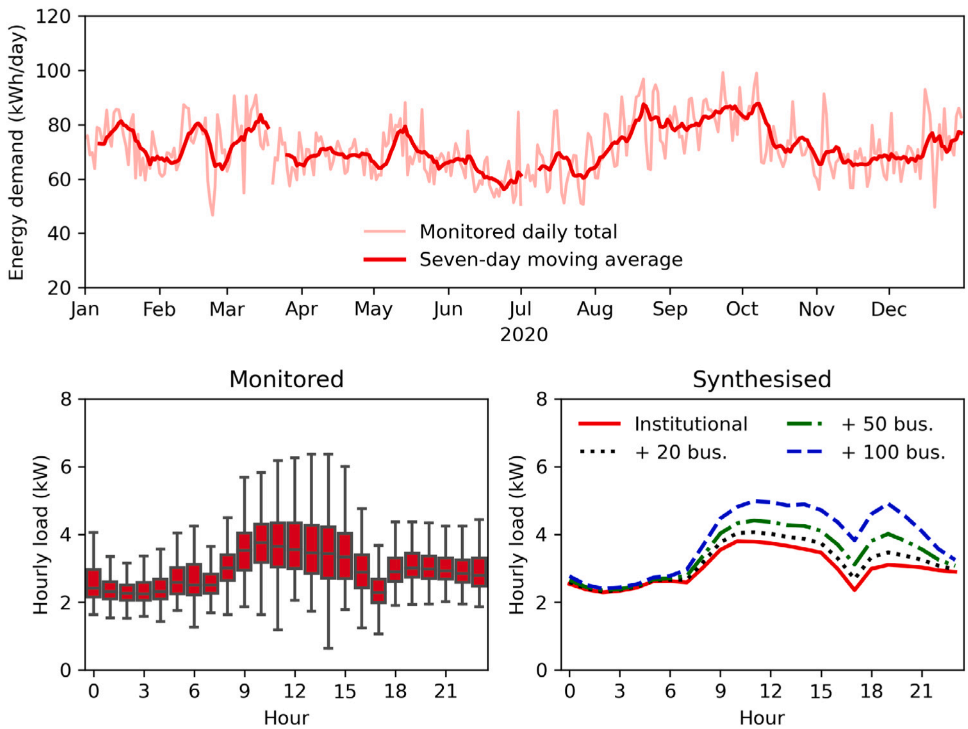

Fig. 4. Monitored energy demand of the Mahama camp system, showing (a) daily total energy demand and (b) hourly energy demand distributions, and (c) synthesised profiles of the institutional load and scenarios with 20, 50 and 100 business connections.

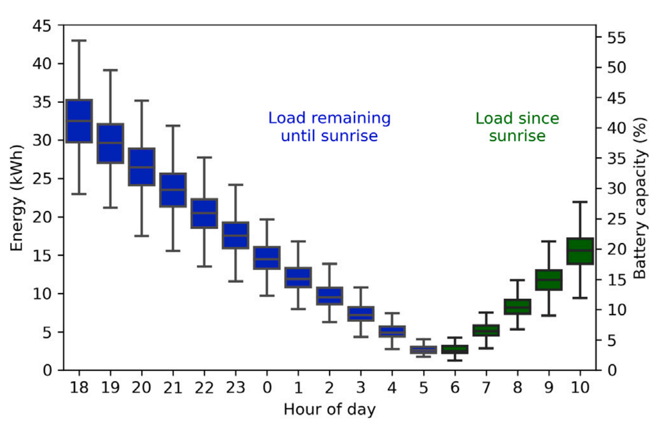

Fig. 5. Monitored night energy demand remaining until sunrise (blue) and energy demand since sunrise (green) in Mahama camp system. Energy demand is represented in kWh (left) and as a percentage of the battery capacity installed (right). Outliers are not shown for clarity.

The reduction is more modest than the reduction from emissions from diesel fuel due to the embedded emissions of the added renewable infrastructure (see Table 8). When considering a longer 15-year time period we find that the emissions intensity decreases substantially to 436 gCO_{2eq}/kWh.

This analysis focuses predominantly on fuel costs, and the potential of the system to reduce them, using solar and battery equipment which is already in place at Mahama Refugee Camp. This treats the initial investment in capital equipment as a sunk cost to directly focus on future savings, given that the equipment has already been installed. Calculating the LCUE for each system, however, offers an assessment of the overall costs of electricity inclusive of the costs of the grant-funded capital equipment, the prices of which are shown in Table 7, for a total equipment cost at the time of installation of $42,700. The diesel-only system was found to have an LCUE of $0.60/kWh over five years, while the LCUE of the hybrid system was $0.61/kWh. Considering instead a fifteen-year period the diesel LCUE is the same, as it is tied to the ongoing use of fuel, but the renewable equipment would generate more energy to pay off its initial investment, reducing the LCUE to $0.42/kWh.

No additional equipment is considered to be installed during the 15-year period, reflective of the lifetime many of the system assets, however, expected battery lifetimes are typically shorter. Whilst the battery does not degrade below its recommended minimum capacity for replacement in our simulation, our model of battery degradation does not take into account other factors affecting battery performance (see the Supplementary Information B.2). As opposed to our main focus on five-year time periods, the longer fifteen-year periods may require the replacement of batteries or other equipment which would induce additional costs and environmental impacts.

4.2.2. Analysing alternative operating strategies

Our simulations found that the original operating strategy was conservative in its use of the batteries. Only 15% of the battery lifetime was consumed after five years, but at the expense of using more diesel than might be necessary to meet demand, and so modifying the SOC set points and altering the time periods could offer opportunities to better to further reduce diesel consumption.

Fig. 6 shows the impacts of each modelled combination of SOC parameters (each categorised by colours) and timings over a five-year period. The horizontal axis displays the fuel cost savings relative to the original operating strategy and the vertical axis shows an estimate of the battery life consumed, as a percentage of the total expected life H. Strategies which allow greater depths of discharge result in higher usage, and subsequently degradation, of the batteries. Within each strategy the variations in timings offered fuel cost savings compared to the original strategy or, for some, increases.

