Assessing the potential for photovoltaic technology to mitigate greenhouse gas emissions:

Life cycle analysis and energy systems modelling for electricity access in rural India

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Declaration

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Philip Richard Sandwell

21 December 2017

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Abstract

Solar photovoltaic (PV) technologies are becoming increasingly accessible as a source of reliable, sustainable and affordable electricity. Cost decreases and manufacturing improvements have meant that energy generated from PV is a viable alternative to fossil fuel generation, whilst also offering a significant potential to offset the greenhouse gas (GHG) emissions from incumbent energy sources. In this work I investigate the potential of PV technologies to mitigate GHGs with a focus on the application of PV towards rural electrification in India. I present the costs and emissions associated with the deployment of mature and emerging PV technologies in minigrid electricity systems and compare their impacts with those of incumbent diesel generation and the extension of the grid network, identifying the scenarios which favour PV minigrids. I also present the life cycle analysis of a new design of concentrating PV module, and its opportunities to mitigate GHGs in various locations around the world, finding that it can offer emissions intensities lower than other renewable technologies. I analyse the current levels of energy access of communities in rural Uttar Pradesh, India and find that there is a significant opportunity to mitigate GHG emissions from kerosene usage. I also present an estimation of the potential future energy demand that would provide them with electricity access. I describe a new framework for energy systems modelling, CLOVER, that simulates and optimises minigrid systems which can increase in generation capacity in response to growing levels of electricity demand. I apply this framework to minigrid systems in Uttar Pradesh and find that PV systems which offer opportunities for economic development can provide electricity at both a lower cost and lower GHG emissions than either diesel generation or hybrid systems. Finally, I identify the greatest opportunities for PV minigrid system to provide affordable electricity and mitigate GHGs.

List of abbreviations

a-Si	Amorphous silicon
AC	Alternating current
BOS	Balance of systems
c-Si	Crystalline silicon
CDF	Cumulative distribution function
CdTe	Cadmium telluride
CED	Cumulative energy demand
CFL	Compact fluorescent lamp
CIGS	Copper indium gallium sellenide
CLOVER	Continuous Lifetime Optimisation of Variable Energy Resources
CO_{2eq}	Carbon dioxide equivalent
CBPT	Carbon payback time
CPV	Concentrating photovoltaics
DC	Direct current
DHI	Diffuse horizontal irradiance
DNI	Direct normal irradiance
EPBT	Energy payback time
gCO_{2eq}	Grammes of carbon dioxide equivalent
GHG	Greenhouse gas
GHI	Global horizontal irradiance
GW	Gigawatt
HCPV	High-concentrating photovoltaics
HOMER	Hybrid Optimization of Multiple Energy Resources
IEA	International Energy Agency
INR	Indian rupee
$kgCO_{2eq}$	Kilogrammes of carbon dioxide equivalent
kW	Kilowatt
kWh	Kilowatt hour
kW_p	Kilowatt-peak
LCA	Life cycle analysis
LCGE	Levelised cost of generated electricity
LCOE	Levelised cost of electricity
LCUE	Levelised cost of used electricity

LED	Light emitting diode
Li-ion	Lithium ion
MAC	Marginal abatement cost
MJ_{EPE}	Megajoules of equivalent primary energy
mono-Si	Monocrystalline silicon
multi-Si	Multicrystalline silicon
MW	Megawatt
NOCT	Nominal operating cell temperature
NPV	Net present value
NREL	National Renewable Energy Laboratory
O&M	Operations and maintenance
OPV	Organic photovoltaics
PCB	Printed circuit board
PV	Photovoltaics
SE4All	Sustainable Energy for All
SHS	Solar home system
SME	Small or medium enterprise
SOE	Secondary optical element
tCO_{2eq}	Tonnes of carbon dioxide equivalent
USD	United States dollar
W	Watt
Wh	Watt hour
W_p	Watt-peak

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Chapter 1

Introduction

1.1 Introduction

The technological improvements, cost reductions and manufacturing innovations that solar photovoltaics (PV) have experienced have made the technology more accessible than ever. With a cumulative installed capacity of more than 300 GW worldwide, and with annual deployments in many countries growing every year, energy generated from PV is becoming increasingly important in meeting global energy needs [1]. Research and deployment of PV technologies has been motivated by the goal of mitigating global climate change as electricity produced from renewable sources can offset the emission of greenhouse gases (GHGs) from fossil fuel generation. Furthermore, research continues into new and emerging PV technologies as well as into the application of mature technology to meet new challenges: PV is expected to make significant contributions to providing 1.1 billion people around the world with access to sustainable, reliable and affordable electricity for the first time by 2030 [2].

In this work I will assess the potential of PV technologies to mitigate GHG emissions by investigating the application of mature and emerging technologies and, in particular, the potential of PV to meet the challenge of providing electricity to communities in rural regions of India. I will consider the use of two kinds of emerging PV technologies, organic photovoltaics and concentrating photovoltaics, and will then focus on the potential of mature crystalline silicon technology to supply minigrid systems for energy access in Uttar Pradesh, India. In addition to analysing the costs and performance of PV systems to evaluate their technical and economic viability, I will also use life cycle assessment (LCA) to quantify both the GHGs of the systems themselves and the emissions that they can mitigate in comparison to other electricity sources. Using energy systems modelling I will simulate and optimise minigrid systems for electricity access in rural India and identify the conditions under which PV can provide the greatest benefits. This will allow me to assess the potential of PV technologies to mitigate greenhouse gas emissions in the scenarios I consider.

In this chapter I will introduce the context of this work and, by reviewing the relevant literature, identify the key research gaps that are addressed in the subsequent chapters. In section 1.2 I will introduce solar PV and its recent history of technological improvements, cost decreases and potential to mitigate GHG emissions. In section 1.3 I will describe the key issues in the field of electricity access, how it can be defined, methods of providing it, how this can be done sustainably, and finally the electricity access situation in India. In section 1.4 I present the ways in which minigrid systems are simulated, optimised and assessed in the literature and the benefits and shortcomings of each. Finally, in section 1.5, I will describe the aims of this work and the structure that it will use to achieve them.

1.2 Solar photovoltaics

1.2.1 Introduction

Overview

Solar photovoltaic (PV) energy has been experiencing phenomenal growth. In 2016 more than 75 GW of PV generation capacity was installed, an increase of 50% compared to the annual figure for 2015, which itself built upon a 25% increase from the year before [1]. The relative simplicity of PV systems means that, after installation, only a relatively small amount of upkeep is required to maintain a reliable supply of electricity whenever the sun is shining. Furthermore, the modularity of the technology allows PV to be installed at any scale from the smallest solar lamps to the largest utility-scale solar farms. Continuing efficiency improvements, driven by fundamental scientific research [3, 4] and manufacturing innovations, have delivered consistent decreases in cost [5] and mean that energy generated from PV technology is more accessible then ever before.

All PV technologies rely on the same basic principles to convert light into electricity. When light is incident on the semiconductor material of a solar cell a photon can either pass

through the material, be reflected at the surface, or be absorbed: for absorption to occur, the photon must have an energy greater than that of the band gap. If the photon is absorbed it transmits its energy to a negatively-charged electron in the semiconductor structure and excites it into the conduction band, leaving a corresponding positively-charged hole in the valence band, which then travels through the material and can be collected at electrodes. These electrodes can be connected to external loads which use the current provided by the flow of electrons from the solar cell for electrical power; after passing through the circuit, the electrons then recombine with the holes. The choice of semiconductor material will affect the energy of the band gap, the amount of light that is absorbed and many other factors, including the overall efficiency of the solar cell.

The electricity supplied by PV systems is ultimately dependent on the availability of sunlight and, as a result, is inherently intermittent. For systems connected to the national grid network this may not be an issue for the system itself as any electricity that is generated can be exported to the grid. The national transmission network, however, may be required to react in response to decreasing or increasing PV energy production by increasing or curtailing power production from other sources. Off-grid systems, meanwhile, are required to invest in energy storage systems such as batteries if they wish to provide power during periods of darkness or reduced cloud cover.

Composition of PV systems

PV systems are composed of many different components. PV cells, which convert light into electricity, are housed in modules which themselves are mounted onto racking structures to fix them in place during deployment. Wires and cabling transmit the power from the modules and out of the PV system, possibly via an inverter to change the generated direct current (DC) electricity into alternating current (AC) that is used by the national grid network.

The system components other than the PV module are collectively known as the balance of system (BOS) and have also experienced cost decreases in recent years, although not as significant as for modules. In 2007 BOS costs accounted for around one quarter of the cost of a grid-connected domestic rooftop system in Germany but by 2016 this proportion had increased to more than half; although the total system decreased by about 70% in the same period, the rapid decline of module prices has so far been unmatched by other components [5]. Roof-mounted household systems typically have proportionately higher BOS costs but completely off-grid systems, such as minigrids, also rely on other components such battery storage, charge controllers, power converters and a local distribution network. This can increase their cost significantly and, in doing so, increase the cost of electricity and the GHG emissions that are released during the production of the system components.

PV and many other renewable technologies do not require fuel to generate electricity. This means that the investment required to deploy and utilise PV systems are predominantly initial capital expenditures, rather than recurring operating expenditures as is the case for fossil fuel power plants. The maintenance required for the upkeep of a PV system is relatively minor and although there are some recurring costs, such as replacing expired BOS components, these are fall smaller than the initial capital investment. Fossil fuel generation can typically match the output of the plant to the expected power demand, potentially reducing their fuel usage and therefore allowing them to reduce costs. PV systems cannot do this and are instead designed to maximise their cumulative lifetime energy generation, first to repay their initial investment and then to produce profitable power to secure a return on investment.

Comparing PV systems to other electricity sources on the basis of their initial investment expenditures would be unrepresentative and, whilst this can play a role in selecting the most suitable generation source, it is more common to use the levelised cost of electricity (LCOE) to assess the suitability of a system. This takes into account all of the lifetime expenditures of the electricity system and allows for a fairer comparison. The recent cost reductions and

efficiency improvements that PV systems have experienced have reduced its LCOE and increased its competitiveness; this has resulted in growing numbers of PV systems being deployed around the world each year. In this section I will outline some of the advantages of different PV technologies, how PV can be used for GHG mitigation, and the gaps in the literature which are yet to be explored.

1.2.2 Advantages of solar photovoltaics

Efficiency increases

Dedicated research into fundamental science has led to consistent efficiency improvements across many kinds of PV technologies. The National Renewable Energy Laboratory (NREL) maintains a chart of the progression of research cell efficiencies from 1976 to the present, reproduced in fig. 1.1, which illustrates these improvements. Established technologies such as crystalline silicon (c-Si) cells have been produced with efficiencies of more than 25% under standard test conditions, and thin-film technologies such as cadmium telluride (CdTe) and copper indium gallium sellenide (CIGS) have achieved more than 22%. Emerging technologies such as organic photovoltaics (OPV) have demonstrated efficiencies greater than 11% and multijunction cells, such as those used in concentrator photovoltaic (CPV) systems, have recently reached 46% efficiency under concentration.

The latest edition of the of six-monthly listings of the highest-performing cells by Green et al. [4], recurring since 1993, summarises the state-of-the-art in PV technologies and provides an additional insight into the performance of modules. The best-performing c-Si modules, for example, lag behind their research cell equivalents but achieve an efficiency of $24.4 \pm 0.4\%$. Whilst commercial manufacture of these cells rarely approaches the highest efficiencies attained under research conditions, the continued development of PV technologies has highlighted a plethora of potential options for energy generation. With many viable

options to choose from, it is important to assess the suitability of each potential PV technology to ensure the selection best suits the application.

The case for using PV for energy generation grows as these technological improvements progress through the development process to mass-produced modules. More efficient PV modules can produce more power per unit area, reducing the requirements for racking structures and other balance of systems costs, as well as lowering land resource requirements. These improvements increase the range of potential locations where PV can be installed and, as we will see in the next section, continue to reduce module prices.

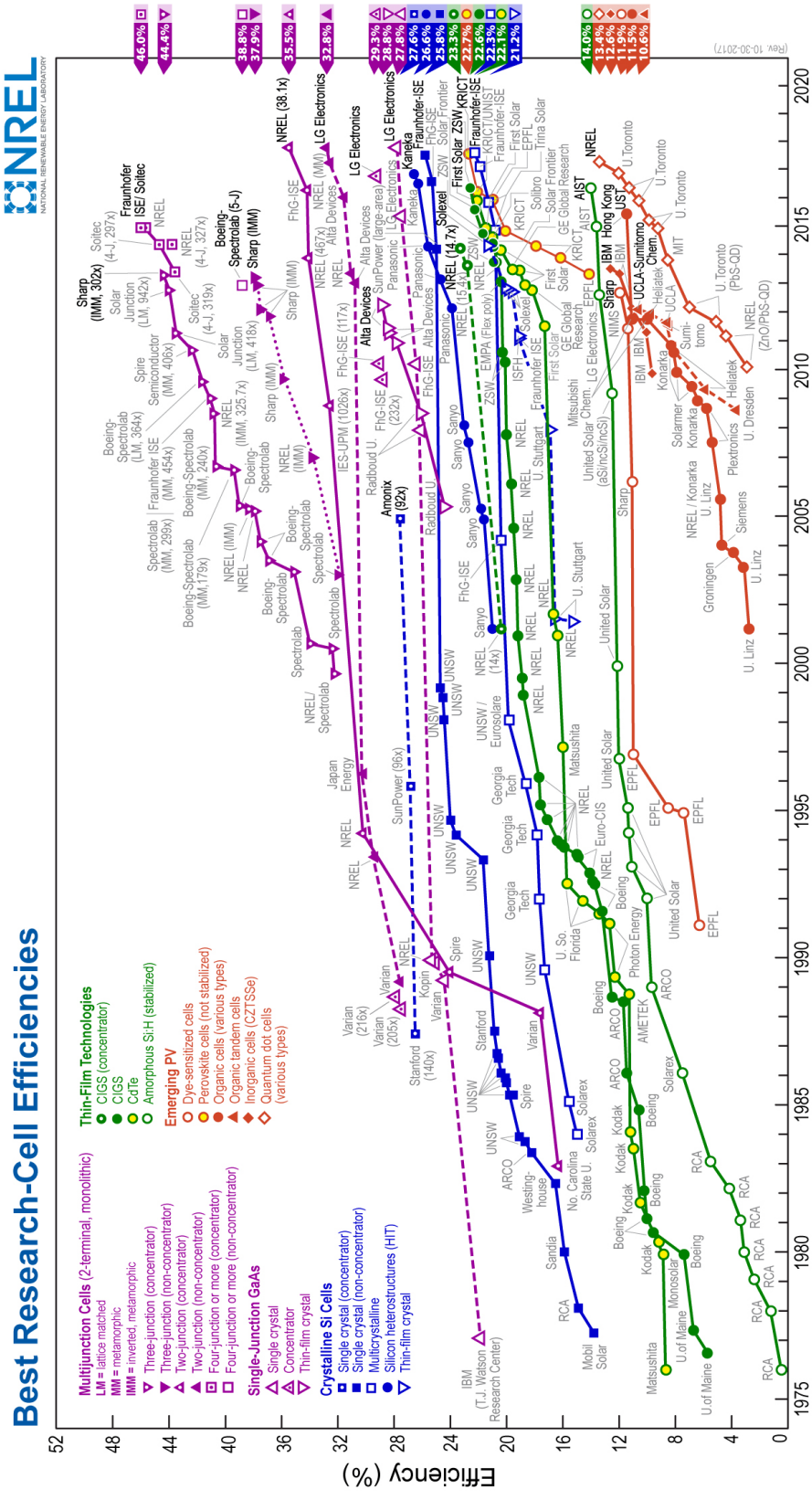


Fig. 1.1 The National Renewable Energy Laboratory Best Research Cell efficiencies, as of October 2017. This plot is courtesy of the National Renewable Energy Laboratory, Golden, CO. [3].

Cost decreases

The continued increase in PV technology efficiency has been accompanied by a similar decrease in the cost of modules. Swanson [6] predicted in 2006 that continued efficiency improvements, along with other factors, would be necessary for c-Si to continue experiencing its historic 20% cost reduction for each doubling of cumulative installed capacity of modules. Research by Fraunhofer Institute for Solar Energy [5] suggests that this phenomenon, dubbed Swanson's Law, continues to hold true: the learning rate in recent years has been estimated to be 24%.

These factors have resulted in a virtuous cycle and have lead to a significant and continuing increase in cumulative global installed capacity of PV. Total worldwide capacity was just 6 GW in 2006; five years later the cumulative installed capacity was recorded to be 70 GW, and five years after that it had reached 303 GW [1]. Of this, more than 94% of installed PV capacity is c-Si, with the remainder comprised mainly of thin films and small installations of other technologies [5]. The price of PV modules decreased by around 80% between 2009 and 2015 although an oversupply in the PV module market, exacerbated by unsustainable manufacturer margins, trade disputes and price floors, affected the long-term confidence in continued price decreases [7]. Nevertheless, the prices continued to decline and both c-Si and thin film technologies are available at historic lows of less than \$0.50/W_p [5].

Technologies become more accessible as improvements drive efficiencies higher and costs lower. The market-leading technology, c-Si, is in a dominant position and its low cost per unit capacity currently outcompetes other technologies, even if they can offer higher efficiencies. This presents an issue as to whether emerging technologies should continue to be considered as viable options for electricity generation. It is suggested that manufacturing innovations for OPV, for example, can significantly reduce its manufacturing cost if sufficient investment is given to its development [8–10]. Studies also suggest that CPV can be competitive if cost reductions across its components are realised [11–13], but with a cheaper option already

available, the penetration into the market of these two technologies may be stifled. Later in this work I will provide further analyses of the potential of these emerging technologies to compete against their more mature counterparts.

Feasability

One of the greatest advantages of solar PV is that it can be deployed almost anywhere, and at almost any scale. More than 24 countries have installed capacities of greater than 1 GW and electricity from PV sources currently accounts for 1.8% of total global generation [1]. At the utility scale, emerging markets saw significant installations in 2016 including 509 MW in South Africa, 583 MW in Turkey and 726 MW in Thailand [1]. At the opposite end of the spectrum more than 8 million small-scale lighting products, with capacities of 100 W_p or less, were sold in 2016, mainly in Sub-Saharan Africa and India [14].

Improvements in PV technologies have meant that it can be profitably installed around the world. Research by the Fraunhofer Institute for Solar Energy [5] reports that the costs of small-scale rooftop PV systems in Germany has decreased far enough to achieve grid parity, where the cost of electricity generated by a system is lower than the price of electricity from the grid network. Although Germany has a highly developed PV market which has assisted in reducing these costs, it has done this despite the relatively low irradiance in the country and the relatively high system cost compared to utility-scale deployment which illustrates the financial viability of even small-scale PV installations. Furthermore, increasingly competitive tenders from utility-scale projects, especially in in Africa and the Middle East, further demonstrate the scope of deployment of PV [15].

1.2.3 Emissions mitigation using PV technologies

Overview

After deployment, PV technologies require relatively little maintenance in comparison to other generation sources and are responsible for only small amounts of GHG emissions over their working lifetimes. This does not, however, mean that they are a zero-GHG technology: the manufacturing processes of PV can be energy intensive and emit significant amounts of GHGs which, it is hoped, will be offset over their lifetimes by reducing the need for power supplied by other sources, such as fossil fuels.

The process of accounting for the energy and GHG inputs is known as life cycle analysis or life cycle assessment (LCA). For PV technologies this is codified in the methodology described by Fthenakis et al. [16] as part of the International Energy Agency (IEA) PV Power Systems Programme which aims to unify the goals, scope and indicators for LCAs across different PV technologies and their applications. Their methodology defines the standards which PV LCAs should aim for in order to provide informative and comparable results.

Mature PV technologies

Mature PV technologies have been the subject of many LCAs. An extensively detailed breakdown of the embedded energy and GHGs of many kinds of c-Si and thin film technologies was presented by de Wild-Scholten [17] in 2013 which assessed each stage of the module manufacturing process, for example producing ingots and lamination, as well as the deployment and installation stages. The author found that the embedded GHGs for modules made in China were far higher than for those produced in Western Europe, however when these were averaged over the expected lifetime energy generation then the emissions intensity of both technologies was much lower than that of the grid network. Furthermore the time taken to produce more energy than was required to deploy the system, known as the energy

payback time (EPBT), of both technologies was found to be 1.5–2.4 years, far less than the system lifetime.

Fthenakis and Kim [18] presented an LCA review of four commercial PV technologies: mono- and multi-crystalline silicon, ribbon-silicon, and CdTe. They reported EPBTs in the range 1.0–2.7 years, with CdTe found to be the lowest. The authors also found that the GHG emission intensity of the technologies were in the range 21–37 gCO_{2eq}/kWh; again CdTe was the lowest, with a projection to fall to just 10 gCO_{2eq}/kWh in the future.

As incremental efficiency and manufacturing improvements continue, periodic reviews of the LCAs of PV technologies have been conducted by a number of researchers [19–22]. The PV LCA methodology guidelines suggest specific performance parameters to be used in each study for comparability [16] but these are not always adhered to. To overcome this issue researchers have used harmonisation processes, which reanalyse the data presented in each LCA using standard parameters, to reduce the variation between studies. One study, by Hsu et al. [23], screened 397 c-Si LCAs for quality and suitability and reported the median harmonised emissions intensity to be 45 gCO_{2eq}/kWh, 21% lower than the median emissions intensity reported in the studies. An analogous study by Kim et al. [24] screened 109 LCAs for amorphous silicon, CdTe and CIGS cells, finding median harmonised emissions intensities of 20, 14 and 26 gCO_{2eq}/kWh respectively. These review and harmonisation studies demonstrate that mature and commercially available PV technologies can produce electricity with far lower GHG emissions than incumbent sources and that deploying them could potentially mitigate GHGs that would have come from other sources.

The values calculated in these studies include considerations towards the balance of systems components but do not take into account any contributions from the infrastructure of the grid network, for example. This is typical and recommended for PV LCAs [16] but a false equivalency between these values for emissions intensity and those for off-grid minigrids, for example, should not be drawn. Later in this work I include further considerations such

as battery storage, a power distribution network, and the effects of dumping electricity which cannot be consumed by the community which are not taken into account by these grid-connected case studies. This provides a superior assessment of the situation but can result in the emissions intensities for renewables systems not connected to the grid appearing higher than expected.

Emerging PV technologies

LCAs of CPV technologies typically focus on the design of the module which houses the high-efficiency cells: as the concentrating optics and housings use far more material than flat-plate technologies, but a greatly reduced cell area, it is often the former which contribute the majority of the embedded energy and GHGs. Various studies [16, 25–30] since 2005 have performed LCAs of novel and distinct designs of CPV modules and systems and have reported EPBTs in the region 0.8–1.5 years and emissions intensities of 18–32 gCO_{2eq}/kWh. Both of these metrics are lower than those reported for many mature PV technologies. Although the CPV LCAs often assume deployment in high irradiance locations, owing to the requirements of the technology, these nevertheless suggest that CPV could provide a significant mitigation of GHGs.

Similarly, the development of OPV technology has inspired several LCAs based on expected future performance. Espinosa et al. [31] projected that, given improvements in manufacturing processes [32], OPV modules could be produced and deployed with EPBTs of just a single day. Furthermore, Emmott et al. [33] suggest that, despite the short lifetime of OPV, the low embedded energy and GHGs of its production could lead to OPV having a greater potential for mitigating GHG emissions than mature technologies.

Owing to their nascency, emerging PV technologies have not been the subject of as many LCA studies; nevertheless, at any stage of maturity an LCA can help provide evidence for or against the further development of a technology. If its eventual deployment can be shown to

have the potential to greatly reduce total GHG emissions, for example, then this may motivate technological progress even if the current cost or performance lags behind established PV technologies.

1.2.4 Gaps in the literature

PV technologies are being widely researched and developed by academia and industry. Mature technologies have more than proven their potential: accelerating annual capacity additions and decreasing costs show that the technology is continuing its development and becoming more accessible. The environmental analysis of mature technologies has shown that the deployment of PV can provide electricity with a lower emissions intensity than other generation options, especially fossil fuels, and that the EBPTs are much lower than the system lifetimes [17–24]. Even emerging technologies, whose ultimate potential may not yet be known, are projected to be able to provide significant benefits in terms of GHG mitigation [16, 25–31, 33].

In this work will focus on the mitigation potential of PV technologies in two contexts: the application of emerging PV technologies in established scenarios, and the applications of PV technologies in emerging scenarios. In the former, I will provide a continuation of the existing literature for CPV LCAs in assessing a novel design of a CPV module which reduces its materials usage in order to lower its environmental impact. I will also assess the potential of CPV and OPV technologies in meeting the needs of a rural community in India, potentially mitigating the use of diesel generation or the national grid network.

For the latter I will also explore the potential of mature PV technologies in providing electricity to rural communities in India. Furthermore I will extend the investigation into the application of the dominant PV technology, c-Si, as part of a novel energy systems modelling framework described later in this work with a focus on the case of remote villages in Uttar Pradesh. This process, combined with other analyses, will quantify the potential of existing

PV technology in providing sustainable energy access for rural communities in India and mitigating GHG emissions from fossil fuels.

1.3 Electricity access

1.3.1 Introduction

More than 1.1 billion people around the world live without access to electricity [34] and approximately 1 billion more lack a reliable, affordable and safe connection [35]. Significant efforts have been made towards achieving the Sustainable Energy for All (SE4All) goal of universal energy access by 2030 and to achieve the cobenefits of electrification [2]: Alstone et al. [36] showed, for example, that countries with higher rates of electrification also had higher rates of children gaining a primary education, higher proportions of women enrolled in universities, lower proportions of people living in absolute poverty and lower rates of maternal deaths during childbirth. Despite this, government programmes to increase the proportion of households with electricity have been criticised, often justifiably, as ineffective, misguided or poorly planned [37–41] and traditional sources of energy, such as kerosene for lighting and biomass for cooking, are still relied upon by more than a billion people worldwide [34]. Overcoming a challenge of this scale will require a paradigm shift.

Technological developments can help in achieving greater levels of electricity access. For PV in particular, the improvements in efficiencies and decreases in costs described in section 1.2.2 has expanded both the potential geographic range and the number of people that can afford systems supplied by PV. Consecutive years of increasing annual sales of solar lighting products, such as solar lanterns and solar home systems, has facilitated hundreds of millions of people in receiving basic electricity access for the first time [14] and the growth of minigrid systems in developing countries has seen a similarly promising increase [2].

In this section I will present the definitions and methods of quantifying energy access, the technologies that can be used to provide electricity, an overview of the sustainability of energy access, and a focus on the situation of energy access in India.

1.3.2 Defining electricity access

The electrification rate, defined to be the proportion of either people, households or communities with access to electricity, is a widely reported but misleading statistic. Data provided by the World Bank shows that worldwide electrification rates have increased from 73% in 1990 to 85% in 2014, with rural electrification rates lagging at around 10% (absolute) below these [42, 43]. The same source shows that India, for example, has increased its rural electrification rate from 32% to 70% over the same period, but these numbers can be misleading: defining electricity access as a binary measure fails to capture many important features of electricity provision such as the reliability of service and the amount of energy consumed.

To overcome this, SE4All developed the Global Tracking Framework which, amongst other things, stratifies energy access into tiers corresponding to the quality of service received [2]. A summary of the indicators related to power capacity and duration for each tier for household electricity is shown in table 1.1; in addition to these, SE4All includes criteria for affordability, legality, quality and health and safety which are necessary in reaching the highest tiers of access. Tier 0 corresponds to no access to electricity and that a household relies on sources such as kerosene lamps or candles for lighting, if anything at all, for lighting after dark. At the other end of the spectrum, Tier 5 corresponds to the level of electricity service that is available to grid-connected households in developed countries. Analogous frameworks also exist for productive electricity uses, energy for cooking, electricity for community facilities and more.

Table 1.1 Criteria for electricity capacity and duration from the tiers of access for domestic electricity supply per household, summarised from Sustainable Energy for All [2]. Other criteria include the affordability, legality, quality and safety aspects of electricity supply.

Electricity supply attribute	Metric	Tier					
		0	1	2	3	4	5
Peak capacity	Power (W)	-	3	50	200	800	2000
	Daily capacity (Wh)	-	12	200	1000	3400	8200
Duration (hours)	Per day	-	4	4	8	16	23
	Per evening	-	1	2	3	4	4

Tiers of energy access allow a more detailed assessment of the quality of energy provision and help to highlight rural electrification issues. A household in a remote area with a connection to the national grid could attain a Tier 5 rating for peak power capacity, but if the supply is so unreliable as to provide only a small number of hours of service per day, the level of access may be better reflected as Tier 3, for example. In this scenario using the highest, lowest or average tier obtained for the representative criteria may be unreflective of the true level of electricity access.

The IEA instead defines electricity access as the availabiity of an initial basic bundle of services, including at a minimum several lightbulbs, task lighting, phone charging and a radio, which increases over time to reach a regional average [34]. This definition is more challenging to use quantifiably but offers a number of advantages. Defining energy access in terms of the energy services available means that electricity access is decoupled from electricity consumption, which is particularly useful as the greater penetration of high efficiency devices entering the energy access market means that the same benefits to households can be achieved at a lower energy cost, making the delivery of services more efficient [34]. In this work I choose to abstain from assigning a Global Tracking Framework tier to the households and communities to avoid misrepresenting their situation, and instead favour the IEA approach of supplying, at least, basic energy access with the goal of increasing it over time.

In this work I consider only energy access related to the provision of electricity. Energy access for cooking, whilst an incredibly valuable and impactful topic of research, faces many additional challenges which PV technologies are less suited to solve. Investments in clean cooking programmes worldwide could help bring sustainable energy for cooking to the 2.8 billion people that currently live without it [34] but, in this work, I will focus only on energy access in the context of electricity.

1.3.3 Providing electricity access

Overview

SE4All estimates that the global investment in electrification services will need to grow from $9 billion per year in 2012 to $45 billion per year in order to meet their target of 100% electricity access by 2030 [2]. Despite this deficit the investments that are being made are increasingly diversified across several electrification options: previously government-sponsored electrification programmes would favour large infrastructure projects such as power plants and grid extension however as technologies have improved the shift towards decentralised generation has accelerated. In this section I will outline three of the most common present strategies: grid extension, solar home systems and minigrids. In this work I do not consider small-scale solar lanterns as their ability to provide more than basic energy access is limited [34].

Grid extension

A national grid network provides centralised generation from large-scale energy production facilities and distributes it through a high-voltage power network to consumers around the country. This has a number of advantages: the economies of scale of utility-scale power plants reduce the cost per unit of electricity; generation sources can be diversified to provide a mix of baseload and dispatchable power to meet fluctuations in demand; and the aggregation

of a large number of energy consumers allows for a robust prediction future electricity loads, which means that electricity producers can plan the generation strategies in advance. As new technologies become cheaper they can be integrated into the energy system and complement existing generation to provide power at a low cost and, in the case of renewables, lower GHG emissions.

One of the issues with electrification via the national grid network is that, in the case of developing countries, many rural and remote areas lack existing grid infrastructure. To take advantage of large-scale power generation would require a country to invest in additional grid infrastructure, for example pylons, transmission networks, substations and potentially new power plants, which may not be cost effective. Grid extension is worthwhile if a large enough community can consume sufficient power to overcome the costs of its investment but this may not be possible for small rural hamlets and villages which, before electrification, would have little or no incumbent electricity demand. Challenging terrain such as mountainous regions invoke a further cost which may make grid extension economically impossible [44]. Furthermore, in some countries the rate of grid expansion is so slow that the number of people without electricity is increasing as population growth outpaces new connections [35].

Connecting a community to the national grid may force upon them a poor level of service. Remote areas in particular are more likely to experience load shedding or unpredictable periods of electricity supply [45] over which the communities will have little control. Communities that are geographically distant from generation sources will also suffer greater transmission losses, which in India for example can be as high as 19% [46]. Finally an extension of, and connection to, the national grid will supply the community with electricity generated by existing power plants which will be reliant on established fossil-fuel generation in many countries. It is estimated that nearly all of the people who gained access to electricity between 2000-2016, more than 600 million people, did so through through new grid connections supplied mainly via fossil fuel generation [34]. Although renewables penetration at the

grid scale is increasing, it may mean that these communities have missed an opportunity to access a more sustainable energy future from the start.

Solar home systems

A solar home system (SHS) is designed to serve the needs of a single household and to be entirely independent of the national grid network. Typically a SHS is composed of a PV panel for generating electricity, a battery and charge controller for storing electricity, and a basic wiring system to connect these components to a small number of appliances such as lights, phone chargers and entertainment devices such as televisions and radios. The reduction in costs of PV and battery technologies, amongst other factors, have facilitated a tremendous growth in SHSs across the world: in 2016 more than 8 million SHSs were sold, an increase of more than 41% on the previous year [14].

An advantage for SHSs is that they can satisfy the basic needs of a single household regardless of location; even the most remote households can use a SHS to supply power independently of any outside intervention if the solar resource is adequate. Furthermore, by targeting only a single consumer, many of the challenges of community-focused electrification are overcome as it is not necessary to reach a minimum threshold number of households in order to make electrification viable, as might be necessary for larger-scale systems. This independence and individual agency facilitates more straightforward electrification pathway for those that can afford them.

SHSs may be limited by their technological capacity. As a single-household electrification option the system is restricted in terms of its energy generation and storage potential: whilst it would be possible to include larger PV panels or batteries, systems are generally designed for basic energy access only which restricts them to a smaller number of low-power devices. The Global Off-Grid Lighting Association and Lighting Global [14] highlight that a SHS with 50–100 W_p of generation capacity can be used for lighting, phone charging, televisions, fans

and radios, and even some conventional appliances, but in 2016 systems in this represented less than 6% of systems sold and less than 15% of revenues of all systems of up to 100 W_p. This suggests that the most popular systems have low capacities and low functionality; whilst this is suitable for providing basic energy access, many SHSs will be unable to incorporate a growth in demand for higher-power electricity services and ultimately will need to be replaced in favour of another electrification option.

Minigrids

Minigrids provide rural electrification at the community scale. At their most basic they are composed of a source of energy generation, a distribution network, and a collection of devices or loads which demand power; minigrids powered by renewable sources will also typically use batteries to store energy during times when the generation supply is unavailable, and will likely also have a charge controller, electronic control systems to regulate the distribution of power around the network, remote or inbuilt payment systems, and inverters or rectifiers if necessary to convert between direct current (DC) and alternating current (AC) as required.

I use the word "minigrid" to refer to any system that features decentralised power generation or storage and serves a community in its immediate vicinity. At this stage I will not define a community size but in the context of rural electrification this could be of any size from a hamlet with tens of households to a village with hundreds of households, or a group of nearby villages with thousands of households. In the literature these systems are typically referred to by different names depending on their generation capacity: minigrids (10 kW–10 MW), microgrids (1–10 kW) and nanogrids (up to 1 kW) are often used interchangeably depending on the context [47]. In this work, for clarity, I do not use generation capacity to distinguish between these terms and instead refer to all of the systems that match the description given above as minigrids. Furthermore I use the convention that minigrids

can either be off-grid and entirely independent of the national grid network, or on-grid or grid-connected meaning that they can be supplied by the grid [15].

Minigrids hold an advantage over SHSs in that they can use economies of scale in sizing their generation and storage capacity and, in doing so, can both reduce costs and increase the types of energy services they provide [2, 34, 47]. The concepts around sizing and optimising minigrids are explained in more detail in section 1.4. Unlike many SHSs, minigrids can exploit the modularity of PV and battery technologies by replacing, upgrading and increasing capacities as necessary as demand for electricity services grows [34]. Compared to the national grid network, minigrids can potentially be deployed in any location with sufficient access to a generation resource regardless of how remote the community may be or how far from existing grid infrastructure.

Minigrids are not without their limitations. They rely on a sufficiently dense population to reduce the costs of the distribution network and typically need to ensure a minimum threshold number of customers before a system can be installed [47]. Furthermore electricity from minigrids is typically more expensive than that from the national grid, and if grid extension reaches a community where a minigrid is deployed then the minigrid system is at risk of losing its customers and becoming a stranded asset [34]. This can be a significant threat to existing minigrid systems and is an obstacle to new systems being installed, impeding the deployment of otherwise viable renewable energy systems and compromising sustainable development. This risk can be mitigated by ensuring the minigrid transmission and distribution network is compatible with the national grid however in many countries the necessary technology regulations and government policies which would incentivise this are either not followed, not enforced or not present [34].

Despite these challenges, I choose minigrids as the focus for this work. Minigrid systems offer the greatest potential for innovative methods of PV integration and system design whilst maintaining a frontline position in providing electricity access to unserved communities.

The IEA predicts that, by 2030, more of the total worldwide rural electricity demand will be served by minigrids than by national grid networks [34]. It also predicts that 34% of a $334 billion cumulative investment in electricity access between 2017–2030 will be spent on minigrids, of which 90% will be spent on renewable generation and, in particular, PV. This suggests that PV minigrids are in a strong position to provide electricity access on a global scale and that significant analysis will be needed to ensure that systems are deployed as effectively as possible.

Sustainable electricity access

Sustainable electricity access is a common goal for policymakers, practitioners and researchers. Affordable and clean energy is one of the United Nations Sustainable Development Goals and providing it to rural communities can help in achieving several of the other goals including poverty reduction, promoting economic growth, reducing inequalities, creating sustainable communities, and taking action to protect the climate, as well as others [48]. Ensuring that these are achieved and that an electrification project is a long-term success, however, can be challenging.

Ilskog [49] describes five areas in which the sustainability of a rural electrification project can be assessed. The project must be technically sustainable as it needs to conform to national standards and perform as expected to regularly provide the anticipated service; it must also be economically sustainable in terms of its capital and operational expenditures, its profitability, its ability to develop productive uses and generate employment. It must be socially sustainable by providing public services and connecting an appropriate share of the households in the community; it should also be environmentally sustainable both globally, in terms of GHG emissions, and locally, in terms of noise and particulate emissions. Finally it must be institutionally sustainable by ensuring a degree of local ownership or buy-in, maintaining a customer satisfaction in the long term, and remaining operational. Ilskog

suggests the use of these indicators, and more, as part of a wider methodology for assessing sustainability; although it is not critical that every criteria is met, it should be the aspiration of any project to achieve as many as possible.

Hirmer and Cruickshank [50] also describe a framework for assessing sustainability but from the perspective of the user of a rural electrification system. The user considers the functional value of a system to be its cost to the user, any economic benefits they gain from using it, its quality, performance and reliability, its ease of use and convenience, and its suitability to their needs. Social significance value includes the prestige of owning or using the system and the sense of group belonging in community projects. Epistemic value describes the novelty of the system and satisfying curiosity, and emotional value is associated with the safety, entertainment or memorability of using a system. Finally, cultural value respects considerations towards traditions and religions that should be accommodated. The authors propose that these values should be satisfied in order to ensure the users appreciate the benefits of the electrification project, but assessing the overall user acceptance of electricity systems is beyond the scope of this work.

Technology improvements are also driving sustainability. Efficiency improvements in PV technologies have been accompanied by reductions in embedded energy and GHGs per unit of capacity, reducing the environmental impact of systems [17, 18, 31]. Furthermore, high-efficiency devices are expected to play an increasingly prominent role in providing energy access [35]. By reducing the energy required to provide the same level of service, a higher initial investment in efficient devices can decrease the necessary capacity for energy generation and storage, reducing the average cost for a typical rural household by 32% [34].

In this work I will prioritise three measures of sustainability. Firstly, the project must be technologically sustainable and should provide a predefined level of electricity reliability throughout the system lifetime. Secondly, the project must be financially sustainable; in the absence of a detailed analysis of business models and financing that would be beyond the

scope of this work, I will instead use financial comparisons between prospective projects that provide similar levels of service in order to select the superior option. Finally, I will use global environmental sustainability, namely the GHG emissions of each project, to assess the overall impact in mitigating GHGs either in comparison to other potential projects or an incumbent baseline scenario.

1.3.4 Electricity access in India

Bhattacharyya [37] estimated that, in 2006, 40% of the world population without access to electricity lived in India. Improvements have been made to increase the number of people with access to electricity, achieving an annual growth rate of 1.5% per year, but recent estimates suggest that more than 250 million people, now around one quarter of the worldwide total, still lack basic access and the majority of them in rural areas [2, 34].