For the original SOC parameters (green) the original timings perform relatively well: the majority of timing combinations offer lower fuel cost savings, although some would offer more. All of the timings have a modest impact on the battery, consuming between 14.6–18.5%

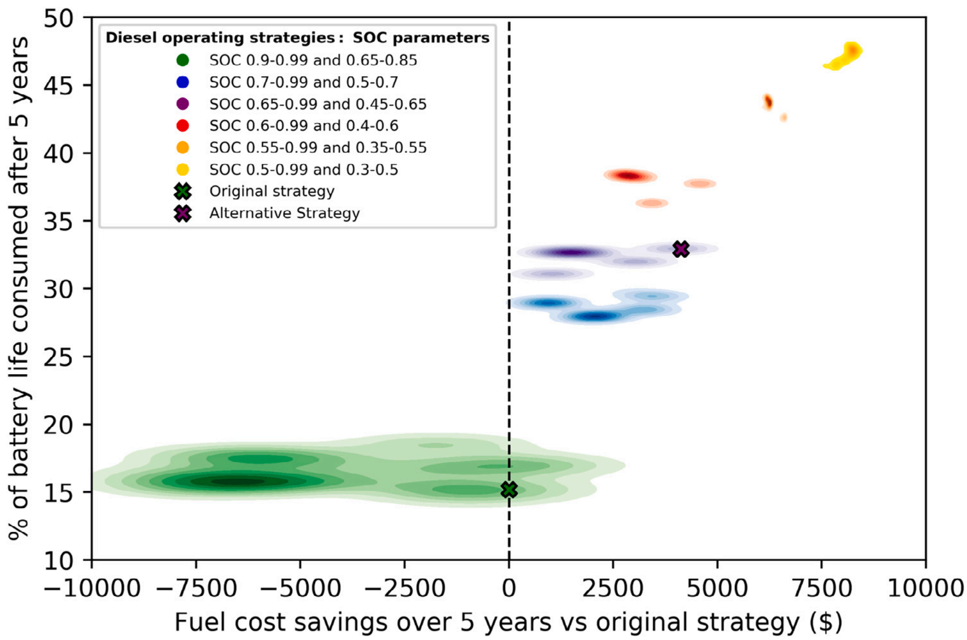

Fig. 6. The savings in fuel costs compared to the original operating strategy and percentage of battery lifetime consumed of different SOC parameters (each categorised by colour) and timings over a five-year period. SOC parameters are shown in the legend for "diesel hours" (left) and "quiet hours" (right). The darker shades of each colour represent a greater frequency of results at those values. Crosses highlight the impacts of the original strategy (green) and the selected alternative (purple). The original fuel cost savings (black dashed line) is $41,500 compared to the diesel-only system.

over five years, owing to the low depths of discharge. The most aggressive SOC parameters (yellow) offer the greatest utilisation of the battery storage and therefore have the lowest variations resultant from the timings of the diesel generator operation. These parameters use the highest amount of usable battery lifetime, up to H = 48%, but also offer the greatest fuel savings, up to $8600 – a 21% increase beyond the original fuel savings from the initial installation of solar and battery equipment.

Whilst the additional potential fuel savings are relatively high, at present prices none of the SOC combinations produce additional savings over five years that are large enough to fully cover the cost of replacing batteries. The price of batteries at the time of installation was $200 per kWh of nominal capacity, with a cumulative cost of $15,600 (equivalent to $9300, discounted at 10% over five years). For the cost of replacing all of the battery storage to match the maximum fuel savings ($8600) there would need to be a cost decrease of 1.6% per year. This rate is plausible but, in reality, the need to replace the batteries and its costs will depend on the actual technical performance and prevailing prices. Further, batteries are complex components to maintain and manage, with the possibility of deeper cycling or temperature leading to unpredictable impacts on lifetime and potentially necessitating earlier replacement. This may lead to additional issues and costs relating to the responsible end-of-life management of the batteries, for example to minimise its environmental impact, and for the sourcing of their replacement. System operators may therefore prefer to use a less extreme battery discharge strategy to balance fuel savings and battery lifetime.

4.2.3. Selecting an alternative strategy

An alternative strategy to improve on the current SOC and timings of the diesel generator operation should provide greater fuel cost savings whilst also respecting the additional constraint suggested by the mini-grid operator that the battery SOC should not drop below 40% on more than one day per week (14.3% of days) and never below 30%.

We identify the alternative strategy highlighted in Fig. 6 (purple cross) as meeting these conditions. This strategy allows the SOC to drop to 65% between 18:00–00:00 and 45% during the rest of the day. The SOC drops below 40% on just 6.4% of days. The SOC dropping to this level is an artefact of the resolution of the computational model, in which the diesel generator is engaged on an hourly basis which may occur after the lower threshold has been crossed, but similarly could replicate any delays in switching on the generator in the real system.

Over a five-year time horizon we find that this alternative strategy offers a further reduction in fuel costs of $4100 and 12.4 tCO_{2eq} of GHG emissions compared to the original strategy and consumes 33% of the battery lifetime; this equates to an economic cost of $2900, considering installed battery costs of $200/kWh and a 10% discount rate (see Table 7). The LCUE decreases marginally by 3% to $0.59/kWh, and the emissions intensity of electricity falls by 11% to 579 gCO_{2eq}/kWh. Over a 15-year time horizon the LCUE falls to $0.40/kWh and the emissions intensity to 340 gCO_{2eq}/kWh.

4.2.4. Impacts on battery usage

Fig. 7 compares the distribution of SOCs for the original (left) and alternative (right) operating strategies for each hour of the day, as well as the respective switch-on and switch-off SOCs. Between 00:00 and 06:00 the original strategy has a relatively narrow distribution of SOCs, which decrease until sunrise. This is a result of the batteries being fully charged in the evening before being depleted by overnight demands. The SOC distributions widen as the batteries charge in the morning, owing to variations in solar generation, and are almost always fully charged by 12:00. The batteries discharge to meet demand during the afternoon but the SOC is typically kept high by the solar generation, and by the diesel generator throughout the evening and night.

The alternative strategy, however, allows a greater depth of discharge and hence greater utilisation of the battery. Throughout all periods of the day there is a wider distribution of SOC and deeper discharges, particularly between 23:00–11:00, but despite this the battery is reliably charged to a high SOC by the solar generation by 15:00. The greater discharging during the evening occasionally causes the battery to reach the switch-on SOC and initiates the generator to run, resulting in three distinct peaks in the early morning depending on if or when this occurs. As required by the system operator, this strategy rarely has an SOC below 40%.