Grid extension for energy access has been the main focus for the Indian government [51]. In India around 75% of the energy now being used by populations who previously lacked access is sourced from coal-fired power plants, with only around 20% from renewables generation [34]. Jain et al. [52] undertook and analysed an extensive survey of energy access in six northern states of India and found that present quantifications of electricity access used by the Government of India and others were inadequate and unrepresentative. Of the households that had a grid connection nearly 50% were found to be in the lowest tier of electricity access, defined by a framework similar to that of SE4All [2]. Two-thirds of households that did not have a grid connection, but were close enough to receive one, chose not to and typically cited that the grid supply was insufficiently reliable and not affordable. The authors also found that the flagship Rajeev Gandhi Grameen Vidyutikaran Yojani and Deendayal Upadhyaya Jyoti Yojana electrification plans were successful in increasing the extension of the grid to rural communities, but also discovered that the median lag time between a household being able to connect to the grid and it actually being connected was

15 years in Uttar Pradesh. The same state was found to provide an average of only two hours of grid electricity per evening, the lowest of the six states surveyed.

Recently there has been a shift towards decentralised electricity access via minigrid systems. Schnitzer et al. [53], in a 2014 report for SE4All and the United Nations Foundation, identified 750 minigrid systems in India; typically these had between 10–400 customers each and had a total installed capacity of 8.2 MW. More than 75% of these systems were supplied by PV and 18% had their electricity sourced from biomass gasification. In 2016 the first policy document for renewable energy minigrids was published by the state of Uttar Pradesh [54]; amongst other details, it outlines subsidy mechanisms of up to 30% for renewable energy minigrids. Also in 2016 a draft national renewable energy minigrid policy was published with the goal of establishing 10,000 minigrids in India with an installed capacity of 500 MW [34], and in the same year the Rockefeller Foundation announced a new initiative which will support several local companies in deploying minigrid systems in 1000 villages around India [15].

India is expected to achieve universal energy access in the early 2020s with renewables expected to account for 60% of this additional supply of electricity [34]. This will be more challenging for some states than others: the Census of India records that the predominantly rural state of Uttar Pradesh is the most populous state in the country [55] and it is also home to the greatest number of people without access to electricity [56]. With a particularly unreliable grid network and a poor record of connecting households even when the grid is in the vicinity [52], the state government was the first to demonstrate a willingness to both regulate and support the deployment of minigrids through favourable policies [54]. For these reasons I choose India for my analysis and, in the later stages of this work, I will further focus my efforts on the state of Uttar Pradesh.

1.3.5 Gaps in the literature

Access to electricity, both worldwide and in India, has received significant attention in the past and will continue to be researched until the goals of SE4All have been achieved. All of the technological routes for rural electrification are being explored in a variety of contexts and with different goals but evidence gaps in the literature remain. Minigrids are expected to play a larger role in providing future energy access [15, 34, 47] but their potential to grow in capacity over time, in line with the objectives of increasing the quality of electricity access, has not yet been explored in detail. The ways in which electricity demand will grow, both as communities have greater access to devices and higher-power appliances for productive uses, has also not been modelled in the context of minigrids with increasing capacities. Furthermore the cost associated with this strategy, and the GHG emissions that could be mitigated from fossil fuel generation and kerosene for lighting, have not been quantified. Additionally the potential for different PV technologies, rather than only mature c-Si PV, in meeting the needs of rural communities has not yet been considered. In this work I will consider both of these issues in my analysis of PV minigrids in rural India.

The primary data being collected by researchers at present typically aim to capture a snapshot of energy access, for example the types of energy services that households have access to, the needs and priorities of respondents, or socioeconomic characteristics such as income, expenditures and occupations [52, 55]. Primary data on the times at which people use energy services, for example, is insufficiently explored despite being a key input in the field of energy systems modelling, as I will discuss in section 1.4. For this reason I will expand the literature by gathering survey data from rural Indian communities in Bahraich District, Uttar Pradesh which can be processed and integrated into minigrid simulation and optimisation models to increase the robustness of my assessment.

1.4 Energy systems modelling

1.4.1 Introduction

Simulating minigrids using energy systems modelling allows designers to explore the feasibility of different combinations of power generation and load demands in a well-defined, controllable environment. Using computer modelling allows researchers to assess technological performance under a variety of conditions and explore scenarios at a far lower cost than empirical assessment of either hardware components in a laboratory or an installed system in the real world. Furthermore, energy systems models allow us to define and identify systems which are most suitable for the context, in this case in supplying reliable and sustainable electricity to rural communities.

In this section I will provide a review of the most commonly used minigrid simulation software, HOMER, and another tool which explores different functionality, ESCoBox. I will then present a variety of other minigrid simulation models before identifying gaps in the literature which are not adequately explored by other studies, if at all.

1.4.2 Modelling minigrid energy systems

HOMER

The most commonly-used minigrid simulation tool by those in academia and industry is HOMER (Hybrid Optimization of Multiple Energy Resources) [57]. HOMER is a commercial software developed by NREL for designing minigrid systems and can simulate and optimise systems powered by established off-grid generation sources, such as PV, biomass, wind, and hydropower, and also more novel sources such as hydrogen and flywheel storage. It can also integrate power from diesel generators and a grid network of a specified reliability.

Bahramara et al. [58] presented a recent review of how HOMER has been used in academic literature. For its key inputs, HOMER uses monthly averages of meteorological

data to synthesise and estimate the power generation of a source and uses recorded time series data or predictions as the load profile to be satisfied. The HOMER user defines a search space of potential generation options, composed of allowable generation sources of defined maximum and minimum capacities, and using libraries of technical performance and cost data the software simulates every combination of these to identify the system with the lowest net present cost. The user can also specify constraints on the viability of a system and, after the optimisation process, further analysis can be performed to assess the sensitivity of a system to a given parameter, for example renewables resource. In their analysis of 91 articles which use HOMER, Bahramara et al. [58] report that HOMER has been used mainly for analysis for remote and rural areas in developing countries, that the most popular generation source was solar PV, and that standalone off-grid systems are assessed more commonly than those with a grid connection. The net present cost of the system, capital and operational costs, renewable fraction, cost of electricity, breakeven grid extension distance and GHG emissions per year are outputs of the HOMER optimisation process: of these, the authors state that the cost of electricity is the most appropriate, and the most common, criterion for selecting the optimum system.

HOMER has been used many times in analysing on- and off-grid energy systems in India under a variety of conditions. Sen and Bhattacharyya [59] analysed hydropower, PV, wind and biodiesel generation for an off-grid village in Chhattisgarh and found that hybrid combinations of technologies were both more cost effective and produced lower GHG emissions than grid extension. Rajbongshi et al. [60] found that costs of electricity as low as $0.07/kWh can be achieved using grid-connected PV-biomass-diesel systems in Assam; when considering off-grid systems, the same authors found very low breakeven extension distances of only 1–7 km. Ramchandran et al. [61] performed a feasibility assessment of minigrids supplying anchor loads, such as telecoms towers, businesses and communities in Uttar Pradesh and concluded that PV systems presented the most robust business case, whilst

biomass and PV-biomass systems would also offer satisfactory returns on investment. Finally, Kobayakawa and Kandpal [62] explored the potential of system expansion by simulating the requirements of a community in West Bengal before and after an increase in demand caused by connecting more households and including productive loads; they achieved this using HOMER by performing two discrete optimisation stages. Many other studies identified by Bahramara et al. [58], use HOMER to investigate other combinations of technologies, energy demand and scenarios in India [63–68].

ESCoBox

Despite its proven functionality, researchers and practitioners can be limited by the confines of the HOMER structure and so develop their own methods of analysis. One example is ESCoBox, designed to be a decision support tool for analysing and assessing minigrid systems supplied by either PV and battery storage or hydropower. In the description of the tool by its designers, Boait et al. [69] present several simulation and analysis modules. The first is the calculation of community demand, which builds a bottom-up load profile using a Monte Carlo simulation based upon the ownership of devices and the probability that they will be used during a given hour of the day founded upon their earlier research [70], and a battery condition model which, they state, is more robust than that used by HOMER. They also outline a method of demand control: using software that controls hardware installed in a minigrid system, they present how loads can be simulated and scheduled *in silico* and switched on and off *in situ* to avoid exhausting the available energy resource. They present an application of their tool in minigrids in Kenya and The Gambia and an initial release of their software is available for free download [71].

Aside from the innovative hardware control capabilities, which is not directly relevant to this work, the simulation processes used by ESCoBox present improvements over those used by HOMER. An improved treatment of electricity demand captures the variability and risks

of supplying power to a community with a previously unknown load demand, and the ability to model the integration of higher-power productive loads into an existing minigrid simplifies somewhat the process of reoptimising the system. As a new software still under development the simulation capabilities of ESCoBox are more basic than HOMER, but elements of it provide a valuable extension for energy systems modelling.

Other minigrid modelling approaches

Many other minigrid simulation, optimisation and decision support tools have been reported in the literature and so in this section I will describe a select number of relevant examples. Kanase-Patil et al. [72] present a model which simulates the usage of hybrid combinations of hydropower, biomass, biogas, wind and PV for several static load profiles in representative months of the year, optimised to minimise the cost of electricity to a community in Uttarakhand. They found that the seasonal effects of generation and demand have an effect on the optimum system design and advocate a strategy of designing systems to satisfy demand in the most challenging months to ensure system reliability.

Louie and Dauenhauer [73] use a simple model for PV and battery systems to provide an insight into the effects of load estimation error and reliability requirements on system sizing. They conclude that overestimating energy demand has a significant negative impact on system design and that allowing small reductions in reliability can greatly reduce costs. Accepting 99% reliability in a system rather than 100% reliability, for an example system in Malawi, was found to reduce the costs of PV minigrids by 46%.

Shang et al. [74] have developed a novel particle swarm optimisation model to assess minigrid systems composed of either PV or wind generation in combination with battery storage and diesel generation. Focusing on the sizing of the battery storage, they simulate clusters of similar systems but include random perturbations in component sizes to allow their algorithm to find the global, rather than only the local, optimum system in terms of

the lowest cost of electricity. They use their model to investigate systems of predefined renewables penetration located on islands near Singapore and find that off-grid systems can supply power with costs in the range of $0.18–0.26/kWh.

Finally, Cader et al. [75] use a different approach in simulating systems to identify regions of the world where PV-battery-diesel systems would outperform diesel-only systems. Using geographic information system software they analyse solar resource, diesel prices, transport costs and other factors in comparing the two designs of off-grid systems to highlight the regions where each configuration is more favourable. The methods that the authors use to simulate and assess the system designs are relatively basic, comparing relevant calculations of electricity costs rather than the simulation of systems over their lifetime, however the geographic scale of their assessment means that their work has a significant impact. In India, for example, the authors conclude that the cost of electricity from PV-battery-diesel hybrid systems, at around $0.42/kWh, is 28% cheaper than power supplied by diesel-only systems.

1.4.3 Gaps in the literature

Chaurey and Kandpal [76] provide an overview of the gaps in the literature concerning the usage of PV for decentralised electricity access in India. Amongst other factors, they identify that providing electricity for productive activities, facilitating an increase in the community demand as level of electricity access improves over time, using high-efficiency DC devices, exploiting the modularity of PV and storage technologies, and the usage of hybrid power generation are the topics that have not yet been explored in adequate detail. I will therefore consider these factors in my work.

Despite the capabilities of software such as HOMER and additions to the minigrid modelling literature by others, there remain areas which are not yet adequately explored. Many studies, especially those using HOMER, do not state the PV technology being used for solar generation [60–62, 72]; whilst it is more relevant in the context of these studies to be

instead more focused on the installed capacity of the systems, the implicit assumption that c-Si is the default or only technology choice may limit the potential for research into other technologies, and in particularly emerging technologies.

The majority of the studies reviewed here aim to provide a completely reliable supply of electricity. This is a noble aspiration and one that should be encouraged to avoid customer dissatisfaction but, in the case of rural minigrids, this may lead to system oversizing. Only a small number of studies [72, 73, 77] identify the opportunity to allow small shortfalls of electricity provision to gain significant cost savings. HOMER allows users to schedule the times of power availability and to define periods during which energy is not supplied, but the literature does not present any consideration of the demand for energy services that goes unmet during these downtime periods and the resulting GHG emissions from backup sources such as kerosene lamps. As rural electrification typically results in the first time that a community has access to electricity then providing an adequately, but not completely, reliable supply of electricity without the need for scheduling may mean that costs can be reduced and a greater number of communities can be reached for the same investment. Furthermore, the integration of minigrids and an unreliable, rather than scheduled, grid network has not been explored in detail.

HOMER and other simulation tools require a definition of the load that the minigrid systems they design are required to meet. In many studies this is a static repeating daily profile [60, 74, 75] or with a small amount of variance [58] to represent the demand of the community. Some studies include seasonal variation [61, 72] but this is done typically through the use of discrete example months rather than as a smooth transition over the year. This potentially represents a difference in the way energy generation and energy demand are treated, as the former is often synthesised to vary across the year, which could affect the validity of the results. Methods to overcome this are included in the ESCoBox model and associated work to better represent the variability in energy demand [69, 70]. Other studies

rely on data gathered from installed systems [73, 78] but, especially in the case of designing new systems, these data may be impossible to gather.

The growth of electricity demand has not been adequately explored. Projections for economic development and the goals of international agencies suggest that the electricity requirements of communities will grow over time from basic services to reach a regional average [34] but the literature described in this section does not sufficiently capture this expectation. Kobayakawa and Kandpal [62] explore this by introducing a greater number of connections and productive loads but the modelling process does not facilitate the gradual diffusion of new products into the community over time and the effects this will have on the performance of the minigrid. The potential to reoptimise a minigrid system over its lifetime, which would exploit the modularity of PV and storage technologies to meet a growing electricity demand, has not yet been been explored.

It is most common in the literature to design a minigrid system for a given case study example, such as a specific village in a given region with a specified level of service. This means that the work is directly relevant to an identifiable beneficiary and it can be assumed that similar systems installed in similar locations will have similar impacts, but makes extrapolating to other situations more difficult. Providing a broader analysis, for example presenting the impacts of systems at a continuous range of component prices or reliabilities, may help achieve a greater understanding of the scenario and could be used to draw more general conclusions. At some point, however, the parameters of even the most general system must be defined in order to be realistic and in doing so a degree of specificity is assigned.

Finally, HOMER and other tools have the functionality to quantify the GHG emissions and the renewables fraction of generated energy for the minigrid systems [59, 60] but this is often not reported in favour of instead assessing systems on grounds of cost only. Although this is a more practical metric in determining the suitability of the system [58] it assumes that, as a system is powered by renewables, then its environmental impact is minimal and is

a beneficial addition to the energy system. Whilst this may be true, it is also the case that quantifying the benefit of minigrid systems, and particularly those supplied by PV, can further demonstrate their value in achieving the Sustainable Development Goals and incentivise their deployment. Furthermore, whilst some studies provide comparative analyses of different systems to assess their relative merits, none of the literature reviewed here uses energy systems modelling to quantify the reduction in kerosene usage that a reliable electricity supply can achieve and the resultant benefits of mitigating these GHGs.

1.5 Summary

1.5.1 Literature summary and research gaps

In this chapter I have reviewed the potential for PV technology to provide reliable, affordable and sustainable electricity. PV is in a unique position: its low cost and continuing technological improvements mean that mature PV can be deployed in new applications and that emerging technologies may provide possible alternatives to established technologies. PV has a proven potential to mitigate GHG emissions from fossil fuel sources but a greater quantification of this, particularly with regards to recent developments in emerging technologies, is required.

Providing sustainable electricity access to rural communities is an important goal. Minigrid electricity systems can provide decentralised electricity flexibly, affordably and without the need for costly grid infrastructure. They are being increasingly incentivised in India, home to the largest number of people without electricity access in the world, and in the coming decade minigrids using PV technologies are expected to supply thousands of rural communities with electricity for the first time. One of their key features, the flexibility of the design and ability to integrate greater capacity as electricity access increases, has not yet

been explored and in doing so I will expand the body of evidence supporting the usage of PV for rural electrification in case study communities in Uttar Pradesh, India.

One could use energy systems modelling to do this but, at present, many of the existing models are not adequately capable in accurately representing this. Growing the system over time, accepting different thresholds of reliability, accounting for fluctuations and growth of electricity demand, and quantifying both the GHG emissions of the minigrid and its potential to mitigate GHGs from other sources are not captured in models in the literature. For this reason I will present both the design of a new model which aims to encompass these issues and an assessment of its application to rural communities in India.

1.5.2 Key research questions

PV technologies have a significant potential to mitigate GHG emissions in many contexts around the world and in a vast range of applications. In this work I aim to assess this potential but to do so I choose to focus on the applications of PV for GHG mitigation in two specific areas: for rural electrification in India and by using the emerging technologies of OPV and CPV. Assessing the overall GHG mitigation potential in these two cases will be dependent on answering further questions: in the situation being investigated, can PV technology be deployed successfully and economically? And if so, does it provide an opportunity to reduce the total GHG emissions that would otherwise be released if it were not deployed? Using these two subquestions I will first address whether or not PV technologies have the potential to be deployed, and second I will assess their benefit in mitigating GHGs if they were to be deployed.

The first task is to demonstrate the technical viability of PV and its potential to be deployed in real-world situations; to do this I use energy systems modelling and comparisons to incumbent technologies to assess whether a PV minigrid, for example, can provide an economic benefit in comparison to a diesel generator for supplying electricity to a community

in rural India. The second is to quantify the benefits of the PV technology in terms of its lifetime GHG emissions which I perform using life cycle analyses of technologies and energy systems, for example of a new design of HCPV module. By addressing these questions, throughout this thesis I will aim to answer the overarching research question: what is the potential for PV to mitigate GHG emissions for rural electrification and by using emerging technologies?

In chapter 3 I will ask the questions of what the costs and GHG emissions of using different kinds of mature and emerging PV technologies would be in minigrid systems in rural India, whether PV systems would have an advantage in comparison to diesel generation and grid extension, and what the impact of future costs would be on the optimum hybrid systems and their emissions intensities. In chapter 4 I will ask what the lifetime impact of a new design of CPV module is, how it compares to others in the literature, what environmental impact it would have in various deployment locations around the world, and what GHG mitigation potential it would have in comparison to other renewable technologies and the national grid. In chapter 5 I will ask what the current energy access situation is in rural communities in Uttar Pradesh, India is, what costs and GHG emissions are typical of incumbent energy use, what benefits providing sustainable electricity access would bring, and what would be the implications of variations in energy service demand with regards to sizing electricity systems.

In chapter 6 I will ask how energy systems modelling can be used to understand growth in electricity demand, how minigrid systems can be simulated, optimised and reoptimised over time to maintain a reliable and affordable supply of electricity to the community, and how this can be expressed as a mathematical and computational framework. In chapter 7 I will apply this framework to minigrid systems in rural Uttar Pradesh to again ask what long-term cost and GHG advantages PV minigrids would have in comparison to diesel generation, hybrid systems and incumbent energy access such as kerosene for lighting, what the effect

would be of permitting minigrids to draw power from the national grid, and under what conditions would PV minigrids be superior to grid extension. Throughout this work, and in summary in chapter 8, I will ask the question of what potential PV technologies would have in mitigating GHG emissions in the cases I explore.

1.5.3 Structure of this work

This work is composed of eight chapters. This chapter has introduced this work and the body of literature surrounding it, including identifying the research gaps which it aims to fill and in chapter 2 I will present the methodology and assessment criteria used to analyse PV systems. In chapter 3 I present the potential for mature and emerging PV technologies to be used in minigrid systems in rural India and the scenarios under which they can mitigate GHGs via their deployment ahead of diesel generation or the extension of the grid network, and also the impacts of using hybrid PV and diesel minigrids. In chapter 4 I present an LCA of a new design of CPV module which aims to minimise its materials usage to maximise its potential to mitigate GHGs; this represents a fairer assessment of the potential of CPV than in the case of rural electrification, and I consider its deployment in several high-irradiance locations in which it would be well suited.