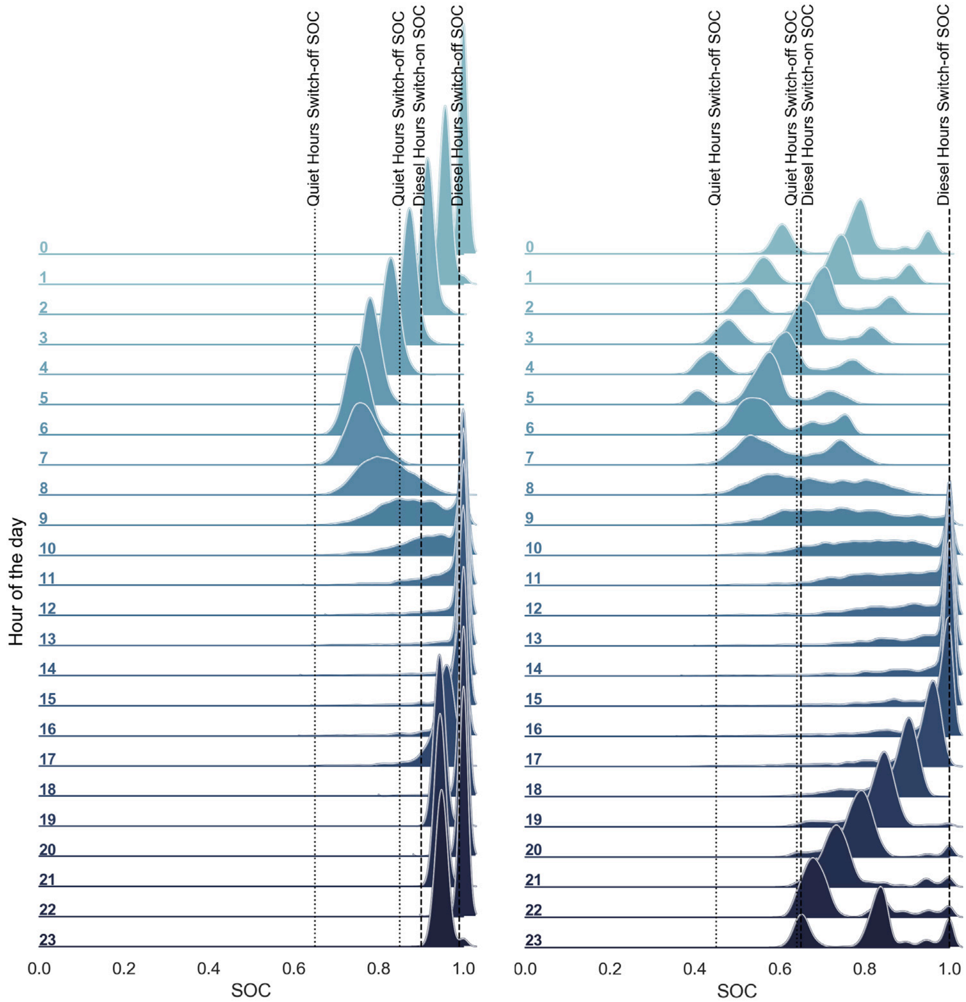

Fig. 7. The hourly state of charge of battery storage for the original strategy (left) and the alternative strategy (right). State of charge thresholds for both cases are represented as vertical lines (quiet hours thresholds in dotted line, diesel hours thresholds in dashed line).

4.2.5. Impacts on generator usage times and load factors

Fig. 8 shows the effects of the two strategies on the times of usage, given by P^G, and load factor, Γ, of the diesel generator. We find that under the alternative strategy the usage of the diesel generator decreases by 84% per night, to 1.06 h, but it is sometimes now used between 05:00–08:00 to top up the batteries if the SOC is low (cf. Fig. 7). Under this alternative strategy the diesel generator is not used at all on 16% of days, while under the original strategy it runs every night.

The load factor of the generator increases significantly by switching from the original strategy (Γ = 55%) to the alternative strategy (Γ = 97%). This could increase the fuel efficiency of the generator, which in our analysis constant rather than linked to the load factor, and could yield additional fuel savings. The original strategy also has more instances lower load factors near the minimum of 35%, which could cause operational issues and higher fuel expenditure per unit of electricity output. Meanwhile the fraction of electricity from renewable sources increases from 63% under the original strategy to 73% under the alternative.

In summary, we find that the alternative strategy is able to more flexibly utilise the available battery capacity without exceeding the constraints recommended by the system operator. It also offers reductions in fuel costs, LCUE, GHGs and emissions intensity as well as reducing the duration of generator usage overnight. Table 4 summarises the impacts of the diesel-only system, original strategy and alternative strategy.

Table 4
The fuel costs, fuel GHG emissions and technical performance of the diesel-only system, and the hybrid system under each of the original and alternative strategies over five years of operation.

Indicator	Diesel-only	Original	Alternative
Fuel cost ($)	56,200	14,700	10,600
Diesel GHG emissions (tCO_{2eq})	168.0	44.0	31.6
Battery life consumed (%)	N/A	15	33
Diesel generator load factor (%)	25	55	97
Diesel usage (hrs/evening)	8	4.02	1.06
Diesel usage (hrs/day)	24	4.08	1.66
Nights using generator (%)	100	100	84

4.3. Impact of connecting business customers

4.3.1. Impacts on system costs and GHG emissions

We modelled the integration of the additional loads from 20, 50 and 100 refugee businesses in the camp marketplace, shown in Fig. 4(c), and assessed their additional resultant cost and GHGs over the same five-year time frame under the alternative operating strategy.

We found that connecting 20, 50 and 100 businesses increases fuel costs by $266, $3170 and $6270 respectively, with corresponding GHG emissions increases of 0.9, 9.7 and 19 tCO_{2eq}. These cost increases are of comparable magnitude to the fuel cost saving availed by switching from the original strategy to the alternative strategy ($4100). Switching to the alternative strategy could therefore unlock fuel savings which

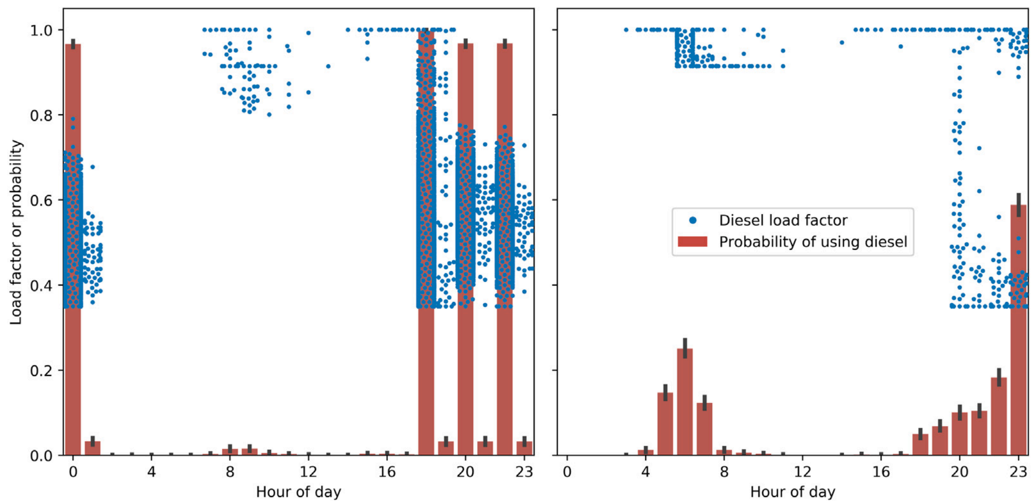

Fig. 8. The probability of use (bars) and load factor (points) of the diesel generator under the original strategy (left) and alternative strategy (right). Each point represents the load factor during one instance of the generator being used.

Table 5
The tariff structures for N = 20, 50 and 100 businesses and the percentage difference between the additional fuel costs and the revenue from customers (income minus fuel costs, divided by fuel costs). The mini-grid tariff is 400 RWF/kWh in the daytime, 600 RWF/kWh in the nighttime, plus a 30 RWF/kWh daily fee.

Tariff structure	Rate (RWF)			Difference (%)		
N	20	50	100	20	50	100
1. National grid (/kWh)	89	89	89	+108	−59	−60
2. Mini-grid	Variable			+1322	+182	+179
3. Usage break even (/kWh)	43	218	223	–	–	–
4. Daily break even (/day)	10	45	44	–	–	–

could be channelled, at least in part, to supporting business connections — minimising the overall financial impact but increasing opportunities for refugees.

By altering the timings of the alternative strategy (18:00–00:00), but keeping the SOC set points limits the same, we found that it is possible to reduce diesel costs and emissions. When connecting 50 businesses, diesel dispatch hours of 19:00–23:00 can achieve savings of around \$400 and 1.5 tCO_{2eq} over five years compared to the original timings for the alternative strategy; for 100 businesses, the same cost and emissions reductions are availed for dispatch times of 20:00–00:00. The technical performance recommendations of the operator remain unaffected. These results suggest that businesses can be connected to the system with moderate increases in diesel fuel usage, and that further tweaking the operating strategy can reduce the burden of additional connections.

4.3.2. Tariff structures for business customers

To offset these increases in fuel costs we apply the four options for tariffs. The structure of the tariffs, and the difference of their revenues against additional fuel costs resulting from powering the businesses, are shown in Table 5.

In general, connecting 20 businesses has a minimal impact on the system performance as this relatively modest increase in electricity demand can mostly be met by the excess solar generation during the day which previously was unused. This results in tariff scenarios for 20 businesses being relatively more favourable, owing to their lower costs. For 50 and 100 businesses, however, the increased energy demand requires greater usage of the diesel generator and hence the relative profitability of the same tariffs is lower.

Tariff 1, the national grid tariff, is able to recoup the additional fuel costs incurred in supplying 20 businesses but operates at a loss of around 60% for 50 or 100 businesses. For Tariff 2, informed by the mini-grid operator's experiences in rural areas of Rwanda, the system makes a profit on fuel costs for all customer levels, including a significant margin for 20 businesses. The inclusion of the daily fee is influential by increasing the profitability of providing power to these businesses whose electricity consumption (and hence revenue when charged per kWh) is low.

The revenue for the mini-grid tariff assumes that businesses pay the daily fee, and consume energy, 365 days per year, which would give \$3900, \$9300 and \$18,200 in revenue over five years for 20, 50 and 100 businesses respectively. This is in line with the current implementation of this tariff by the mini-grid operator in rural communities, but might be higher than reality. If we instead consider the mini-grid tariff with the same consumption but over 300 days per year the revenues for 20, 50, and 100 businesses are \$3800, \$8,900 and \$17,500 respectively. These maintain high profit margins, of 1322%, 182% and 179%, compared to the increase in fuel use; these are marginally lower than the original assumption but do not materially change the overall findings.

The rates of Tariffs 3 and 4 vary significantly between those for 20 and 100 businesses. This highlights the importance of estimating the demand for connections before setting the tariff, and in potential economies of scale. Both, by definition, achieve the goal of breaking even on additional fuel costs but Tariff 4 – designed around a daily fee, rather than consumption-based – may be favourable as it would allow more straightforward planning and financial forecasting for both the operator and businesses, but may incentivise higher consumption.

4.3.3. Comparative effects of each stage of the investigation

Fig. 9 summarises the overall financial impacts of each stage of the system investigation over the five-year period. Hybridising the system by first integrating solar and storage capacity yields the greatest single opportunity for savings (\$41,500) followed by further cost reductions (\$4100) resultant from changing the state of charge and timing parameters to those of the recommended strategy. To contextualise these savings, the total equipment cost at the time of installation (\$42,700) is approximately the same as the five-year fuel savings (\$41,500 to \$45,600). Depending on the real-life reductions in fuel use actualised over the system lifetime, and other factors such as diesel prices and operation and maintenance costs, this suggests the investment in equipment would have a payback time of around five years.

Integrating businesses, shown here for the case of 100 connections, increases fuel costs (\$6300) to satisfy their demand. These costs can be offset by introducing tariffs to earn revenue from the businesses: either

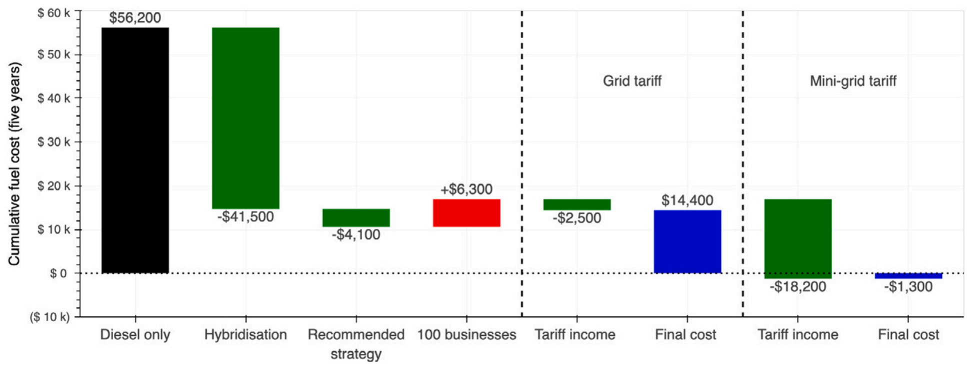

Fig. 9. The five-year cumulative fuel costs of the original diesel-only system (black), potential savings (green) and costs (red), and to alternatives for the final cost (blue) of the system with 100 business connections when using either the grid tariff (left) or the mini-grid tariff (right).

partially offset under the grid tariff ($2500), fully offset by either a usage-based or daily fee-based break even tariff, or more than offset ($18,200) if the mini-grid tariff were applied. All considered, the total fuel costs over five years of operation are completely abated as a result of the mini-grid tariff.