In chapter 5 I return to the issue of rural electrification and describe the results of fieldwork undertaken in rural villages in Uttar Pradesh, India, with the goal of providing data which can be directly integrated into minigrid energy systems models and that can also be used as a baseline against which to assess the potential of PV minigrids. I describe in chapter 6 a novel model for minigrid simulation and optimisation which aims to address the gaps in the literature that I have identified. I then apply this model in chapter 7 to the case of electricity access in rural Uttar Pradesh, comparing PV minigrids of various reliabilities to diesel generation, hybrid systems, grid-connected systems and incumbent energy access. This allows me to identify the scenarios in which PV minigrids can provide the greatest

benefit and to quantify their potential to mitigate GHG emissions from other sources. Finally, in chapter 8, I summarise the work that has been presented, identify the most important conclusions, and suggest areas for future research.

This work features results that have been previously published, in whole or in part, in academic journals. Where relevant, materials from this work have been appropriately acknowledged and cited and are reproduced with permission of the authors in adherence with the copyright of their respective journals. Further details of these permissions are given in appendix A.

Chapter 2

Methodology

2.1 Introduction

Analysing the value of a system relies on an understanding the most appropriate way to quantify it. In the case of PV being deployed with the goal of mitigating GHG emissions its value can be measured in many ways: it could be, for example, the amount of energy a system generates, the price that the electricity could be sold for, the GHGs that are offset through the use of renewable rather than fossil fuel power, or the cost savings to a household. Furthermore, in order to be confident in the quantification of these values, we must also be confident in our methods of representing real-life systems as theoretical simulations and in our processes for analysing them.

Here I will present the framework used for analysis in this work. This chapter serves as an introduction and overview to the methodology with each subsequent chapter also including a methodology section to further expand upon the topics discussed here and to make them specific to their analysis. In section 2.2 I present the process of life cycle analysis (LCA) which is used mainly in chapters 3, 4 and 7 to assess the environmental impact of PV energy systems. In section 2.3 I describe the mathematical notation used in this work and the treatment of functions in simulations, which are used extensively in chapter 6. In section 2.4 I present an overview of how minigrid energy systems are simulated and optimised: these processes are used in chapters 3 and 7, but as chapter 6 provides an extensive mathematical description of these processes in more detail, the description in section 2.4 is restricted to an overview to avoid later repetition. In sections 2.5 and 2.6 I present the method of calculating the financial and environmental assessment criteria for analysing PV energy systems and their suitability relative to other options, and in section 2.6 I summarise this section.

2.2 Life cycle analysis

2.2.1 Introduction

Life cycle analysis (LCA) is the method of quantifying the material and energy flows of a product, process or system. In this work I use the methodology designed by Fthenakis et al. [16] as part of the International Energy Agency Photovoltaic Power Systems Programme. These guidelines align the ISO 14040 [79] and 14044 [80] standards for LCA studies with the most relevant indicators for PV systems and provide a description of the best practice in estimating the lifetime impact of PV components and systems. LCAs typically focus on the lifetime environmental impacts of a system and this is also the case in this work, however where relevant I will also provide analogous or comparable financial assessments of the system.

I use process-based LCAs to assess systems: these account for all of the material and energy inputs at every stage of their production and the cumulative outputs over their working lifetimes to assess the overall costs and benefits of their deployment. I follow the guidelines described by Fthenakis et al. [16] as closely as possible and specify the relevant values used to parameterise the systems in order to ensure that my analysis is robust.

2.2.2 Methodology

The LCA process is composed of four stages [18, 79, 80]: defining the goal and scope, compiling the inventory of inputs into the system, assessing their impacts, and interpreting the results. The goals and scope of each LCA will vary depending on the product or system being assessed: an LCA of a PV module, for example, may focus on the material inputs and processes used in its production and account for all of the energy used in the mining materials and manufacturing which could be taken from literature databases [17, 31, 81, 82]. The LCA of a PV system, however, may combine the findings of the module LCA with those of other

components to assess the lifetime impact of the system as a whole; this allows a greater consideration of how the system performs by incorporating component-level LCAs into a larger network, rather than from fundamental materials values in an LCA database [17, 83].

The system boundaries of an LCA will affect the conclusions of each study and, for comparability between assessments, it is important to include the same components in the scope of each LCA and consistently omit those parts which are not normally considered by the literature. In line with the recommendations of Fthenakis et al. [16], I include in my LCAs the panels, mounting, balance of systems and other components necessary for the transmission of power from the point of generation to the point of use. Additionally, in the case of off-grid systems, I include the impact of battery storage, diesel generation and the national grid network where relevant. As highlighted by Fthenakis et al. [16], to avoid misguided comparisons I do not include research and development, administration, sales, commuting for workers, and other considerations that are also not included in other LCAs for PV and conventional power systems.

2.2.3 Impact assessment

Functional units

The impacts resulting from LCAs are typically reported in terms of functional units which are representative of the nature of the system; this generalises the conclusions and allows them to be compared more easily between studies. Fthenakis et al. [16] specify the kilowatt hour of electricity produced (kWh) and kilowatt-peak (kW_p) of nominal capacity as the two metrics most relevant to PV systems. Using these as a guide, in this work I also use and define further functional units which are more relevant to the applications considered: the levelised cost of electricity (LCOE) and levelised cost of used electricity (LCUE), for example, are more reflective of the value of on- and off-grid PV systems respectively and are described in more detail in section 2.5.3.

Indicators considered in this work

LCAs can assess the impact of a system using several environmental metrics [16–18] but, as the subject of this work is on the greenhouse gas mitigation potential of photovoltaic technologies, I limit the focus to the two most relevant indicators. The first is the GHG emissions of the system, which are measured in the units of the equivalent mass of carbon dioxide ($kgCO_{2eq}$) gas integrated over a 100-year time horizon [84]. The second is the cumulative energy demand (CED) of the system; this accounts for the total amount of energy consumed by the system in its creation, measured in megajoules of equivalent primary energy (MJ_{EPE}), and considers conversion losses between different types of energy.

Some of the performance indicators not considered in this work include [16, 18]: acidification potential, which measures the change in acidity of soil; ozone depletion potential, which measures the thinning of the ozone layer as a result of anthropogenic emissions; human toxicity, measuring the impact substances toxic to human health; ecotoxicity, for toxins related to natural ecosystems; resource depletion, which describes the impact on the availability of scarce resources; land and water use, which consider the consumption of available land and water supplies; and radionuclide and air-pollutant emissions, which can affect human health. Whilst these impacts are important to consider in LCA studies I choose to analyse the GHGs and CED as the most important metrics in terms of assessing the climate change mitigation potential of PV systems. Throughout this work, any reference to environmental impacts should be taken to refer to either or both of the GHGs or CED of the system rather than any of the other metrics listed above, unless specifically stated otherwise.

Interpretation of results

The results of LCAs can be further interpreted to assess the overall impact of the system. This involves combining the results with other relevant information to yield further insights: for example, the CED can be combined with the rate of energy generation of a PV system to

work out the time it takes the system to break even and produce as much energy as it took to create it [16, 85]. These interpretations can be used to analyse and understand the impact of the system in greater context and in comparison to other technological options. In this work I use a variety of analysis metrics to augment the understanding of the value or potential benefits of a system; these are described in detail in sections 2.5 and 2.6.

2.3 Mathematical notation and functions

2.3.1 Mathematical notation

The mathematical notation used in this work is described in this section. This notation was developed as part of this work to describe the mathematical and computational processes used in particular in chapter 6 in a robust and explicit format. Where possible, standard notation and formulae are used to maintain clarity and self-consistency within this work and in regards to the literature and explanations of parameters and quantities and any limitations on their numerical values, for example, are stated in the text. Subscripts and superscripts are used as labels for parameters, for example H for a specific hour of the day or M for a specific month of the year.

Parameters may be defined as values of a given kind with a specified range. For example, $D \in \mathbb{Z} : D \in [1, 365]$ means that the value of D will, in different cases, take any integer value between 1 and 365 inclusive. A parameter defined as $u_H \in [0, 1]$ means that u_H can take any value between 0 and 1 inclusive, with decimal values within that range included. The notation $\forall$ is used when a condition is true for all values, for example $u_H = 0.5 \; \forall \; H$ means that $u_H = 0.5$ for every H value considered.

A parameter can be an array of values in the form of a matrix, each element of which corresponds to the value to be used at a specific time. For example, a parameter u_{HD} could be a matrix containing the values to be used at an hour of the day H on a day of the year D

and the value $u_{15,28}$ would correspond to the value for 15.00 on the 28$^{\text{th}}$ of January. In the modelling section of this work I make use of lists of values, or matrices with dimensions $t \times 1$, to account for computational functions and this is explained in more detail in section 2.3.2. I use the notation that the minimum possible index value of t is 1.

A parameter can also represent a set of elements which are selected or cycled through. These differ from matrices in that the order of the elements does not need to be respected and often are nonnumerical or a collection of options that can be chosen. I use the symbol ξ to denote sets and to distinguish them from matrices and numerical values. For example, a set ξ_D containing the devices used in a simulation for basic energy access could be defined to be $\xi_D = \{\text{LED lights, phone charging, fan}\}$ where all of the devices are included and their order of inclusion is not important.

2.3.2 Notation and treatment of function profiles

Addition and subtraction

I define the function profile $a(t)$ to be the value of the parameter a at a point in the simulation t. To evaluate this function at a specific time point $t = \tau$ we take the τ-th element in the profile,

$$a(\tau) = a_\tau \tag{2.3.1}$$

For two functions $a(t)$ and $b(t)$ we take it that they follow the normal rules of addition and subtraction, that is if we have a function $c(t)$ given by

$$c(t) = a(t) + b(t) \tag{2.3.2}$$

then we take

$$c(\tau) = a(\tau) + b(\tau) \tag{2.3.3}$$

and equivalently, by equation eq. (2.3.1),

$$c_\tau = a_\tau + b_\tau \tag{2.3.4}$$

such that any number of functions can be summed or subtracted to provide a resultant function.

Multiplication and division

For a function $d(t)$, defined as the product of two functions, we use the Hadamard product such that

$$d(t) = a(t) \circ b(t) \tag{2.3.5}$$

denotes the element-wise product of functions $a(t)$ and $b(t)$. For the time point τ as before, this can be written in terms of the elements of the above functions as

$$d_\tau = a_\tau b_\tau \tag{2.3.6}$$

that is the multiplicative product of the τ-th elements of $a(t)$ and $b(t)$. For a function $e(t)$, which is the result of Hadamard or element-wise dividing $a(t)$ by $b(t)$, we use the notation

$$e(t) = a(t) \oslash b(t) \tag{2.3.7}$$

which, in element form for the time point τ, would be written as

$$e_\tau = \frac{a_\tau}{b_\tau} \tag{2.3.8}$$

where $b(t) \neq 0 \; \forall \; t$.

Average value of a function

The average value of a function is defined to be the average of each of the elements of the function. For a function $a(t)$ defined between two values t_1 and t_2, where $t_1 \leq t \leq t_2$, the average value of $a(t)$, $\overline{a}$, is given by

$$\overline{a} = \frac{1}{t_2 - t_1 + 1} \sum_{\tau=t_1}^{\tau=t_2} a_\tau \tag{2.3.9}$$

where we note that the denominator is a result of the way in which the elements of $a(t)$ are indexed and defined to be included in the calculation.

2.3.3 Conversions into simulation time

Overview

As the simulation and optimisation process operates in simulation time t we must convert data structures from their original formats into those of size $t \times 1$ in order to use them. This section outlines the processes behind conversions which, either on their own or via subsequent conversions, will yield an appropriate function $a(t)$ in simulation time. I use the notation $a_H \mapsto a(t)$ as shorthand for the total process of, for example, converting a profile a_H to a function $a(t)$.

Converting an hour-day profile to an hour-day-year profile

To convert an hourly profile a_H for one day of size 24×1, which is identical for every day of the year, into profile for one year a_{HD} of size 24×365 with entries for every hour of every

day of the year, we repeat the a_H as 365 columns in the new matrix:

$$a_H = \begin{bmatrix} a_0 \\ a_1 \\ \vdots \\ a_{23} \end{bmatrix} \mapsto \overbrace{\begin{bmatrix} a_H & a_H & \dots & a_H \end{bmatrix}}^{\text{Repeat 365 times}} = \begin{bmatrix} a_{0,1} & \dots & a_{0,365} \\ \vdots & \ddots & \vdots \\ a_{23,1} & \dots & a_{23,365} \end{bmatrix} = a_{HD} \tag{2.3.10}$$

where in this case a_{HD} is constant $\forall\ D$ by the nature of the original matrix a_H, but is not necessarily the case for a general matrix a_{HD}.

Converting an hour-month profile to an hour-day-year profile

To convert a profile with entries for each hour of the day of twelve representative days, one for each month of the year, a_{HM} of size 24×12 where $M \in \mathbb{Z} : M \in [1,12]$, into a profile with entries for each hour of each day of the year, a_{HD} of size 24×365, we first assume that each representative day is the middle day of that month. We generate a new matrix, a^*_{HM} of size 24×14, in which the matrix a_{HM} is placed in between two equal but nominally distinct column vectors a_{H0} and a_{H13},

$$a^*_{HM} = \begin{bmatrix} a_{H0} & a_{HM} & a_{H13} \end{bmatrix} \tag{2.3.11}$$

where a_{H0} is calculated by the equation

$$a_{H0} = \frac{1}{2}\left(a_{H1} + a_{H12}\right) \tag{2.3.12}$$

that is, the average of a_{H1} and $a_{H12}\ \forall\ H$, and that $a_{H0} = a_{H13}$.

We consider a row vector b^*_M of size, 1×14, whose first and last entries are 1 and 365, corresponding to the first and last days of the year, and whose twelve remaining ordered entries are the index number of day of the year of the middle day of each month, and where

the value of the j-th element of b^*_M is denoted by $(b^*_M)_j$. Considering each day of the year $D \in \mathbb{Z} : D \in [1,365]$, if $D = (b^*_M)_j$ for some value of j, then we can assign the j-th from a^*_{HM} to be the $(b^*_M)_j$-th column of a_{HD}.

This mapping is injective but not surjective as $\nexists\ (b^*_M)_j : D = (b^*_M)_j\ \forall\ D$, so to populate the remaining columns of a_{HD} we interpolate between two values. For a day between the middle days of two months then $D \in \left((b^*_M)_j, (b^*_M)_{(j+1)}\right)$, we linearly interpolate between the values of a^*_{Hj} and $a^*_{H(j+1)}$ in relation to the position of day D between the two middle month days. This allows us to populate a_{HD} using the conditions

$$a_{HD} = \begin{cases} a^*_{Hj} & \text{if } D \in (b^*_M)_j \\ a^*_{Hj} + \frac{D-(b^*_M)_j}{(b^*_M)_{(j+1)}-(b^*_M)_j}\left(a^*_{H(j+1)} - a^*_{Hj}\right) & \text{if } D \in \left((b^*_M)_j, (b^*_M)_{(j+1)}\right) \end{cases} \tag{2.3.13}$$

which is evaluated $\forall\ D \wedge \forall\ j$. A summary of the conversion process is

$$a_{HM} \mapsto \text{eq. (2.3.11)} \mapsto a^*_{HM} \mapsto \text{eq. (2.3.13)} \mapsto a_{HD} \tag{2.3.14}$$

This process gives a new profile a_{HD} of size 24×365 with each element corresponding to a given hour of a given day, as desired.

Converting an hour-day-year profile into simulation time

To convert a profile with entries for each hour of each day of the year, a_{HD} of size 24×365, to a yearly profile a_Y, of size 8760×1, we split the matrix into 365 day columns of size

24×1 and append each column to the one which precedes it:

$$a_{HD} = \begin{bmatrix} a_{0,1} & \dots & a_{0,365} \\ \vdots & \ddots & \vdots \\ a_{23,1} & \dots & a_{23,365} \end{bmatrix} \mapsto \begin{bmatrix} a_{0,1} \\ \vdots \\ a_{23,1} \\ a_{0,2} \\ \vdots \\ a_{23,365} \end{bmatrix} = a_Y \tag{2.3.15}$$

which gives a matrix a_Y of ordered hourly entries from the first hour of the first day of the year to the last hour of the last day of the year.

In order to convert this matrix a_Y into a time profile function $a(t)$, we append a_Y with itself $T_Y - 1$ times (for a total of T_Y a_Ys), where T_Y is the number of simulation years specified by the user,

$$a_Y = \begin{bmatrix} a_{0,1} \\ \vdots \\ a_{23,1} \\ a_{0,2} \\ \vdots \\ a_{23,365} \end{bmatrix} \mapsto \overset{\text{Repeat } Y_T \text{ times}}{\begin{bmatrix} a_Y \\ a_Y \\ \vdots \\ a_Y \end{bmatrix}} = a(t) \tag{2.3.16}$$

which will yield a column vector of size 8760 $T_Y \times 1$. We define this to be the function $a(t)$ where evaluating $a(t)$ at $t = \tau$ gives the τ-th element of the column vector, which could also be referred to as $(a(t))_\tau$ or a_τ.

2.4 Energy systems modelling for rural electrification

2.4.1 Introduction

The modelling processes used in this work rely on balancing the availability of, and demand for, energy within the system. In the case of minigrids and rural electrification this manifests itself as quantifying the energy being produced by generation sources at a given time, the energy being demanded by the community at that time, energy balancing between these two factors made possible by energy storage, and any resultant surpluses or deficits of energy. In this section I will describe the methods for calculating the amounts of energy generated by solar PV, diesel generation and the national grid network, how the degradation of battery storage is treated, and how energy demand is calculated. I will also give an overview of how minigrids are simulated, assessed and optimised; as chapter 6 describes these in more explicit detail, I will provide in this section a general outline to these processes to avoid repetition.

Throughout this work I discretise time into units of one hour, similar to other studies [60, 61, 69, 72–75, 86, 87]; this allows us to understand the overall balance of energy and the holistic performance and impacts of the energy system over a long-term timeframe without considering in explicit detail the effects of high-frequency power management and electronic engineering. Although these are important factors in the design of real-life systems, and despite the fact that it would be possible to remodel the systems described in this work at shorter time intervals if sufficiently accurate input data were available, for the more general scenarios considered in this work I take it that hourly time intervals over a 20 year time horizon to be a sufficient level of detail.

This work draws on computer programming models written in MATLAB and Python for simulating and optimising energy systems. The scripts are used to generate the results of chapters 3, 5 and 7, the last of whose modelling process is described chapter 6, are available in appendix B.

2.4.2 Energy generation

Overview

The energy systems considered in this work can have one or more generation sources: as the focus of this work, PV generation and battery storage systems are considered throughout but are also presented in comparison to other generation options such as diesel generation and the national grid network. In all cases I assess the technological performance of each energy source being used correctly and as effectively as possible and assume that there are no random failures which would limit or halt power generation, for example owing to broken PV panels, faulty wiring, or a lack of fuel for diesel generators. Energy generation is expressed as the total energy generated by each source over one timestep: this should be taken to be the number of kilowatt hours (kWh) per hour-long timestep but, owing to how the time units cancel, in certain circumstances this can also be interpreted as an equivalent average power production in kilowatts (kW) which remains constant over the time period.

Solar photovoltaics

The generation of one functional unit of solar photovoltaics, which I take to be 1 kW_p of nominal capacity, is calculated using a generic process using meteorological data and the performance of the PV module. Rather than using monthly or daily averages for insolation, I choose to use hourly data as this captures both the variability throughout the day, month and year and allows us to consider PV generation at the same resolution as energy demand, which is described in section 2.4.3. Furthermore, it allows us greater control in assessing any differences between PV technologies. This process is used in chapters 3, 6 and 7; in chapter 4 the energy yield of PV systems was calculated by Geoffrey Duggan.

Let us assume an array of panels has been installed at an elevation angle $\beta°$ and azimuth ψ °, with vertical and south-facing being defined as 90° and 180° respectively, and that the position of the sun at a point t to be at an elevation of $\alpha(t)°$ and an azimuth of $\theta(t)°$.

We assume that the PV installations are oriented to provide the maximum possible energy generation over the course of the year and that power generation from PV is curtailed only if both the community demand and the battery storage are unable to accept the generated energy. We also take it that CPV modules are installed on a tracking system which follows the movement of the sun, meaning that we consider only the direct normal irradiance and that $\beta(t) = \alpha(t)$ and $\psi(t) = \theta(t)$.