Our results suggest that the initial benefits of hybridising the system by introducing renewable technologies can be further extended by reassessing and optimising the operating strategy. They also suggest that businesses can be connected to the system in a manner that offsets the increased fuel costs or even provides a net income for the system operator. Matching the tariffs set by the subsidised national grid network would result in a loss ($3800 over five years) compared to the increased fuel costs, but these would be of a similar magnitude to the savings achievable through the optimisation of the diesel operational strategy ($4100). Permitting a mini-grid operator to replicate their tariffs from other systems would allow them to make a profit whilst potentially allowing both parity with the host community and a sustainable financial return for the operator.

5. Conclusions and recommendations

5.1. Designing hybrid systems to mitigate diesel usage

The aim of our work was to address four research questions, the first three of which focused on the use of electricity by institutional users in displacement situations, the performance and impacts of diesel and hybrid solar-diesel mini-grids to meet this demand, and the potential to optimise the operational strategies to minimise fuel costs.

Our results reaffirm the potential for solar power and battery storage to mitigate the usage of diesel generators in displacement settings and provide power for critical services [9,10,54,55]. Our analysis of data monitored from the electricity system in Mahama Refugee Camp, Rwanda, found that the average load was 70.1 ± 10.0 kWh/day in 2020 and that the diesel-only baseline system would have fuel costs of $56,200 and emit 168 tCO_{2eq} over a five-year period.

Using our novel introduction of a cycle-charging dispatch strategy into our modelling framework, we estimate that the introduction of 18.4 kW_p of solar capacity and 78 kWh of battery capacity by the mini-grid developer significantly reduces costs to just $14,700 and GHG emissions to 44 tCO_{2eq} over five years under the original conservative operating strategy for the generator. The 74% reduction in costs and GHGs is comparable to those found by previous studies [9,54,55].

Considering the institutional loads only, we identified that overnight energy use currently equates to around 30%–50% of the battery capacity and so altering the operational strategy of the generator would gain greater utilisation of the storage capacity to reduce fuel usage. Under the original strategy degradation was found to be just 15% over five years; other combinations of depths of discharge and generator usage times this could increase to up to 48%. None of these combinations offered fuel cost reductions which would cover the expense of replacing the batteries after five years at current prices: this would also require at least a 1.6% annual decrease in storage prices.

Using these results we suggest an alternative operating strategy which further reduces fuel costs by $4100 and GHGs by 12.4 tCO_{2eq} over five years. Under this strategy the storage SOC would drop below 40% on just 6.4% of days, meeting the technical performance requirements desired by the system operator. This achieves greater utilisation of the batteries, consuming 33% of the expected battery lifetime, and decreases generator usage by 84% per night whilst running at higher load factors.

These results demonstrate that large cost and GHG savings can be made via introducing solar and storage capacity into a diesel-based system, and further but more modest savings can be achieved via optimisation of the operational strategies. Even operators which must supply reliable power for critical services, as in our case study, could exploit greater usage of their storage capacity without exceeding their targets for minimum SOCs. Although fuel cost savings do not yet outweigh the cost of replacing the entire storage capacity, the required battery price decrease for breakeven (1.6% p.a.) is lower than anticipated cost reductions for lead–acid batteries (c. 3.5% p.a.) [83].

We recommend that system operators explore options for increasing the utilisation of the batteries via more liberal depths of discharge and combinations of generator timings, both of which can decrease the overall fuel consumption, and that investors (such as donors, financing organisations or the companies themselves) should consider battery replacement costs as part of a long-term deployment strategy to allow system operators to fully utilise the batteries.

5.2. Supporting business customers

Our final research question focused on the viability and potential profitability of connecting refugee businesses, whilst maintaining the overall reliability of the electricity system. We presented scenarios in which 20, 50 or 100 enterprises in the local marketplace were connected to the electricity system. We found that this additional energy use increased the fuel consumption and costs, but alternative operating strategies could reduce these below those of the original institutional-only system.

The tariff structures and the number of business customers affects the overall profitability of connecting refugee entrepreneurs. For 20 businesses, which mostly rely on excess generation from solar that would otherwise have been wasted, the required tariffs to offset fuel usage were low. For 50 or 100 businesses we found that matching the grid tariff (89 RWF/kWh) results in significant losses and would therefore need to be subsidised, perhaps from the institutional users, or avoided by profit-focused companies. Similarly, for 50 and 100 customers estimates for usage-based break even tariffs (218 and 223 RWF/kWh) are several times higher than the national grid tariff, which could result in perception barriers inhibiting adoption. Daily tariffs (10, 45 and 44 RWF/day for 20, 50 and 100 businesses) could however be received better by refugee businesses and be easier to administer and plan around for both customers and operators.

Not using a break even-based tariff avoids a potential perception of discriminatory pricing under which refugee businesses would be paying for the fuel usage only, whereas the institutional users would also be paying off the costs of the system. Charging the tariff used in the host community, however, could instead be perceived as favouring institutional users: refugee businesses would pay a commercial rate whilst institutional users have their electricity costs covered by Alight and UNHCR. The concerns for the latter could be assuaged by moving to a long-term power purchase agreement for the institutional users at a rate equal to or greater than the tariff for the businesses [8,9]. This would align the two payment structures and potentially offer simpler financial planning for the system operator and off-takers.

On balance, we recommend that systems operated by companies should be permitted to replicate the tariff structures used for their other sites for rural areas. In addition to parity with the host communities, we found that this tariff structure could provide a profit for the company. This could incentivise both greater numbers of connections and more sustainable business opportunities, satisfying the electricity demand for livelihoods opportunities found in this study and others [46,63]. This also aligns with the livelihoods objectives of humanitarian agencies and desirable for long-term private sector engagement [61,61].