The amount of energy generated by a module will be related to the the amount of solar radiation incident upon its surface. This is calculated by inspecting several components, known as the direct normal irradiance (DNI) which arrives directly from the sun, the global horizontal irradiance (GHI) which is the amount of radiation received by a surface horizontal to the ground, and diffuse horizontal irradiance (DHI) that arrives via scattering in the atmosphere and from the ground. Each of these components will depend on the position of the sun in the sky as well as the local atmospheric and weather conditions, and hence be a function of the variable t.

The total solar irradiance on module $I_{\text{mod}}(t)$ at any time point t is given by the sum of the direct radiation from the sun, diffuse radiation from scattering in the atmosphere, and reflected radiation from the ground,

$$I_{\text{mod}}(t) = \text{DNI}(t) \circ r_{\text{DNI}}(t) + \text{DHI}(t) \circ r_{\text{DHI}}(t) + \text{GHI}(t) \circ r_{\text{GHI}}(t) \tag{2.4.1}$$

where DNI(t), DHI(t) and GHI(t) are measured or synthesised values for the location in question in units of kW per m^2 and $r_{\text{DNI}}(t)$, $r_{\text{DHI}}(t)$ and $r_{\text{GHI}}(t)$ are the respective fractions of each component incident on the module, which will depend on the orientation of the module and the sun at a given time.

The fraction of the direct or beam component of the radiation, $r_{\text{DNI}}(t)$, will depend on the relative orientations of the sun and the module as well as the air mass, a measure of the atmospheric distance through which the radiation must travel before reaching the module.

The value of $r_{\mathrm{DNI}}(t)$ is calculated using the equation [88]

$$r_{\mathrm{DNI}}(t) = r_{\mathrm{AM}}(t) \circ (sin(\beta)cos(\alpha) \circ cos(\psi - \theta) + cos(\beta)sin(\alpha)) \tag{2.4.2}$$

where α and θ remain functions of t as before but this dependence has not been included explicitly for readability. The air mass loss $r_{\mathrm{AM}}(t)$ is given by the experimentally-derived formula [89]

$$r_{\mathrm{AM}}(t) = 1.353 \left(0.7^{AM(t)^{0.678}}\right) \tag{2.4.3}$$

unless $\mathrm{AM}(t) \leq 0$, in which case $r_{\mathrm{DNI}} = 0$ as the sun is below the horizon.

The amount of diffuse radiation incident on the module as fraction of the total DHI(t), $r_{\mathrm{DHI}}(t)$, can be simplified and modelled assuming isotropic radiation from the entirety of the sky dome and calculating the proportion available to the tiled module [90]:

$$r_{\mathrm{DHI}}(t) = \left(\frac{180 - \beta}{180}\right) \ \forall \, t \tag{2.4.4}$$

which, given the module is stationary, will be constant throughout the lifetime of the installation.

A module will receive reflected radiation from the ground around it which is measured as a proportion $r_{\mathrm{GHI}}(t)$ of $\mathrm{GHI}(t)$. This depends on the elevation angle β of the module with respect to the ground and also the albedo ρ, a measure of the reflectivity of the surroundings. The amount of ground-reflected radiation is given by [91]:

$$r_{\mathrm{GHI}} = \rho \left(\frac{1 - cos(\beta)}{2}\right) \tag{2.4.5}$$

and, by combining the above equations, we reach an expression for $I_{\mathrm{mod}}(t)$. The primary irradiance data used in this work is sourced from the NREL SUNY dataset via the National

Solar Radiation Database which provides solar resource data at a resolution of 0.1° or 10 km in both latitude and longitude [92, 93].

The performance of solar photovoltaics is rated under standard test conditions, one of which is the normal operating cell temperature (NOCT), defined to be the temperature of the module under an irradiance of 0.8 kW/m^2, at an air temperature of 20°C, a wind velocity of 1 m/s and with open back side mounting. Given these conditions, the operating temperature of the cell $T_{\text{cell}}(t)$ is given by [94]

$$T_{\text{cell}}(t) = T_{\text{air}}(t) + \left(\frac{\text{NOCT - 20}}{800}\right) I_{\text{mod}}(t) \tag{2.4.6}$$

which causes the module to experience a temperature-induced deviation in performance given by

$$r_{\text{temp}}(t) = 1 + \phi_{\text{T}}(T_{\text{cell}}(t) - \text{NOCT}) \tag{2.4.7}$$

where $\phi_{\text{T}} < 0$ such that module performance is reduced for $T_{\text{cell}}(t) > \text{NOCT}$.

Over the lifetime of the module they experience a gradual and linear decline in performance compared to when they are first installed. We use the factor $\delta^{\text{PV}}(t) \in [0,1]$, where a newly installed module has a value of $\delta^{\text{PV}}(t=0) = 1$ and at the end of its lifetime has $\delta^{\text{PV}}(t = 365 \times 24 \times L_{\text{tot}}) = \delta^{\text{PV}}_{\text{min}}$ for a module lifetime L_{tot}. This degradation factor is given by

$$\delta^{\text{PV}}(t) = 1 - \frac{1 - \delta^{\text{PV}}_{\text{min}}}{365 \times 24 \times L_{\text{tot}}}\, t \tag{2.4.8}$$

where $\delta^{\text{PV}}_{\text{min}} \equiv 0.8$ [16] and the lifetime of the panels L_{tot} is typically 20 years or more.

The performance of a photovoltaic module is characterised under standard test conditions of an intensity of 1 kW/m^2, an air mass 1.5 spectrum and at a temperature of 25°C and under these conditions a module of rated capacity α^{PV} kW$_{\text{p}}$ will have a power output of α^{PV} kW. When $I_{\text{tot}}(t)$ is measured in kW/m^2, by exploiting the repetition of units we can express the

total power output of 1 kW_p of installed photovoltaic capacity as

$$F^{PV}(t) = I_{\text{tot}}(t) \circ r_{\text{temp}}(t) \circ \delta^{\text{PV}}(t) \tag{2.4.9}$$

which can provide an input into the energy system simulation. The value of $F^{PV}(t)$ is evaluated in kW/kW_p but is converted into units of W/kW_p during the simulation process and accounted for accordingly.

We note that at this point the efficiency of the modules does not factor in any of the above equations: for the purposes of calculating a power output from the rated capacity of the modules this is not an issue, but becomes one when the total area of the modules is required, for example when calculating the size and costs of mounting structures or the land area required for the installation. This is handled at various points in the modelling process where necessary and under the assumption that whatever area required by the system will be made available, unless limited by the user by capping the photovoltaic capacity at an appropriate maximum.

Diesel backup usage and sizing

In chapters 3, 6 and 7 I use diesel generation is used as a backup power supply when other energy sources are unavailable. For a blackout profile $B(t)$ and a load profile $L(t)$, I take it that the unmet energy of the community $E_{\text{un}}(t)$ is given by

$$E_{\text{un}}(t) = B(t) \circ L(t) \tag{2.4.10}$$

and $B(t)$ has the average blackout percentage $\overline{B}$ greater than the allowable threshold, B_{thr}, such that $\overline{B} > B_{\text{thr}}$ and that the diesel generator must be used to decrease the amount of time that blackouts occur. I aim to make a new blackout profile, $B_{\text{DBU}}(t)$, which is the

function describing when blackouts occur after the diesel generator has been used and satisfies $\overline{B}_{\text{DBU}} \leq B_{\text{thr}}$.

The proportion of time that the diesel generator must be used, $B_{\text{diff}} \in [0,1]$, is given by

$$B_{\text{diff}} = \overline{B} - B_{\text{thr}} \tag{2.4.11}$$

and is used to calculate the timesteps when the diesel generator is switched on. The diesel generator is optimally used when energy demand is highest as this both satisfies the needs of the community and is when the diesel generator operates most efficiently; in practice this is also when a local operator would choose to switch the generator on to meet periods of high demand. To model this I consider $E_{\text{un}}(t)$ and select a proportion B_{diff} of timesteps which correspond to the greatest values of $E_{\text{un}}(t)$. This will yield a value of $E_{\text{un}}(t)$, defined to be E_{thr}, which is the threshold above which a value of $E_{\text{un}}(t)$ is within the top proportion B_{diff} of $E_{\text{un}}(t)$. I use this to create

$$E_{\text{DBU}}(t) = \begin{cases} E_{\text{un}}(t) & \text{for } E_{\text{un}}(t) \geq E_{\text{thr}} \\ 0 & \text{for } E_{\text{un}}(t) < E_{\text{thr}} \end{cases} \tag{2.4.12}$$

which is the energy that is necessary to supply via the diesel generator in order to overcome a blackout at that time and, in doing so, achieve $\overline{B}_{\text{DBU}} \leq B_{\text{thr}}$, where $B_{\text{DBU}}(t)$ can be calculated by

$$B_{\text{DBU}}(t) = \begin{cases} 1 & \text{for } E_{\text{un}}(t) - E_{\text{DBU}}(t) > 0 \\ 0 & \text{for } E_{\text{un}}(t) - E_{\text{DBU}}(t) = 0 \end{cases} \tag{2.4.13}$$

This modelling framework implies that, for a timestep when a blackout period is recorded but a fraction of the demand was able to be provided by the system via renewables generation or battery storage, then the entirety of the demand was instead supplied by the backup diesel generator. It may be the case, for example, that the renewable generation and battery storage

need to be isolated from the diesel generator during its usage to protect their components. Whilst this may not be the case that all of the demanded energy was supplied by the diesel generator if the blackout occurred halfway, for example, through an hour-long timestep I take this to be a realistic reflection of the situation within the inherent confines of a discretised modelling framework.

In this work I use the generic algorithms described in the literature to size the diesel generation capacity and to calculate its output [61, 75, 87]. The diesel generator must be sized correctly in order to meet the blackout periods with the greatest energy requirements. A functional unit of diesel generation F^{Diesel}, for example a generator, will be capable of a maximum output $F^{\text{Diesel}}_{\text{max}}$. The required number of function units of diesel generation α^{Diesel} will be given by

$$\alpha^{\text{Diesel}} = \left\lceil \frac{E^{\text{max}}_{\text{un}}}{F^{\text{Diesel}}_{\text{max}}} \right\rceil \tag{2.4.14}$$

where the maximum amount of energy which goes unmet during the blackout period is given by $E^{\text{max}}_{\text{un}} \in E_{\text{un}}(t)$.

The total output of a functional unit of diesel generation is constrained between two values such that $F^{\text{Diesel}}(t) \in [\Gamma_{\text{min}} F^{\text{Diesel}}_{\text{max}}, F^{\text{Diesel}}_{\text{max}}] : \Gamma_{\text{min}} \in [0,1]$. This is because a generator should not be operated below a minimum fraction Γ_{min} of its total capacity to avoid operational issues and damage such as wet-knocking [95]. This means that the total output of the diesel backup generation, $V^{\text{Diesel}}(t)$, will be

$$V^{\text{Diesel}}(t) = \begin{cases} \alpha^{\text{Diesel}} F^{\text{Diesel}}(t) & \text{for } \sigma^{\text{D}}_{\text{tr}} \Gamma_{\text{min}} \alpha^{\text{Diesel}} F^{\text{Diesel}}_{\text{max}} < E_{\text{DBU}}(t) \\ \Gamma_{\text{min}} \alpha^{\text{Diesel}} F^{\text{Diesel}}_{\text{max}} & \text{for } 0 < E_{\text{DBU}}(t) \leq \sigma^{\text{D}}_{\text{tr}} \Gamma_{\text{min}} \alpha^{\text{Diesel}} F^{\text{Diesel}}_{\text{max}} \\ 0 & \text{for } E_{\text{DBU}}(t) = 0 \end{cases} \tag{2.4.15}$$

where $\sigma^{\text{D}}_{tr} \in [0,1]$ is the efficiency of transmission of energy from the diesel generation to the loads.

In systems where diesel generation is the only source of power generation we take it that the initial $B(t) = 1 \; \forall \; t$ for calculating $E_{\text{un}}(t)$ in eq. (2.4.10), as if no other sources of generation are present then blackouts must occur at all times. The same process is then followed to provide sufficient power provision to achieve $\overline{B} > B_{\text{thr}}$.

Grid power

Electricity supplied by the national grid can be used to meet the energy needs of the community in addition to, or as an alternative to, other generation sources. Electricity from the grid is treated as an inexhaustible resource and is not limited by any factor other than its availability, meaning that when the grid supply is present then the demand of the community will always be satisfied.

In chapter 3 I investigate supplying villages with grid power which is always available and therefore always meets community demand. In chapter 7, however, I use an improved model of grid availability described in section 6.2.3 to assess more lifelike situations where the grid network includes periods of downtime where electricity is not supplied. In both cases the energy supplied to the community by the grid, $E_G(t)$, which aims to meet the energy load demanded by the community, $E_L(t)$, will be given by

$$E_G(t) = G(t) \circ E_L(t) \tag{2.4.16}$$

where $G(t) = 1$ when the grid is available and $G(t) = 0$ when it is not. In chapter 3 I assume that $G(t) = 1 \; \forall \; t$ when the grid is considered as an electrification option and in chapter 7 I use the process described in section 6.2.3 to statistically model the binary availability of grid power.

Calculation of battery degradation

In chapters 3, 6 and 7 I use a model for battery lifetime which assumes that a battery system can be expected to store and provide a certain amount of energy, S_{tot}, over the course of its life. This will be specific to the battery technology, usage application and many other factors; ultimately these will be captured by the battery depth of discharge and the number of expected battery cycles, N^{cyc}, and will be specific to the chosen application. In this section I will present the generic process described in academic and industrial literature and applied to my modelling processes [69, 78, 96–98].

A battery with a rated capacity of S_r which is operated between the maximum and minimum operational capacities $S_{\max}(t)$ and $S_{\min}(t)$, suffers a degradation factor $\delta^{\text{bat}}(t) \in [0,1]$ and $\delta^{\text{bat}}_{\min}$ is the lowest proportion of battery capacity at the end of its normal recommended lifetime. The total energy throughput S_{tot} is calculated via

$$S_{\text{tot}} = N^{\text{cyc}}(\kappa_{\max} - \kappa_{\min})S_r \tag{2.4.17}$$

where usable capacity of the battery will be limited between a maximum and minimum proportion of the total capacity, $\kappa_{\max}$ and $\kappa_{\min}$ respectively, where $\kappa_{\max}, \kappa_{\min} \in [0,1] : \kappa_{\max} > \kappa_{\min}$. The total cumulative energy supplied at a point t by the batteries during their lifetime, $S_{\text{cum}}(t)$, is given by

$$S_{\text{cum}}(t) = \sum_{t=0}^{t} \Big((1 - \sigma^{\text{bat}}_{\text{leak}})S(t-1) - S(t) \Big) \tag{2.4.18}$$

for values satisfying the inequality which denotes energy flowing out of the battery

$$(1 - \sigma^{\text{bat}}_{\text{leak}})S(t-1) > S(t) \tag{2.4.19}$$

where the battery leaks a proportion of its stored energy, $\sigma^{\text{bat}}_{\text{leak}}$, during each time interval t.

We take reduction in usable battery capacity governed by $\delta^{\text{bat}}(t)$ to be related to the proportion of the total cumulative energy supplied $S_{\text{cum}}(t)$ and given by the equation

$$\delta^{\text{bat}}(t) = 1 - \left(\frac{S_{\text{cum}}(t)}{S_{\text{tot}}}\right)(1 - \delta^{\text{bat}}_{\text{min}}) \tag{2.4.20}$$

such that when $S_{\text{cum}}(t) = S_{\text{tot}}$ then $\delta^{\text{bat}}(t) = \delta^{\text{bat}}_{\text{min}}$ as expected.

This model of degradation of performance mathematically permits the consideration of battery storage operating beyond its recommended working parameters, such as when $S_{\text{cum}}(t) > S_{\text{tot}}$, which would not be recommended by battery manufacturers but is nonetheless possible to occur in rural energy systems where regular battery replacement is not undertaken. I consider this a fair representation of the potential overuse of batteries and one that can be overcome by reoptimising the energy system at appropriate time periods. This work does not consider any potential variation in performance based on manufacturing issues causing unexpected failures or deviations in performance of the batteries.

2.4.3 Energy demand

The demand for electricity services within a community results in an aggregated total demand on the energy system. In this work I identify two kinds of energy demands: the first is related to domestic household energy services such as lighting, phone charging, and basic entertainment and comfort devices such as televisions, radios and fans. The second is for productive and commercial energy services which could range from sewing machines and power tools to agricultural processing machinery. Providing domestic loads allows households to achieve the basic energy access whereas commercial loads can facilitate income generation and the economic development of the community. As the energy demands of these two types of services vary considerably then the design of an energy system would need to reflect this: in this work, therefore, I make the distinction between systems that

supply domestic loads only and those that supply both domestic and commercial energy demands. The electrical services and devices made available to the community are stated where relevant in the following chapters.

As with energy generation, the energy demand is considered as a total number of kilowatt hours demanded during one hour-long timestep as is most common in the literature [72] but, as before, it would be possible to model the systems in shorter periods if necessary. I use two methods of quantifying community energy demand: in chapter 3 I consider electricity load profiles representing the entire community for either domestic or commercial energy services. These profiles vary throughout the day and are repeated for every day of the energy system simulation but do not vary between days or over the year. Designing a system based on a repeating load profile such as this could result in a system being unable to meet higher fluctuations in demand, resulting in blackouts, but simplifies the modelling process [70, 73, 99].

In chapter 7 I use the process described in section 6.3 which builds a bottom-up demand profile [69, 70, 100] based on the number of households, the average ownership of devices, the probability of a device being used at a given time during the day, and the power of each device. To avoid repetition I refer the reader to chapter 6 for a full explanation of this process however the end result is an aggregated community-level load profile for either domestic or commercial energy services which varies both during the day, between days, seasonally and can increase over time as the community develops and has greater access to electrical devices. A similar process is also used in chapter 5. This process allows a more realistic consideration of fluctuations in energy demand which can have an impact when simulating energy systems.

2.4.4 Simulating minigrids

The topic of simulating minigrid energy systems is the subject of chapter 6, and in particular section 6.4, and so to avoid repetition I will present here an illustrative overview of the

generic algorithms for how minigrid systems are simulated [73, 74, 87, 101] and provide a full mathematical and computational description later in this work.

Let us consider the simplified case where a minigrid system has a generation capacity which supplies the system with energy, $E_{\text{gen}}(t)$ at the time t, and the community energy demand is given by $E_L(t)$. The energy difference between these two quantities, $E_{\text{diff}}(t)$, is given by

$$E_{\text{diff}}(t) = E_{\text{gen}}(t) - E_L(t) \tag{2.4.21}$$

and has two possible cases,

$$E_{\text{diff}}(t) \begin{cases} \geq 0 & \text{Load is satisfied} \\ < 0 & \text{Load is unsatisfied} \end{cases} \tag{2.4.22}$$

When $E_{\text{diff}}(t) \geq 0$ the community load is satisfied, but for $E_{\text{diff}}(t) < 0$ the energy deficit needs to be overcome. In minigrid systems this is typically done via energy storage in batteries, which can provide additional energy, $E_{\text{Bat}}(t)$, when the energy from generation is insufficient or absent entirely, for example during the night for PV. The resultant energy, $E_{\text{res}}(t)$, is the final overall balance of energy in the system after generation, load and battery storage are accounted for and is defined by

$$E_{\text{res}}(t) = E_{\text{Bat}}(t) - |E_{\text{diff}}(t)| \tag{2.4.23}$$

and has two possible cases,

$$E_{\text{res}}(t) \begin{cases} = 0 & \text{Battery meets energy deficit} \\ < 0 & \text{Shortfall occurs} \end{cases} \tag{2.4.24}$$

where we note that $E_{\text{res}}(t) > 0$ will not occur as $E_{\text{Bat}}(t)$ will be calculated to satisfy and negate any unmet load rather than exceed it. Any shortfalls are a result of when both the total generation capacity of the system and the energy supplied by battery storage are insufficient to meet the load demand and may manifest itself as a complete power outage, such as a blackout, or as a period of reduced service, where the voltage of the system may be insufficient to power devices.

This simplified description outlines the fundamental energy balances within the energy system which, as mentioned, are described in far more detail in chapter 6. This chapter also includes the treatment of the charging and discharging of battery storage, the integration of different energy generation sources including a grid network, the inclusion of transmission losses and inefficiencies, and the computational process of simulating minigrid systems. Furthermore chapter 6 also describes how a system can be analysed and assessed using performance data taken from the simulation, which is used in section 2.4.5.