Humanitarian organisations should therefore consider removing operational or organisation barriers to facilitate private sector involvement and support the provision of energy services in a similar manner to host communities. Mini-grid operators, meanwhile, should design systems with these potential enterprises in mind to account for their energy demand in sizing equipment capacities. These should be co-designed with the communities to maximise electricity utilisation and best meet the needs of their future customers [69,70].

5.3. Limitations of the study

Our use of a techno-economic modelling framework leads to endogenous methodological limitations relating primarily to its temporal resolution and inputs. The CLOVER model operates on an hourly resolution and therefore misses some of the dynamic behaviour that occurs at the sub-hourly level in the real-life system. Demand fluctuations are aggregated into hourly values and, for example, the modelled system is not required to respond to short, high power events which could affect the system and may cause greater battery degradation than modelled. Reformatting the input data and model processes to accommodate a higher temporal resolution could help to solve some of these issues, but would likely have relatively limited impact on the overall conclusions of this long-term study.

The model inputs, where data availability permitted, are accurate as a representation of the system installed at Mahama Camp. We use static prices that, for example, do not account for changes in fuel price and which would proportionately affect the system fuel costs. Care should be taken when comparing the results of this study to other locations with significantly lower fuel prices.

The model simplifies the treatment of fuel consumption by the diesel generator when compared to the installed system. Although fuel consumption per kWh supplied is typically lower at higher capacity factors [84], similarly to other studies [10,85] our modelling framework assumes a constant rate of fuel consumption. The original and alternative strategies in our analysis have average capacity factors of 55% and 97% respectively and we can therefore reasonably assume the fuel savings in our alternative strategy would be higher, and therefore more favourable, than we report. Future work could incorporate variable fuel consumption to assess this.

To evaluate businesses connections it was necessary to use proxy data based on customers elsewhere in the country. The magnitude of daily demand was based on the aspirations of humanitarian agencies and the Government of Rwanda but the actual daily demand is likely vary significantly between days and types of businesses with different needs, which could affect system utilisation [70]. The number of business connections could vary dependent on the local demand, tariff structures, ability and willingness to pay, and the supporting environment. Our investigation therefore offers different numbers of connections and types of tariff structures as a range of possible outcomes for the future situation.

Finally, aside from the inherent specificities of electricity use in Mahama Camp, Rwanda has both relatively well-defined electricity access targets and a progressive environment for displaced people. As such, Rwanda offers a high potential for the implementation of such electricity systems which may not be representative of other countries. The technological and economic benefits of hybrid mini-grids would remain applicable in countries with similar prices and solar resource, for example, but the enabling environment is a critical component for implementation and should be considered when comparing this work to other countries.

5.4. Recommendations for humanitarian organisations, policymakers and the private sector

As the number of renewable and hybrid electricity systems deployed in displacement settings continues to grow it will be important to ensure that they are cost effective, well-designed and provide reliable electricity to both humanitarian organisations and displaced people.

Governments, NGOs and humanitarian agencies should consider the use of renewable energy infrastructure in camps as a critical component of their sustainability strategies. The large GHG emissions reductions possible through the use of such systems, shown by this work and others [9,10,54,55], highlights their compatibility with national and organisational sustainability targets. Extending electricity connections to local businesses, meanwhile, is in direct alignment with the aims of SDG 7 [47] and humanitarian objectives [61,62].

Humanitarian organisations and partners responsible for infrastructure and electricity provision in camps, for example UNHCR and Alight in our case study, should integrate solar and battery storage into existing diesel systems. Engaging with the private sector can exploit its ability to raise initial capital and long-term financing, as well as its specialist knowledge in deploying and operating such systems — including amending operating strategies to maximise fuel savings. This can help overcome the one-year funding cycles and limited in-house expertise of humanitarian organisations and NGOs [8] by, as in this case, partnering with a local electricity service company. Contractual frameworks could help initial system deployment [56,57] whilst power purchase agreements or leasing mechanisms could support long-term operation [8,9].

Private sector mini-grid companies should explore opportunities for providing electricity services in displacement settings. Institutional and community facilities can provide stable and reliable anchor customers whilst extending electricity services to local businesses can be a profitable endeavour, as replicating tariffs used at other sites can provide a profitable return even for modest numbers of connections. After initial deployment, companies should use their expertise to reassess the operational strategies to maximise fuel savings and consider the trade-offs in battery usage, particularly if storage costs decrease.

Academic and research organisations should identify the most favourable conditions and implementation strategies for sustainable energy systems in displacement settings. More research is required into their replicability in other locations and contexts, and the generalisability of the proposed implementation and operational strategies. Studies which monitor the technological performance, energy usage, and payments of customers over several years should be supported by social and community-focused research which would provide great insight into the viability and sustainability of such systems in the long term.

Achieving SDG 7 in displacement settings will require coordinated action and rely on humanitarian agencies, NGOs, governments, research organisations and private companies to work together and exploit their expertise, experience and capabilities. Coordinated multi-stakeholder action will be necessary to replicate successful examples of renewable electricity projects and scale up their implementation to achieve sustainable, affordable, reliable and modern energy for all.

CRediT authorship contribution statement

Hamish Beath: Conceptualization, Methodology, Software, Investigation, Writing – original draft, Writing – review & editing, Visualization, Funding acquisition. **Javier Baranda Alonso:** Methodology, Software, Investigation, Data curation, Writing – original draft, Visualization. **Richard Mori:** Conceptualization, Resources, Data curation, Project administration, Funding acquisition. **Ajay Gambhir:** Writing – review & editing, Supervision. **Jenny Nelson:** Writing – review & editing, Supervision, Project administration, Funding acquisition. **Philip Sandwell:** Conceptualization, Methodology, Software, Investigation, Writing – original draft, Writing – review & editing, Visualization, Supervision, Project administration, Funding acquisition.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

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Appendix A

See Tables 6–8.

Table 6
Model inputs used for the system technical specification.

Item	Value	Unit	Source
PV capacity	18.4	kW_p	
PV tilt	15	Degrees above horizontal	
PV azimuth	0	Degrees from North	
PV lifetime	20	Years	
Diesel capacity	13.0	kW	
Diesel fuel consumption	0.31	L/kW/h	[85,86]
Diesel minimum capacity factor	35	%	[87]
Battery capacity	78.0	kWh	
Battery maximum SOC	Varies	%	[88]
Battery minimum SOC	Varies	%	[88]
Battery leakage	0.13	%/h	[88]
Battery round-trip efficiency	92	%	
Battery cycle lifetime	2000	cycles	[88]
Battery lifetime capacity loss	20	%	[88]
Battery C rate discharging	0.2	/h	[88]
Battery C rate charging	0.13	/h	[88]
Inverter lifetime	10	Years	
Transmission efficiency (DC)	96	%	[89]
Transmission efficiency (AC)	92	%	[89]
DC to AC conversion efficiency	97	%	[90]
DC to DC conversion efficiency	95	%	[89]
AC to DC conversion efficiency	90	%	[91]
AC to AC conversion efficiency	98	%	[90]

Table 7
Model inputs used for the economic assessment.

Item	Value	Unit	Source
Discount rate	10	%	
PV cost	400	$/kW_p	[92]
Storage cost	200	$/kWh	[92]
Diesel fuel cost	1.13	$/L	[92]
Diesel O&M	43	$/kW p.a.	[93]
BOS cost	100	$/kW.	[92]
PV inverter cost	163	$/kW	[92]
Battery inverter Cost	10000	$	[92]
General O&M	2400	$ p.a.	[92]

Appendix B. Supplementary information

B.1. Constructing load profiles

B.1.1. Institutional profile

The total load monitored in the hour t, $L^M(t)$, is taken to be the sum of the energy supplied to the consumers by each source i, $S^i(t)$, for $i \in$ {PV, Diesel, Battery}, such that

$$L^M(t) = \sum_i S^i(t) \tag{B.1}$$

The total load $L^M(t)$ is then reformatted into a matrix L^M_{dh} of dimensions $d \times 24$ for each day $d \in \mathbb{Z}^+$ recorded over a total of D days, and at the hour $h \in \{0, 1, 2, \ldots, 23\}$. The mean μ^M_h and standard deviation σ^M_h of the monitored data in each hour h are given by respectively by the usual formulae

$$\mu_h = \frac{1}{D}\sum_d L^M_{dh} \tag{B.2}$$

and

$$\sigma^M_h = \sqrt{\frac{\sum_d \left(L^M_{dh} - \mu^M_h\right)^2}{D}} \tag{B.3}$$

These are used as inputs to generate a synthesised load profile, $L^S(t)$, which can be taken as an input to the modelling process. A new matrix L^M_{lh} of dimensions $l \times 24$, for each day $l \in \mathbb{Z}^+$ in the time frame considered, in our case $l \in \{1, 2, \ldots, 1825\}$ for five years, is constructed. Each element of L^S_{lh} is set to the value of R_{lh} drawn at random from the normal distribution $\mathcal{N}(\mu^M_h, \sigma^{M2}_h)$, for its corresponding hour h, and subject to the condition

$$L^S_{lh} = \begin{cases} R_{lh} & \text{for } R_{lh} \geq 0 \\ 0 & \text{for } R_{lh} < 0 \end{cases} \tag{B.4}$$

This condition avoids unphysical negative electricity demands. As this process does not allow values less than zero, as $\mathcal{N}(\mu_h, \sigma^2_h)$ does, this results in the mean of the synthesised data, μ^S_h, being greater than the monitored data, i.e. $\mu^S_h \geq \mu_h$ by definition. In practice the difference between the two values is negligibly small and $\mathcal{N}(\mu^M_h, \sigma^{M2}_h) \sim \mathcal{N}(\mu^S_h, \sigma^{S2}_h)$ as desired by this framework. The synthesised matrix L^S_{lh} is then converted into a load profile $L^S(t)$ by sequentially ordering its elements by day and hour.

B.1.2. Business load profiles

We assumed that each business of type $b \in B$, where B is the set of all business types in the camp (for example shops, restaurants, hair salons, phone chargers and others), has an associated daily load profile L^b_h. This is assumed to be seasonally invariant and has an hourly mean and standard deviation of μ^b_h and σ^b_h. Using a process similar to that

Table 8
Model inputs used for the environmental assessment.

Item	Value	Unit	Source	Comments
PV	1498	$kgCO_{2eq}$/kWp	[94]	Manufacturing in China
Storage	233	$kgCO_{2eq}$/kWh	[95]	
Diesel generator	0	$kgCO_{2eq}$/kW		Already installed
Diesel fuel	2.68	$kgCO_{2eq}$/L	[78]	
Balance of systems	134	$kgCO_{2eq}$/kW	[96]	
Inverters	124	$kgCO_{2eq}$/kW	[94]	Manufacturing in China

described in the previous section, each individual business is assigned a randomly allocated load profile $L_n^b(t)$ for each of n_b businesses of type b, which sum to the total number in the marketplace N.

The number $n_b \in \mathbb{Z}^+$ of each business type b was informed by a survey of 142 businesses in the Mahama Camp marketplace conducted in January 2019. The proportion of businesses of each type in the survey is converted into an integer n_b and is constant throughout the considered time frame, conforming to

$$N = \sum_{b \in B} n_b \tag{B.5}$$

The load profile of an individual business is considered independently with each being assigned an index $n \in \{1, 2, \ldots, n_b\}$ and its associated generic load profile $L_n^b(t)$. The cumulative load profile of all N businesses in the marketplace is therefore given by

$$L_N^B(t) = \sum_{b \in B} \left(\sum_{n \in n_b} L_n^b(t) \right) \tag{B.6}$$

and therefore the total load profile, considering both the institutional loads and business customers, is given by

$$L_N^T(t) = L^S(t) + L_N^B(t) \tag{B.7}$$

B.1.3. Input data for business loads

Monitored electricity usage data for refugee businesses was not available and so we use data measured from 19 business customers connected to a MeshPower system in the village of Gitaraga, Rwanda which are similar to those in Mahama Camp and other displacement situations. Electricity usage data from the Gitaraga site was taken from a previous study which made these data available [74].

From these data, we categorised businesses according to type (bars, shops, etc.) and the calculated the mean and standard deviation of electricity use of each business type for each hour of the day. We then scaled the daily usage for each business type to the target value of 200 Wh per day. These new load profiles were used for L_h^b as described above. The hourly load profiles for each business type and the cumulative load profile of each scenario are shown in Fig. B.1(a) and (b) respectively. We have made the load profiles for individual businesses and each scenario used in this work publicly available [97].