2.4.5 Selecting the optimum system

Technological performance

Using the data generated from energy systems simulations I am able to assess the performance of, for example, several systems with different generation capacities that all aim to satisfy the same community demand. Metrics which analyse the performance of the system include the energy generated by each generation source, the state of charge of the battery over time, the energy surplus or deficit of the system; the methods of calculating these, and many others, are available in section 6.4.

Throughout this work I choose one metric, the blackouts experienced by the system, as the key assessment criterion for performance assessment: this is the indicator which captures the overall reliability and suitability of the system and is most reflective of its suitability in providing reliable power. A beneficiary of a minigrid may be unaware of the total energy they

consume and would have little reason to know how much energy each generation source has produced, but will be acutely aware of when electricity is unavailable at the times when it is desired. As the blackouts experienced by the system will be most evident to the community being served, providing a predictable power supply is one of the most important factors in ensuring community satisfaction [52, 102].

As described later in section 6.4, the technological performance metrics produced by the simulation process are recorded for each hour of the simulation period. This allows us to analyse, at an hourly resolution, the performance of each aspect of the system, however I choose instead to use the average performance over the duration of the simulation. Taking the average value allows a greater comparability between the systems with a variety of configurations whilst also succinctly summarising performance. Comparing hourly, seasonal or yearly performances would be possible, but would be less robust in comparing distinct systems and could potentially give the impression of a higher degree of precision in the modelling process than should be taken. Throughout this work I use the blackout percentage $\overline{B}$, the average value of the blackout profile $B(t)$, as the primary indicator of system performance. The proportion of time that energy is unavailable caused by blackout periods, and to a lesser extent the amount of energy that goes unmet as a result of blackout periods, are common criteria in assessing system performance [72, 73, 78, 87, 103]. I chose the former as it better represents the reliability of the system and its goal to provide sustainable power.

Assessment criteria and optimisation

If two systems of different configurations both have an equivalent technical performance, which in this work I take to be achieving the same level of service reliability, then further comparison in terms of the financial cost or impact upon the environmental can allow us to select which of the two should be deployed. The methods for calculating the economic or environmental impact of a system are presented in sections 2.5 and 2.6 respectively and this

selection process, both the recognition of systems which meet a threshold of technological performance and the identification of a single system which maximises or minimises a given criterion, is referred to as the optimisation of a system. A detailed mathematical description of the optimisation process is given in section 6.5.

Optimisation, in this context, is the simulation of many possible configurations of system components from which a single superior configuration is selected [58]. As the term can be used in many applications I clarify that it does not, for example, refer to the process of intervening in a currently-installed system with the goal of improving the performance via fine-tuning or corrective interventions, maximising the amount of revenue that can be generated, or increasing the profit that can be achieved.

As discussed in later chapters, I use the levelised cost of used electricity (LCUE) of a system presented in section 2.5.3 as the primary criterion in selecting the optimum system as this best captures the value of an energy system for its users. As the LCUE is an economic measure, I assume that a minigrid system is assessed first for its technological performance in supplying reliable power and then for its financial viability, which means that any environmental considerations are inherent results of the deployed system rather than parameters that are optimised for. Whilst it would be possible to optimise in such a way that would yield systems with the lowest total GHGs, for example, I chose to minimise the LCUE of the system instead as this is much more common in the design of off-grid minigrid systems [58, 72].

2.5 Financial assessment

2.5.1 Introduction

The viability of a system is often decided on whether or not its deployment can provide a financial benefit. I will assess this in a variety of ways which, in general, account for the life-

time expenditures required for the deployment and operation of the system to account for the cumulative long-term investment. Some of these, for example the net present value, are used to calculate the total costs of a system and others, for example the levelised cost of electricity, are more relevant in assessing the relative impacts of systems in comparison to their useful impact. I will also use comparative metrics, such as the grid extension breakeven distance, to assess which electrification option is more financially viable under given conditions and incorporate the cost considerations in environmental metrics in section 2.6.

2.5.2 Net present value

The net present value (NPV) of an investment measures the worth of an investment over time and can be used to decide whether a project will return a net profit or loss over a given investment period. The time value of money means that there is a greater benefit in receiving an investment sooner rather than later, and as such they are governed by an interest or discount rate: this compensates the investor and allows them to receive a favourable return in exchange for lending the money.

The NPV of an investment is the sum of each expenditure made at a given time period divided by a discount factor. For each $n \in [0, n_{\text{max}}] : n \in \mathbb{Z}$ over a total of n_{max} years, investments are made for each component $i \in \xi^n_{\text{sys}}$, where ξ^n_{sys} is the set of all investment types in year n for the given system. Each of these investments will cost C^i_n and the project will be subject to a discount rate r. The equation for the total NPV is given by [74, 85, 104, 105]

$$\text{NPV} = \sum_{n=0}^{N_{\text{max}}} \frac{1}{(1+r)^n} \left(\sum_{i \in \xi^n_{\text{sys}}} C^i_n \right) \tag{2.5.1}$$

where, in the case of an off-grid PV and storage minigrid system, it may be the case that $\xi^0_{\text{sys}} = \{\text{PV, storage, inverter, BOS, network, installation}\}$ in the initial phase of equipment deployment and $\xi^1_{\text{sys}} = \{\text{O\&M}\}$ at the end of the first year. This takes into account the

capital costs required at the beginning of the project, for example the initial investments in equipment, as well as the recurrent costs of O&M. If the system were upgraded at the end of the fifth year of the project with additional PV generation, for example, it may be that $\xi_{\text{sys}}^{5} = \{\text{PV, BOS, installation, O\&M}\}$. It is not required that $C_{n_1}^{i} = C_{n_2}^{i}$, as different amounts can be spent on the same component i for two different years n_1 and n_2.

Unless stated otherwise, any reference to costs, investments, expenditures and other financial transactions refer to discounted values over the lifetime of the system and are measured in US dollars ($). I use the NPV as the financial foundation of the analysis in this work, however owing to the variation in the sizes of systems fulfilling different requirements a simple comparison of NPVs would be inappropriate for their appraisal. For this reason I focus on a more functional measure of assessment derived from both the cost and performance of the system.

2.5.3 Levelised cost of electricity

The levelised cost of electricity (LCOE) is the most common metric used to compare the costs of different electricity sources. As power generation sources can vary significantly in terms of scale, cost, lifetime, output and other factors, the LCOE provides a unifying comparator to judge the value of different options in a quantifiable manner.

The LCOE is calculated by dividing the NPV found from section 2.5.2 by the sum of energy output by the system, which has also been equivalently discounted. The total discounted energy over the project lifetime E_{disc} is calculated from the sum of the energy from each year n, E_n, using the formula

$$E_{\text{disc}} = \sum_{n=0}^{N_{\text{max}}} \frac{E_n}{(1+r)^n} \tag{2.5.2}$$

which is used in the equation

$$\mathrm{LCOE} = \frac{\mathrm{NPV}}{E_{\mathrm{disc}}} \tag{2.5.3}$$

to give a value for the LCOE. Explicitly, this can be written as [72, 74, 75, 85, 104]

$$\mathrm{LCOE} = \frac{\sum_{n=0}^{N_{\mathrm{max}}} \frac{1}{(1+r)^n} \left(\sum_{i \in \xi_{\mathrm{sys}}^n} C_n^i \right)}{\sum_{n=0}^{N_{\mathrm{max}}} \frac{E_n}{(1+r)^n}} \tag{2.5.4}$$

by combining eqs. (2.5.1) to (2.5.3). This represents the price at which electricity should be sold to exactly offset the costs incurred by the project and, in doing so, break even. In general the owner of a project with a given LCOE will look to supply the electricity at a higher price to generate a return on their investment.

The LCOE is a common metric for grid-connected assets as it is a reasonable assumption that the entirety of the electricity generated will be used by the network of consumers. For off-grid systems, however, it is not possible to ensure that all of the generated energy will be used: generation from renewable sources, for example, may be mismatched with the times of demand and energy may need to be dumped if the loads are satisfied and the battery storage is saturated. For this reason I make the distinction between the levelised cost of electricity generated by the system (LCGE, synonymous with LCOE for grid-connected systems) and the levelised cost of the used electricity (LCUE) by the community. By accounting for only the used energy in a system we capture a greater understanding of its value to the end consumers in terms of satisfying their electricity needs [106].

By recasting eq. (2.5.2) in terms of E_n^u, the sum of energy used in year n, to give E_{disc}^u, and by following an identical process to that used to calculate LCOE, we can derive the equation

$$\mathrm{LCUE} = \frac{\sum_{n=0}^{N_{\mathrm{max}}} \frac{1}{(1+r)^n} \left(\sum_{i \in \xi_{\mathrm{sys}}^n} C_n^i \right)}{\sum_{n=0}^{N_{\mathrm{max}}} \frac{E_n^u}{(1+r)^n}} \tag{2.5.5}$$

for calculating LCUE. As shorthand I use $\mathscr{L}$ to represent the function calculating LCUE given by eq. (2.5.5), such that $\mathscr{L}(\Psi)$ is the LCUE of a system Ψ.

In this work I will use LCUE in chapters 3, 6 and 7, and LCOE for utility scale grid assets in chapter 4, which are measured in US dollars per kilowatt hour ($/kWh) as the primary criterion for the financial assessment of systems. As well as providing a fair comparison across a range of scales, technologies and applications both within this work and the literature, the levelised cost of electricity captures both the cost and performance of an energy system. Although the LCOE is more common in assessing system design I instead choose to use the LCUE optimisation criterion: off-grid systems, and in particular those supplied by PV, are vulnerable to dumping significant amounts of energy and so accounting only for the useful energy used by the community provides a better measure of the value of the system [106]. The cost of the electricity used by the community is important to system designers and operators in establishing tariffs, for example, and including the wasted energy would artificially lower the prices and result in unexpectedly low returns. When considering systems with multiple generation sources I include all of the costs and energy used in an aggregated LCUE.

2.5.4 Grid extension distance

Supplying a community with electricity can be achieved in two ways: extending the national grid network to reach the previously unconnected community and provide them with centrally generated power, or create a decentralised, off-grid system independent of the national network to provide locally-generated power. In general the cost of the power supplied by the grid network is lower than for off-grid systems, but the investment in infrastructure required to extend the grid is high [44]. At some point, therefore, it is more economically viable to provide an off-grid system rather than extend the grid: this is the breakeven distance.

The breakeven distance is calculated by considering the entire lifetime costs of the two options, an off-grid system Ψ^{OG} and a grid connected system Ψ^{G}, which we will assume

provide identical qualities of service and are optimised to the same criteria. Let us assume that the lifetime NPV of Ψ^{OG} is a function of the composition of Ψ^{OG} only, $\mathscr{C}\left(\Psi^{\mathrm{OG}}\right)$, and the lifetime NPV of Ψ^{G} is both a function of the composition of Ψ^{G} and the distance d_{ext} the grid must be extended, $\mathscr{C}\left(\Psi^{\mathrm{G}}, d_{\mathrm{ext}}\right)$. In general, it is the case that [58, 60, 105]

$$\mathscr{C}\left(\Psi^{\mathrm{OG}}\right)\begin{cases} > \mathscr{C}\left(\Psi^{\mathrm{G}}, d_{\mathrm{ext}}=0\right) & \text{adjacent to existing grid} \\ = \mathscr{C}\left(\Psi^{\mathrm{G}}, d_{\mathrm{ext}}=d_{\mathrm{ext}}^{\mathrm{br}}\right) & \text{at breakeven distance} \\ < \mathscr{C}\left(\Psi^{\mathrm{G}}, d_{\mathrm{ext}}\mapsto\infty\right) & \text{at very large distances} \end{cases} \tag{2.5.6}$$

where $d_{\mathrm{ext}}^{\mathrm{br}}$ is the breakeven distance. We take it that the $\mathscr{C}\left(\Psi^{\mathrm{G}}, d_{\mathrm{ext}}\right)$ can be split into two independent parts, $\mathscr{C}\left(\Psi^{\mathrm{G}}\right)$ and $\mathscr{C}\left(d_{\mathrm{ext}}\right)$, which correspond to the costs pertaining to the local system and the extension infrastructure respectively [44, 105],

$$\mathscr{C}\left(\Psi^{\mathrm{G}}, d_{\mathrm{ext}}\right) = \mathscr{C}\left(\Psi^{\mathrm{G}}\right) + \mathscr{C}\left(d_{\mathrm{ext}}\right) \tag{2.5.7}$$

Furthermore, I assume that $\mathscr{C}\left(d_{\mathrm{ext}}\right)$ is directly proportional to the extension distance [44, 105],

$$\mathscr{C}\left(d_{\mathrm{ext}}\right) = \mathscr{C}\left(d_{\mathrm{ext}}^{\mathrm{unit}}\right) d_{\mathrm{ext}} \tag{2.5.8}$$

where $\mathscr{C}\left(d_{\mathrm{ext}}^{\mathrm{unit}}\right)$ is the cost of extending the grid by a single unit of distance, considered to be one kilometre (km). By rearranging eq. (2.5.6) and using eqs. (2.5.7) and (2.5.8) we can calculate the grid extension distance,

$$d_{\mathrm{ext}}^{\mathrm{br}} = \frac{\mathscr{C}\left(\Psi^{\mathrm{OG}}\right) - \mathscr{C}\left(\Psi^{\mathrm{G}}\right)}{\mathscr{C}\left(d_{\mathrm{ext}}^{\mathrm{unit}}\right)} \tag{2.5.9}$$

above which it is more economical to provide an off-grid system rather than one with a grid connection.

For a village which would require d_{ext} km of grid extension to be connected, I choose an electrification strategy such that

$$d_{\text{ext}} \begin{cases} < d_{\text{ext}}^{\text{br}} & \text{extend the grid network} \\ = d_{\text{ext}}^{\text{br}} & \text{use either option} \\ > d_{\text{ext}}^{\text{br}} & \text{use an off-grid system} \end{cases} \tag{2.5.10}$$

where, if $d_{\text{ext}} = d_{\text{ext}}^{\text{br}}$, other factors will be used to decide the strategy. This can be used as a decision-making criterion to assess which option a given community should be provided with, which I use in chapters 3, 6 and 7.

The viability of grid extension will depend on several factors, including the cost of on- and off-grid systems, the extension distance required, and the topology of the local terrain [44]. The reliability of the grid electricity will also impact the breakeven distance; in this section I do not make a distinction between grid-connected systems that do and do not rely on minigrid backups to ensure an adequate supply as the total local system costs are encapsulated in the definition of $\mathscr{C}\left(\Psi^{\text{G}}\right)$. Analogous metrics for assessing the viability of grid extension, in particular with respect to environmental assessments, undergo a similar process to calculate grid breakeven distances but use embedded GHGs, emissions intensities, or the marginal abatement cost as the determining factor instead of the NPV.

2.6 Environment assessment

2.6.1 Introduction

In an analogous way to the lifetime expenditure of the system I also use LCA to account for its environmental impact. To do this I focus the two key areas most relevant to climate change mitigation: the embedded energy and embedded GHGs. In this work I refer to environmental

impact in regard to these two parameters and not, for example, environmental indicators such as toxicity, the consumption of scarce resources, or land use. Similar to the financial analysis the environmental impact is assessed both in terms of the lifetime total, for example the cumulative energy demand, and in terms of the impact for unit output of the system, such as the emissions intensity. The marginal abatement cost, in section 2.6.5, and introduction of carbon pricing, in section 2.6.6, integrate both financial and environmental impacts to assess the conditions under which a more expensive system with lower GHG emissions may be considered viable.

2.6.2 Cumulative energy demand and embedded GHGs

The cumulative energy demand (CED) of a system, also known as the embedded or embodied energy, is the total amount of primary energy needed to create it [16, 85]. This includes, for example, the energy used in mining raw materials, manufacturing processes for making components, shipping from factories to the deployment location and end-of-life management. The CED is measured in terms of equivalent amount of primary energy, typically expressed in megajoules ($\mathrm{MJ_{EPE}}$), which takes into account the inefficiencies of converting energy from one form to another during the production process. The CED of a system Ψ, $\mathscr{E}(\Psi)$, with components $i \in \xi^n_{\mathrm{sys}}$ installed in each year n, is given by [107]

$$\mathscr{E}(\Psi) = \sum_{n=0}^{N_{\max}} \sum_{i \in \xi^n_{\mathrm{sys}}} E^i_{\mathrm{EPE}} \tag{2.6.1}$$

where E^i_{EPE} is the embedded primary energy of each component i. The embedded energy of each component will depend on the embedded energy of its subcomponents, for example the materials and processed used to produce it. I use this metric in particular in chapter 4.

An analogous measure is the cumulative embedded (or embodied) GHG emissions of a system. Similarly to the CED, the embedded GHGs measures the total emissions associated

with the production of the system. This metric is calculated in terms of the equivalent global warming potential of the various gases released over a 100-year time horizon relative to one kilogram of carbon dioxide ($kgCO_{2eq}$) [84]. Equivalently to eq. (2.6.1), the cumulative embedded GHGs of a system Ψ, $\mathscr{G}(\Psi)$, is given by

$$\mathscr{G}(\Psi) = \sum_{n=0}^{N_{\max}} \sum_{i \in \xi_{\text{sys}}^{n}} G^{i} \tag{2.6.2}$$

where, as before, G^i is the embedded GHGs of component i and will depend on the embedded GHGs of its constituent subcomponents. I use this metric in chapters 3 to 7.

The calculation of CED and embedded GHGs is dependent on the boundaries of the system, with the most comprehensive analyses "from the cradle to the grave", meaning including all materials and processes from the acquisition of raw materials to the decommissioning of the system and including the entire lifetime of the system [16]. Other boundaries could be drawn at the end of the manufacturing process but before deployment ("cradle to gate") which can be used to assess the viability of different options agnostic of their end usage. In this work I analyse systems over their entire lifetime unless otherwise specified.

2.6.3 Energy and carbon payback times

The energy payback time (EPBT) is used to measure the time taken for a deployed system to repay the energy used to create it, with a smaller EPBT preferential to a greater one, and providing a breakeven point for the system. The EPBT of a system Ψ is given by [16, 85, 107]

$$\text{EPBT} = \frac{\mathscr{E}(\Psi)}{\frac{E^{\text{gen}}}{\eta_{\text{grid}}^{\text{EPE}}} - E^{\text{O\&M}}} \tag{2.6.3}$$

where E^{gen} is the annual energy generation of the system, $\eta_{\text{grid}}^{\text{EPE}}$ is the conversion efficiency of the grid network from primary energy to electrical energy, and $E^{\text{O\&M}}$ is the annual energy required for operation and maintenance of the system, which I take to be self-generated.

The equivalent metric for GHG emissions is the CO_{2eq} payback time (CPBT) which measures the time taken for a system to offset the GHGs used in its production. This is founded on the principle that low-carbon electricity, such as that generated by PV systems, replaces higher-carbon electricity from the local grid network that would have otherwise been used. The CPBT of a system Ψ is given by

$$\text{CPBT} = \frac{\mathscr{G}(\Psi)}{(E^{\text{gen}} - E^{\text{O\&M}})\,\eta_{\text{grid}}^{\text{C}}} \tag{2.6.4}$$

where $\eta_{\text{grid}}^{\text{C}}$ is the emissions intensity of the local grid network.

The EPBT and CPBT, both measured in years, give us assessment criteria for systems in terms of the time taken to provide a net-positive effect on the environment. This can be used as a fair comparison between systems composed of different technologies or deployed in different locations, as I do in chapter 4. It is possible to calculate an environmental return on investment by dividing the expected system lifetime by the EPBT or CPBT; I refrain from doing this, however, as it is strongly dependent on an accurate estimation of the lifetime which may not be possible owing to the novelty of the systems proposed. The EPBT and CBPT provide a more robust comparison as, in this work, they are much shorter than the expected lifetime of the systems.

2.6.4 Emissions intensity

The emissions intensity, also referred to as the specific emissions, of an electricity source expresses the amount of GHGs released per kWh (gCO_{2eq}/kWh) of electricity supplied by

the system. This is a commonly used metric to compare the GHG emissions of various different power sources or the average of the grid network as a whole.