Most business types demonstrate higher demand throughout the afternoon and evening periods, with the exception of the tailor and workshop which have peaks of demand in the morning. When considered cumulatively, the total load demand is high throughout the morning and afternoon with a peak in the evening at 19:00. The addition of the three business scenarios to those of the institutional loads, to give the total system load, is shown in Fig. 4.

In this work we use the same composition of business types in each scenario and so the cumulative load scales linearly with the number of connections. Changing the relative proportions of businesses would affect the timings and magnitude of demand throughout the day which would have subsequent effects on the system performance and impacts. As the modelled business demand is relatively high in the evening, if more demand were instead concentrated in the daytime then this might be able to be met through solar power and therefore potentially reduce battery and/or fuel usage.

B.2. Calculating system performance and impacts

The total lifetime NPC, C^T, is defined by

$$C^T = \sum_{n}^{N} \left(\sum_{j} \frac{C_n^j}{(1+r)^n} \right) \tag{B.8}$$

for the cost C_n^j of type j (for example equipment, fuel, maintenance), occurring in year n of the considered lifetime of N years, and subject to the discount rate r. Similarly, the primary environmental metric used in our analysis is the total GHG emissions G^T given by the sum of the emissions from each component j in year n, that is

$$G^T = \sum_{n}^{N} \left(\sum_{j} G_n^j \right) \tag{B.9}$$

In our analysis both C^T and G^T are governed almost entirely by diesel fuel and operation and maintenance requirements, as the equipment costs for the generation and storage capacity have already been covered before the considered lifetime begins, which offers a fair analysis given the consistent comparison to the same reference system. The levelised cost of used electricity (LCUE, measured in \$/kWh), L, is given by dividing the total costs incurred by the system by the total discounted energy supplied E_{Disc}^T,

$$L = \frac{C^T}{E_{Disc}^T} \tag{B.10}$$

where the total discounted energy over the considered time period is given by

$$E_{Disc}^T = \sum_{n}^{N} \frac{E_n}{(1+r)^n} \tag{B.11}$$

in which E_n is the amount of energy used by the users in the year n, and the equation accounts for the discount rate by convention. The LCUE explicitly accounts for only energy used by the system and does not, for example, consider the dumped energy from excess generation in its consideration as this was not usefully consumed by the users. Analogously the emissions intensity of the system g, measured in gCO_{2eq}/kWh, is given by

$$g = \frac{G^T}{\sum_n E_n} \tag{B.12}$$

and does not consider discounted values, by convention.

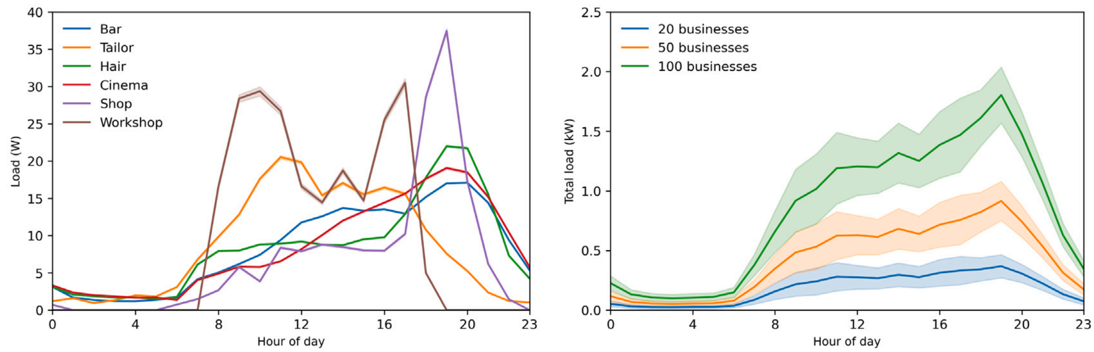
The lifetime usage of the battery storage is assessed via the proportion of the total expected battery usage over its lifetime, E_T^{Bat}, that has been consumed by time t [80–82]. This measure, $H(t)$, assumes a linear degradation in capacity and is taken to be the cumulative energy supplied by the battery, $E_{Cum}^{Bat}(t)$, divided by E_T^{Bat}. E_T^{Bat}, and therefore $H(t)$, will be dependent on the battery usage strategy k which will allow for an expected number of charging and discharging cycles ξ_k at a maximum depth of discharge δ_k. This gives us

$$H_k(t) = \frac{E_{Cum}^{Bat}(t)}{B\ \xi_k \delta_k} \equiv \frac{E_{Cum}^{Bat}(t)}{E_{T,k}^{Bat}} \tag{B.13}$$

for an installed battery storage capacity of B kWh. $H(t)$ is expressed as a percentage of the total expected lifetime cumulative energy throughput that the battery storage has experienced. For example, for a battery which is judged to have reached the end of its life ($H = 100\%$) once its ability to store energy degrades to 80% of its original capacity, it is defined to have $H = 25\%$ when operating at 95% of its original storage capacity, $H = 50\%$ at 90% of its original capacity, and so on.

The usage and technical performance of the diesel generator are assessed via two metrics. The first, $P^G(t)$, is the probability that the generator is in use in during a given hour of the day t and is given by

$$P^G(t) = \frac{1}{T} \sum_{t}^{T} G^{on}(t) \tag{B.14}$$



(a) Individual load profiles.

(b) Cumulative load profiles.

Fig. B.1. The load profiles of (a) individual businesses of each type and (b) the scenarios of 20, 50 and 100 businesses cumulatively.

where

$$G^{on}(t) = \begin{cases} 1 & \text{for } E^D_{Gen}(t) > 0 \\ 0 & \text{otherwise} \end{cases} \tag{B.15}$$

Electricity supplied by the generator, $E^D_{Gen}(t)$, of any amount triggers $G^{\text{on}}_{dh} = 1$ for that hour and day. This therefore represents the probability that the generator is in use at any point during the hour, rather than the total usage time, as the latter is would require a sub-hourly resolution which is not possible in this modelling framework.

The load factor of the generator, $\Gamma(t)$, is the proportion of the maximum available power output of the generator, D, being used in that hour. It has a lower bound set by the designated minimum operating load factor for the generator, Γ_{min} described in Section 3.4.6, and is given by

$$\Gamma(t) = \frac{1}{D} E^D_{Gen}(t) \tag{B.16}$$

which results in $\Gamma(t) \in [\Gamma_{\text{min}}, 1]$.

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