The emissions intensity of a system Ψ, $\overline{\mathscr{G}}(\Psi)$ is given by [85]

$$\overline{\mathscr{G}}(\Psi) = \begin{cases} \frac{\mathscr{G}(\Psi)}{\sum_{n=0}^{N\max}\left(E_n^{\text{gen}} - E_n^{\text{O\&M}}\right)} & \text{for systems supplying grid network} \\ \frac{\mathscr{G}(\Psi)}{\sum_{n=0}^{N\max}\left(E_n^{\text{u}}\right)} & \text{for decentralised systems} \end{cases} \tag{2.6.5}$$

where the distinction between the cases is analogous to the difference between LCOE and LCUE. This metric is particularly useful as it captures the environmental impact of the system in the context of its overall energy output and I use it in chapters 3, 4, 6 and 7. Furthermore, the emissions intensities of electricity sources and national grid networks are well- and widely-reported [108] which allows for accurate assessments of the usefulness of a system deployed in a given area. Where appropriate, I compare for context the emissions intensity of systems to those of the national grid network.

2.6.5 Marginal abatement cost

The marginal abatement cost (MAC) is a comparative measure between two options, typically one with a higher cost and lower emissions, for example a renewables-based system Ψ^R, and one with a lower cost and higher emissions, for example a fossil fuel generation source Ψ^F. By comparing the differences between the two, the MAC gives a measure of the financial cost incurred by mitigating the emissions through the use of the lower-GHG option. The MAC of installing Ψ^R instead of Ψ^F, $\mathscr{M}\left(\Psi^R, \Psi^F\right)$, is given by dividing the difference in costs by the difference in GHG emissions [109],

$$\mathscr{M}\left(\Psi^R, \Psi^F\right) = \frac{\mathscr{C}\left(\Psi^R\right) - \mathscr{C}\left(\Psi^F\right)}{\mathscr{G}\left(\Psi^F\right) - \mathscr{G}\left(\Psi^R\right)} \tag{2.6.6}$$

and is measured in terms of the financial cost per tonne of CO_{2eq} abated ($/t$CO_{2eq}$). This value can be interpreted in a number of ways, with the two used in this work being that a lower MAC can offset GHG emissions at a lower cost than a higher MAC, and that $\mathscr{M}\left(\Psi^R, \Psi^F\right) < 0$ means Ψ^R will provide electricity at both at a lower cost and with lower GHGs than Ψ^F over their lifetimes. I use this to assess systems in chapter 3.

2.6.6 Impact of carbon prices

The use of carbon prices, assigning a financial cost to each tonne of emitted GHGs ($/t$CO_{2eq}$), has been suggested as an opportunity to account for the externalities of low-cost, high-GHG power sources and to make low-carbon generation more competitive in comparison. I use carbon prices as an informative measure of potential future policies which might introduce them to assess what impact, if any, they would have on the systems discussed in this work. To do this I either assign suggested future carbon prices [110] or calculate the price at which some transition would occur to affect a decision-making process. I investigate the impact of carbon prices in particular in chapters 4 and 7.

The carbon price is used as a proxy for any introduced policy that would inflate the cost of GHG-intensive sources compared to low-carbon options. This could include, for example, reducing subsidies on fossil fuels which would have the effect of increasing their prices without explicitly assigning a cost to their GHG emissions. The quantification of policy changes in terms of an equivalent carbon price is beyond the scope of this work and instead I assess what the potential implications of certain carbon prices would be for the systems considered.

2.7 Summary

The aim of this chapter has been to outline and justify the key methodological processes used for analysis in this work. As mentioned previously, these processes are elaborated upon in the following chapters with greater specificity to their individual content. In section 2.2 I outlined the processes for life cycle analysis, how the environmental impact of a system or product is assessed, and the indicators I have chosen to use and not to use. In section 2.3 I describe how the mathematical functions used throughout the work and how to convert between input data and functions compatible with the simulation of energy systems, which was discussed in section 2.4. In that section I presented how energy generation from PV, diesel generators and the grid is treated, as well as how battery storage degradation is considered. I also presented an outline of how minigrids are simulated, assessed and optimised, with these topics discussed in more detail in chapter 6.

In sections 2.5 and 2.6 I described the financial and environmental metrics used in this work to assess the impact of energy systems. These can be summarised into three types of assessment: those which assess the cumulative lifetime impact of a system; those which assess the relative performance of the systems compared to a reference unit; and those which provide a comparison between two different options to suggest which would be more suitable. These are summarised in table 2.1.

In the following chapters I will use a variety of the methodologies and criteria described here to quantify the costs and benefits of PV technologies and systems in order to analyse their potential to mitigate GHG emissions.

Table 2.1 Cumulative, performance and comparative system assessment criteria used in this work.

System assessment criteria	Acronym	Units	Financial	Environmental
Cumulative				
Net present value	NPV	$	✓	✗
Cumulative energy demand	CED	MJ_{EPE}	✗	✓
Embedded GHGs	–	$kgCO_{2eq}$	✗	✓
Performance				
Levelised cost of electricity	LCOE	$/kWh	✓	✗
Emissions intensity	–	gCO_{2eq}/kWh	✗	✓
Energy payback time	EPBT	year	✗	✓
Carbon payback time	CPBT	year	✗	✓
Comparative				
Grid extension distance	–	km	✓	✓
Marginal abatement cost	MAC	$/$tCO_{2eq}$	✓	✓

Chapter 3

PV technologies for rural electrification in India

Acknowledgement of contributions

NLA Chan designed the computer model in Python, provided data, suggested locations, and performed calculations for financial and environmental impact. S Foster researched battery technologies and produced an initial report on the study. D Nagpal designed the earlier analysis tool in Excel and gathered data relevant to its application in India. CJM Emmott provided data for OPV technologies and comments for their application. SJ Buckle suggested the study of diesel backup generation as a comparison. A Gambhir, C Candelise, N Ekins-Daukes and J Nelson advised on the direction of research and supervised the work. P Sandwell further developed, tested and validated the Python computer model, updated the cost and environmental impact data, performed simulations and analysis used in the final publication, produced the figures, and wrote the manuscript for publication.

Previous presentation of this work

This work has been published as an article in *Solar Energy Materials & Solar Cells* [111]: **Sandwell P**, Chan NLA, Foster S, Nagpal D, Emmott CJM, Candelise C, Buckle SJ, Ekins-Daukes N, Gambhir A and Nelson, J. Off-grid solar photovoltaic systems for rural electrification and emissions mitigation in India. *Sol. Energy Mater. Sol. Cells*. 2016; **156**: 147-156. DOI: 10.1016/j.solmat.2016.04.030. Work from this article is reproduced with permission [112].

Sections of this work were presented as an oral presentation:
Sandwell P, Chan NLA, Foster S, Nagpal D, Emmott CJM, Candelise C, Buckle SJ, Ekins-Daukes N, Gambhir A and Nelson, J. Off-grid solar photovoltaic systems for rural electrification and emissions mitigation in India. *Social Research on Off-Grid Solar*, University College London, UK, 9–10 December 2015.

Sections of this work were presented as a poster presentation:
Sandwell P, Chan NLA, Foster S, Nagpal D, Emmott CJM, Candelise C, Buckle SJ, Ekins-Daukes N, Gambhir A and Nelson, J. Increasing the emissions mitigation potential of off-grid solar photovoltaic systems for rural electrification. *29th European Photovoltaic Solar Energy Conference and Exhibition*, Amsterdam, the Netherlands, 22–26 September 2014.

3.1 Introduction

3.1.1 Overview

Countries with ambitions to increase the electrification rates whilst meeting national and international GHG emissions targets need to consider a variety of potential development pathways and their implications [36]. Developed nations have committed significant resources to grid infrastructure and as a result have been locked in to conventional, typically high carbon, power sources. Developing countries, however, have the opportunity to take advantage of technological developments in selecting the most appropriate means of supplying their populations with power. In regions without an existing connection to the grid, this could mean either extending the network to reach the community or providing an off-grid system.

A connection to the national grid is an aspiration for many rural communities in India but requires a significant investment in infrastructure and can suffer poor service reliability [44, 45, 52]. Diesel generators are common in villages without grid access as they can provide electricity at a relatively low cost but have high GHG emissions [113, 114], and as a result there has been increasing interest in renewable generation as a source of off-grid power. With an abundant solar resource available throughout India, PV has been presented as a viable alternative to diesel generators in remote and rural settings.

Historically high costs of crystalline silicon (c-Si) PV stimulated research into alternative technologies: those with lower production costs, such as thin film cadmium telluride modules [115]; those that can be manufactured using new and innovative processes, such as organic photovoltaics (OPV) [32]; and those which use the highest efficiency cells available in concentrating photovoltaic (CPV) systems [25]. The cost of c-Si has decreased dramatically [116] but these other technologies remain relevant if they can outperform the market leader in terms of lifetime cost, environmental impact or suitability in a given situation: in this chapter we explore the potential of these technologies in the context of rural electrification.

An overview of this chapter is given in fig. 3.1. In section 3.1 I provide a summary of the literature of PV technologies and modelling of off-grid systems to put the work of this chapter in context. In section 3.2 I give details of the community and locations I consider and the performance and impacts of the PV technologies, battery storage, diesel generation and grid extension options I investigate. I also describe the simulation and optimisation processes used to select the optimum system. In section 3.3 I assess the electrification options in terms of their financial and environmental impacts and the effects of different types of demand. I then compare a representative system to grid-connected systems to calculate breakeven extension distances. I also present the implications of combining PV, battery storage and diesel generation into hybrid systems and the impact of changing diesel and storage prices on the optimal hybrid system configuration. Finally, in section 3.4, I summarise the findings and determine the potential of different PV technologies for rural electrification.

3.1.2 Assessment criteria

In this chapter I analyse the financial and environmental impact of using PV, diesel generators and grid extension electrification options in meeting the needs of a rural community, with details of the scenario under investigation given in section 3.2.

The metric I choose for assessing the technological performance of a system is the average blackout percentage, $\overline{B}$, which is defined to be the proportion of time that power is demanded by the community but unable to be supplied by the system. A completely reliable system with no loss of service would have $\overline{B} = 0$. The blackout percentage is used as the criterion to define whether or not a system is sufficiently reliable to be eligible for consideration for deployment.

I use the levelised cost of used electricity, LCUE or $\mathscr{L}$, as the primary assessment of the financial viability of the systems. This differs from the levelised cost of generated electricity, LCGE, as it accounts for only the power used by the community and therefore a better

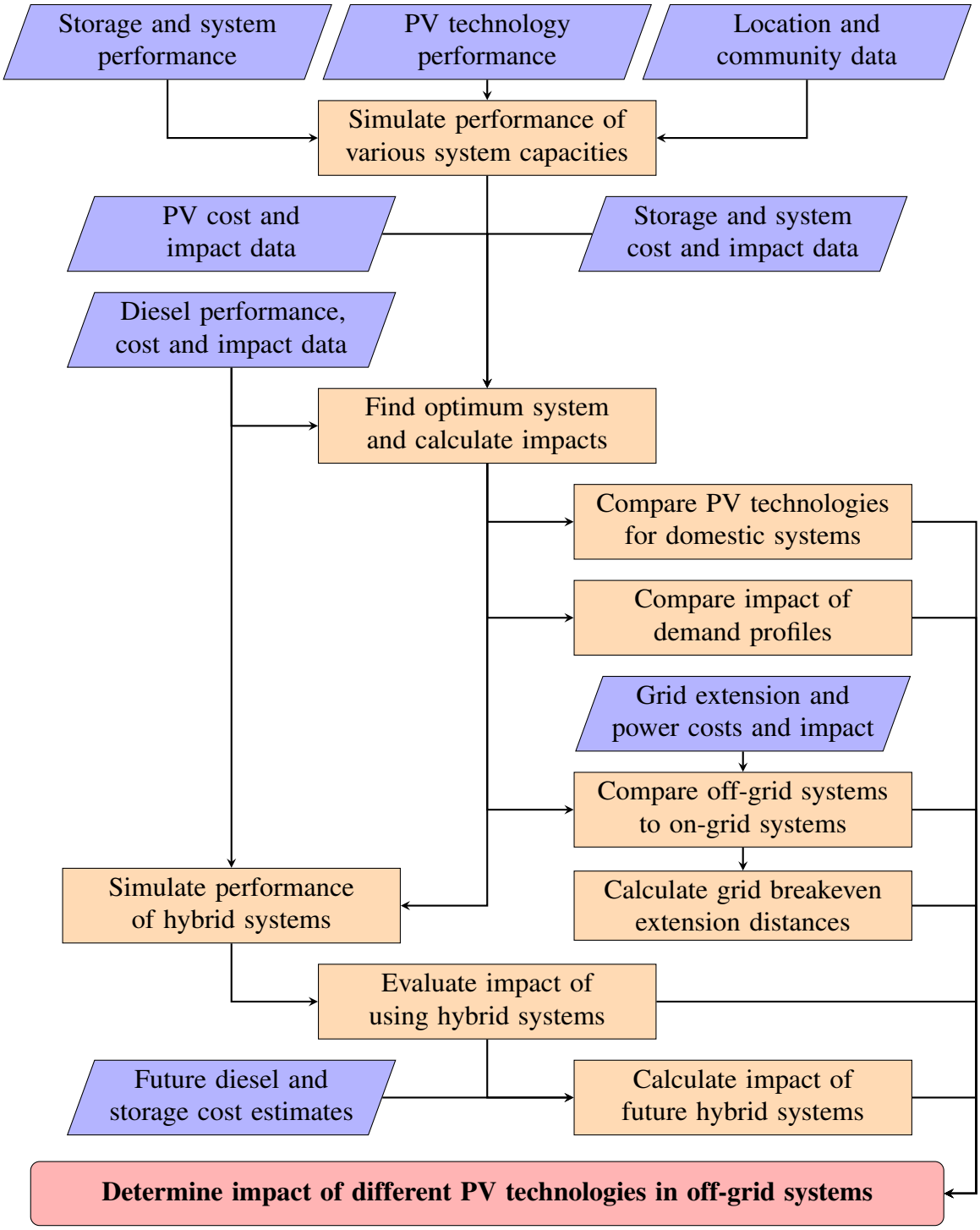


Fig. 3.1 Graphical overview of chapter 3.

measure of the value of the system. If all of the power generated by the system could be used or exported to the grid network, for example, then the LCUE and LCGE would be the same and typically this would be referred to as the levelised cost of electricity, LCOE. To distinguish between these I will specify which cost of electricity is being considered. Each of these metrics are measured in US dollars per kWh of electricity, $/kWh, with the equations used to calculated them given in section 2.5.3. The LCUE is used in the optimisation process to select the optimum system.

The cost of electricity is a widely-reported comparison criterion for electricity systems and whilst the LCUE provides an improved measure of the cost of electricity in a system where blackout periods may occur, as described in section 2.5.3, this does not account for all potential financial judgments. The value of the electricity from the point of view of the consumers, in this case the rural community, may be vary dependent on a number of factors: time at which the electricity is provided, for example being more valuable at night for lighting; the electricity service being provided, for example entertainment services may be valued higher than basic lighting or commercial electricity may be more valuable than that for households; the reliability of service, for example a supply with scheduled blackouts may be more valuable than one with random blackouts; and the incremental value of the duration of service, for example one additional hour of supply would be more valuable to a household receiving four hours per day compared to eighteen. Furthermore, the weighting of these relative values are likely to vary between households in a community and between members of a household.

Assessing these values is critical in developing a viable and sustainable delivery model and would involve, for example, securing a minimum reliability of service and assigning different prices to various energy services. This assessment will specific to the organisation providing the energy system, the community receiving it, and dependent on other external factors such as government policies. For these reasons in this chapter and beyond I choose

instead to focus on the costs of delivering the electricity services given a minimum threshold of quality of service, the LCUE and blackout percentage respectively, to appraise the minigrid systems in a similar way to other studies in the literature and without greater assessment of the perceived value of those services by the community. Understanding this value perception and the viability of potential business models is important in determining the long-term potential of the electricity system but is beyond the scope of my analysis.

To assess the environmental impact of the systems I consider the embedded GHGs in terms of their total global warming potential over a 100-year time horizon [16]. For comparability between systems supplied by PV, diesel and grid electricity I use the specific emissions of the electricity used by the community, also referred to as the emissions intensity, which is measured in grammes of CO_{2eq} per kWh of electricity used or gCO_{2eq}/kWh. This is calculated using the process given in section 2.6.4.

The marginal abatement cost, or MAC, is a comparative measure typically between one option with a high cost and low emissions and one with the opposite. I use the MAC to assess the financial cost of choosing an option with a lower environmental impact in terms of its US dollar cost per tonne of CO_{2eq} emissions that are avoided, or $\$/tCO_{2eq}$. This is used to compare PV systems to those supplied by diesel generators or the grid and is calculated using the process in section 2.6.5.

Finally, I use the grid extension distance to compare regions where on- or off-grid systems would be more suitable. This metric, measured in kilometres, gives the distance from existing grid infrastructure at which it is more effective to provide electricity via an off-grid system rather than extend the grid network to the community. I use the calculations from section 2.5.4 to assess the breakeven distance in terms of LCUE, specific emissions, and MAC.

3.1.3 Literature summary

The performance of PV technologies has been widely investigated [117] and this includes their applications to rural electrification. The majority of this research relates to the performance and cost of electricity of off-grid PV systems in comparison to the national grid network [118], solar home systems [119, 120], other off-grid power sources [106, 121] or a combination thereof [44, 59, 122]. Nouni et al. [44], for example, provide a detailed analysis of and comparison to grid extension for rural electrification whilst others, such as Chaurey and Kandpal [119], compare the financial viability of household- and village-scale PV systems in providing similar levels of electricity service. The application of optimisation models for hybrid energy systems, such as those discussed by Ashok [121] and Sen and Bhattacharyya [59], investigates the potential of combining PV with other technologies to reduce the cost and environmental impact of the off-grid system. A smaller number of studies also calculate the GHGs associated with rural electrification in the context of sustainable development [59, 106, 118, 119, 123, 124].

Emerging PV technologies have been the subject of many life cycle analyses (LCAs) but none of these had previously been assessed in their ability to provide power to rural communities. LCA studies on mature technologies, such as c-Si and CdTe, are founded on well-established and commercial-scale production data, such as those presented by de Wild-Scholten [17]. Others, for example the analysis of CPV systems by Peharz and Dimroth [25], rely on data drawn from a smaller number of deployed systems. For an emerging technology such as OPV the ultimate costs and embedded emissions of the technology will not be known until manufacturing scale-up has been achieved. Studies such as Espinosa et al. [31], therefore, estimate the future impact of the technology by extrapolating from established costs and performance and by applying realistic estimates of near-term production capabilities, for example roll-to-roll processing.

In this chapter I integrate the performance, costs and environmental impacts of mature and emerging PV technologies to assess their suitability in off-grid systems. By using techniques and assessment criteria similar to those in the literature I present an analysis of the potential impacts of different types of PV technologies, both in comparison to one another and to other electrification options.

3.2 Modelling minigrid systems in rural India

3.2.1 Scenario

System description

In this section I consider the deployment of an off-grid minigrid serving the needs of a community in rural India that previously had no access to electricity. The system is composed of a PV array, battery storage, balance of systems such as charge controllers and inverters, and a low-voltage distribution network that supplies the village with power. The village is taken to have 500 inhabitants who, cumulatively, exhibit one of the two power demand profiles given in fig. 3.2. I investigate two possible scenarios: supplying the community with lighting and basic services such as phone charging, and providing a greater amount of power to allow commercial and industrial activity. These were suggested for use in this analysis by participants of a discussion workshop held at the Indian Institute of Science, Bangalore in 2013 and implemented by Alvin Chan and Samuel Foster. The domestic services considered here are reflective of the basic needs of many communities in rural India, as I will show in chapter 5, but these can be modelled in greater detail using primary data, as I demonstrate in chapters 6 and 7.

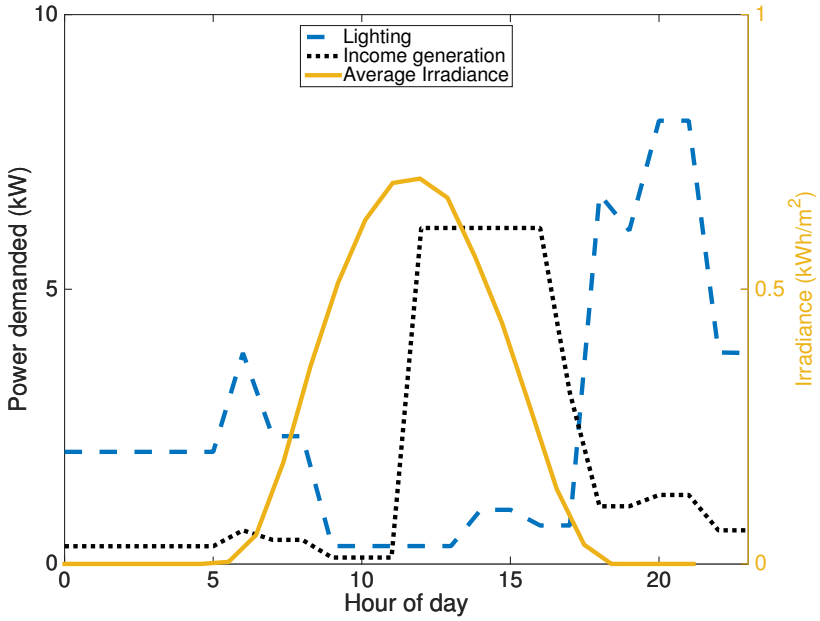


Fig. 3.2 The demand profiles used for basic domestic services (blue dashed line) and income generating activities (black dotted line) and the average hourly irradiance (yellow solid line). From Sandwell et al. [111].

Locations

I consider three locations for the deployment of the off-grid systems: in the region of Ladakh, in Jammu and Kashmir, in Barmer District, Rajasthan, and in Dhemaji District, Assam. These three locations are shown in fig. 3.3 and are representative of three remote and geographically diverse regions in which off-grid PV systems could offer a viable method of electrification. Ladakh, in particular, would likely be suitable for off-grid systems as its relatively high levels of irradiance favour the use of PV and the inaccessible terrain discourages grid extension in its remote regions. A summary of their characteristics is shown in table 3.1 and a typical average irradiance profile for Ladakh is shown in fig. 3.2.

Table 3.1 Summary of the deployment locations considered.

Location	State	Terrain type	Average GHI (kWh/m^2/day)
Ladakh	Jammu and Kashmir	Mountainous	5.51
Barmer	Rajasthan	Plains	5.88
Dhemaji	Assam	Hilly	4.41

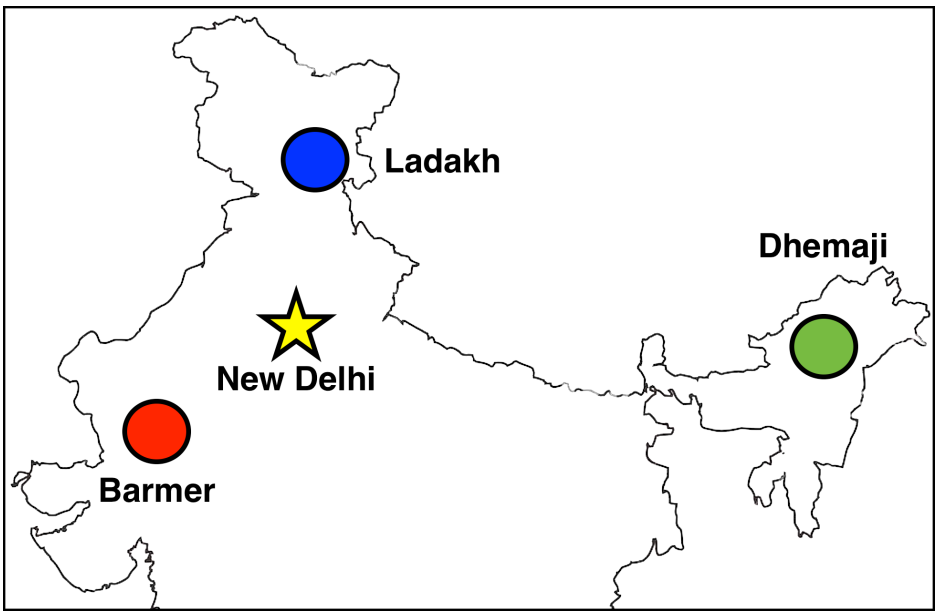


Fig. 3.3 The locations in India considered in this chapter: Ladakh (blue), Barmer (red) and Dhemaji (green), and the capital New Delhi (gold star). From Sandwell et al. [111].

3.2.2 Technologies considered

PV technologies

I assess the opportunities of four kinds of PV technologies to provide energy to the off-grid system. Two of these, monocrystalline silicon (c-Si) and cadmium telluride (CdTe), have reached technical maturity and are considered to be practical and readily-deployable as a dependable energy source. I also assess the potential for emerging technologies to provide power: concentrator photovoltaics (CPV) and organic photovoltaics (OPV), both of which are yet to reach maturity. This analysis will help identify, at an early stage, whether these PV technologies would be able to represent a feasible option based on the expectations of their development. The costs, impacts and performances of the PV technologies are reflective of their status in 2015 when this work was undertaken; naturally, values taken from studies in the literature will be from before this date.

CPV has been installed in a number of locations around the world in commercial, utility-scale settings [12, 116, 125] but not in minigrid systems for rural electrification. This PV technology is comparatively sensitive to the clearness of the sky and, typically, would be deployed in locations where high-quality irradiance data exists to ensure the optimum performance of the CPV system. It is unlikely that the rural remote regions considered here would have access to such data and so the generation data for CPV, and hence the system performance parameters, must be treated with appropriate caution. Furthermore the reliance of CPV on precise optical systems would likely require greater technical expertise than other PV technologies during installation and for maintenance. I have reflected this in the costs considered in my analysis but this also relies on the system being securely transported to and installed in a remote location, and that the suitably trained technicians are available for its maintenance. I present the analysis for CPV technologies as an initial feasibility study and, whilst these assumptions could be considered in more detail if CPV were found to be sufficiently superior to other technologies, I will show later that this is not the case.

Less data exists for OPV installations. It is suggested that the roll-to-roll production of OPV [32] could dramatically reduce the cost and embedded energy of the technology [8, 9, 31], and for this reason I consider two possible cases: one based on examples of present technology used in large pilot-scale installations [126] and in demonstrations in rural areas of developing countries [127], and one based on the potential future characteristics. The former case, "OPV (Today)", is a reflection of the technology deployable in 2015 when the study was undertaken and the latter, "OPV (Future)", is a case of what may be possible using predictions of the lifetimes and efficiencies of commercially viable modules in the long-term. These predictions for lifetime and efficiency are based on academic estimates for the future performance of OPV technology that, at present, have not yet been achieved at scale and are not yet commercially available. As for CPV, I present the case of OPV as a study of the technology if it were to become commercially viable and to explore any potential benefits in comparison to mature PV technologies. As OPV technology develops it may be necessary to repeat the "OPV (Future)" case to reassess its viability using yet-to-be-demonstrated performance characteristics and costs.

Both cases of OPV are assumed to be produced using ITO-free roll-to-roll production methods to minimise their cost and environmental impact [31]. For comparability, the costs of materials and labour for installation and balance of systems are assumed to be the same as for mature technologies, although innovative mounting structures which could reduce these costs may be viable for OPV modules in the future [126].

An overview of the performance, costs and embedded energies of the PV technologies I consider in this study is given in table 3.2.

Table 3.2 The performance, costs and embedded energy of the PV technologies considered in this assessment. *: including tracker cost. Adapted from Sandwell et al. [111].

	c-Si	CPV	OPV		CdTe
			Today	Future	
Performance					
Cell efficiency (%)	16.0 [17]	30.0 [125]	2.0 [31, 126]	7.0 [128]	11.9 [17]
Degradation (% p.a.)	1.0	0.5	4.0	2.0	1.0
Cost ($/$W_p$)					
Module	0.89 [129]	1.60* [125]	1.40 [8]	0.15 [8, 9]	0.75 [130]
Installation	0.51 [129]	0.77 [125]	0.51 [129]	0.51 [129]	0.51 [129]
Energy meter			0.04 [129]		
Inverter			0.55 [129]		
Charge controller			0.21 [129]		
Total	2.20	3.17	2.71	1.46	2.06
O&M (% p.a.)	0.5	2.0	0.5	0.5	0.5
Embedded energy (MJ_{EPE}/W_p)					
Cell (electrical)	10.74 [17]	1.30 [25]	2.03 [31]	0.33 [31]	– [17]
Cell (thermal)	16.63 [17]	1.91 [25]	1.94 [31]	0.31 [31]	6.26 [17]
Array support	0.82 [17]	8.03 [25]	– [17]	– [17]	– [17]
Frame	1.01 [17]		8.90 [17]	2.54 [17]	1.49 [17]
Cables & interconnection	0.08 [17]	0.80 [25]	0.11 [17]	0.11 [17]	0.11 [17]
Inverter	2.29 [17]		2.29 [17]	2.29 [17]	2.29 [17]
O&M	0.8 [131]	0.09 [131]	0.09 [131]	0.09 [131]	0.09 [131]
Total	31.97	12.18	15.60	5.91	10.48

Battery technology

Lead acid (PbA) batteries have been the dominant storage technology for rural electrification in the past but lithium-ion (Li-ion) storage has become increasingly prevalent. Minigrid systems with Li-ion storage have been deployed in India since 2014 [132], as well as in other developing countries [133, 134], and Bhattacharyya and Palit [135] believe that, if the costs of the technology decrease, Li-ion storage will become the preferred technology for rural minigrid systems.

Expert elicitations of off-grid energy companies operating in India and Africa by Few et al. [136] found that the higher cycle life and discharge rates of the latter, combined with significant cost and performance improvements in recent years [137, 138], has led to the two technologies dominating the off-grid market for all but the largest electricity systems. Few et al. [136] also found that community-scale minigrids with Li-ion batteries have already been deployed in developing countries and reported an increasing market share compared to the more mature PbA storage, with the experts expecting that this trend will continue over the next ten years. Furthermore the high energy density of Li-ion batteries, exploited for the electric vehicle market that has been important in driving down the costs of the technology, provides a benefit over its heavier PbA counterparts when transporting equipment to remote or challenging locations [136].

Huld et al. [139] used energy systems modelling to compare the effects of using PbA and Li-ion storage in minigrids for rural electrification across a wide geographic area covering Africa and South Asia. The authors found that using the same effective storage capacity for each technology resulted in an increased reliability of service when using Li-ion batteries, owing to their superior technical performance, and a greater resilience to changes in demand profiles. Similar results were also found by Jaiswal [140], Ayeng'o et al. [141] when comparing the use of PbA and Li-ion batteries in solar home systems.

Table 3.3 The cost and embedded emissions of battery storage, grid extension and diesel generation. *: Per kWh of installed storage capacity. Adapted from Sandwell et al. [111].

Electricity source		Cost	Emissions
Li-ion battery*		\$350/kWh [137, 145]	527 $kgCO_{2eq}$/kWh [142, 143]
Grid electricity		\$0.05/kWh [146]	788 gCO_{2eq}/kWh [147]
Grid extension	Plains	\$2030/km [44]	15 tCO_{2eq}/km [148]
	Mountains	\$4600/km [44]	
Diesel	Fuel	\$0.67/litre [149]	1056 gCO_{2eq}/kWh [150]
	Generator	\$300/kW [151]	

The improved technical performance of Li-ion compared to PbA batteries, and its decreasing costs, suggest that more systems will be deployed using Li-ion batteries in the future. Furthermore, if the share of systems using Li-ion storage increases in the future as predicted [135, 136], then analysis considering the long-term impact of these systems may become increasingly relevant. For these reasons I consider the use of Li-ion batteries as the energy storage technology in the off-grid systems in this work.

As explained in section 2.4.2 I account for degradation of the batteries based on the number of expected cycles over its lifetime, depth of discharge, and the total energy throughput. In this chapter, as only one simulation period is considered, the battery storage is replaced when it reaches 60% of its original capacity whenever this occurs in the simulation period [142–144]. The costs and embedded emissions of the battery storage are shown in table 3.3.

Diesel generation and grid extension

Diesel generation has been, for many years, a common method of providing off-grid electricity to rural areas but can be expensive to operate and suffers from high emissions intensities [113, 114]. Grid electricity can provide power at a lower price but this cost is increased when investments in infrastructure are taken into account [44, 45]. I use these two options as counterfactual examples of alternative electrification strategies to put the results of the

off-grid PV systems in context. Details of their costs and environmental impacts shown in table 3.3.

3.2.3 Simulation and optimisation process

Model description and simulation parameters

In this analysis I simulate the energy systems over a 20-year time horizon. A range of combinations of PV and storage capacities are modelled individually over the system lifetime and, for each, the energy generated by the system, demanded by the community, stored or provided by the storage, and dumped as excess is recorded at an hourly resolution, as well as the state of charge of the battery to identify periods of energy shortfall. Inefficiencies in the energy conversion and transmission processes are accounted for, as well as the degradation of components. I take the lifetime of the inverters to be ten years and the lifetimes of OPV (Today) and (Future) modules to be five and ten years respectively. I assume that, as their expected lifetimes are longer than the simulation period [16], replacement of c-Si, CPV and CdTe modules is not required. Electricity generation from each PV technology is calculated using the methods describe in section 2.4.2 from data from the NREL SUNY dataset, which provides hourly irradiance and weather data at an hourly resolution [92]. The code used to generate the results in this chapter is available from appendix B.

Technological cost and performance data is shown in tables 3.2 and 3.3. The cost and emissions of grid electricity, and of extending the network, is taken from the literature [44, 152, 153] which distinguishes the cost difference between grid extension in flat and mountainous terrains. The emissions intensity of diesel generation is taken from the literature [150] and the cost of electricity is calculated from then-current (2015) diesel prices [149, 151]. These are used to assess the impact of the system, both in terms of effectively meeting demand and their financial and environmental costs.

Optimisation process and criteria

I assess each combination of PV and battery capacity in their ability to provide energy to the rural community. The energy generated, used, dumped and unmet is recorded for each system as well as the costs and environmental impact. I consider any system which provides an average blackout percentage of $\overline{B} \leq 0.05$ to be sufficiently reliable in meeting the needs of the community, whilst sacrificing the most extreme periods of high demand occurring at times of low generation and storage levels. I select as the optimum the system with the lowest LCUE $\mathscr{L}$.

An overview of the results of the simulation and optimisation process is shown in fig. 3.4. Each combination of PV array size and battery storage capacity is simulated and the LCUE is plotted as a colour plot, with the white lines superimposed upon the figure as contours of equal blackout percentage $\overline{B}$ and labeled accordingly. The black line traces the optimum combination of PV and storage such that LCUE is minimised over the system lifetime.

Poorly-designed systems, for example with large amounts of storage capacity but little PV capacity or vice versa, suffer high LCUEs shown in red, whilst well-designed systems with low LCUEs are shown in blue. The global minimum of LCUE occurs for a value of $\overline{B} = 0.25$: this is the point at which additional system investments yield a lower rate of return, but also at which a similarly well-designed but smaller system would not utilise their capacities as effectively. White contours of $\overline{B}$ which are almost vertical or horizontal illustrate the areas in which adding storage and PV capacities, respectively, would be futile in improving reliability, highlighting the need to design the system well.

For uniformity I consider a baseline scenario summarised in table 3.4 to assess the impact of the system in a given context. The baseline system is composed of c-Si PV and Li-ion battery storage deployed in Ladakh, with $B_{\text{thr}} = 0.05$ and optimised to minimise LCUE whilst meeting the domestic demand profile. Systems and analysis considered in this chapter

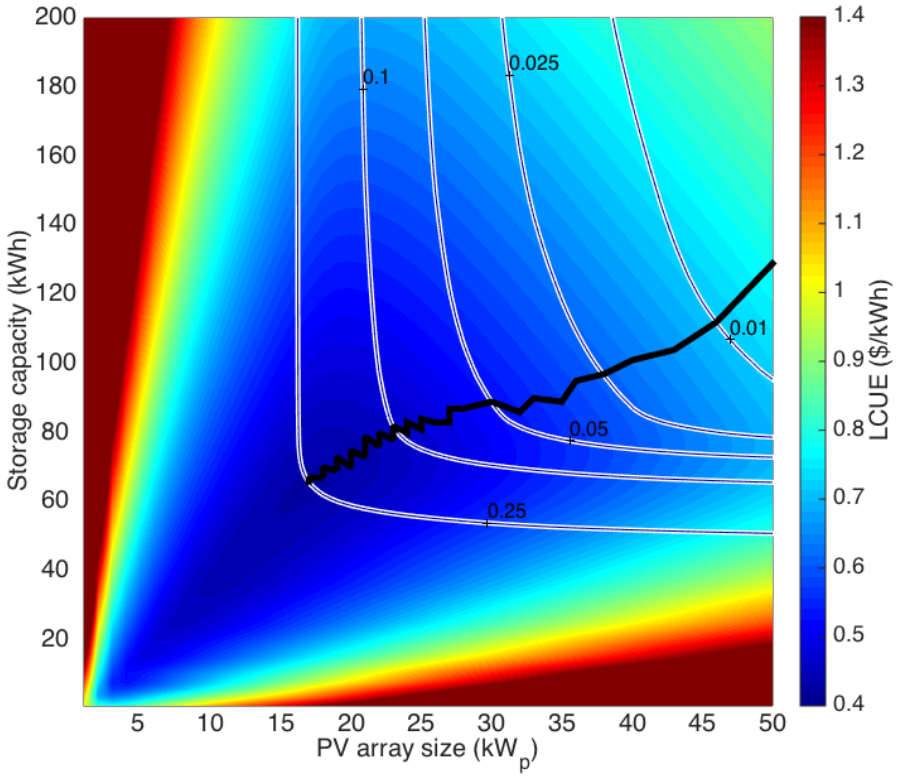


Fig. 3.4 The LCUE (colour bar) of various combinations of c-Si PV capacity and Li-ion battery storage capacity, with contours of equal blackout proportion (white lines) and optimum systems (black line). From Sandwell et al. [111].

Table 3.4 The parameters used in the baseline scenario.

Parameter	Value
Location	Ladakh
Community size	500 households
Demand type	Domestic
PV technology	c-Si
Battery technology	Li-ion
Blackout percentage	$\overline{B} \leq 0.05$
Optimisation criterion	Minimum LCUE

use these parameters unless stated otherwise, for example using different PV technologies or deploying in different locations to investigate the effects of changing these conditions.

3.3 Assessment of electrification options

3.3.1 Performance of PV technologies

Financial assessment

The LCUE and LCGE of the PV technologies are shown in fig. 3.5 a) and b) respectively. At the costs considered an LCUE of between \$0.46–1.20/kWh can be achieved. Significant cost contributions come from the PV module and its installation, and from the battery storage; the latter is caused by the relatively poor mismatch of the times of irradiance and demand. Battery storage is used to mitigate this but its high cost disincentivises excess capacity being installed and results in significant amounts of energy being dumped, ranging from 42–70% of the total generation.

CPV suffers a high LCUE in comparison to other technologies owing to its poor performance during overcast periods. As it utilises DNI only it can generate power only when the sky is clear, whereas the other technologies can operate under diffuse light conditions. This intermittency inflates the LCUE as the system must be oversized to compensate for the

reduced periods of accessible solar resource, in particular with regards to batteries, and the majority of generated energy is dumped. It may be the case that decreases in battery costs that occurred after this study, and further decreases in the future [138], will reduce this effect and make CPV systems more competitive in the future.

OPV also has a higher LCUE than established technologies, largely caused by the cost of replacing the modules because of their short lifetimes. The OPV (Future) case, however, suggests that the LCUE of OPV could be reduced to levels comparable to that of mature technologies even if the lifetime of the modules remains shorter than their established counterparts.

CdTe outperforms c-Si in terms of LCUE owing to its lower module costs. These two technologies provide far lower LCUEs than either of the emerging technologies at their present prices and performance.

Regardless of the technology chosen to supply the minigrid system, it is important that the electricity services that are provided are affordable to the community that receives them. An assessment of the affordability will depend on many factors such the typical household income of the community; data relating to the economic situation of communities in Uttar Pradesh are available in chapter 5. Further discussion of the relative affordability of systems such as the ones considered here can be found in chapter 7, where any configuration of PV minigrid provides a significant reduction in both cost and GHG emissions in comparison to kerosene lighting and incumbent diesel generation.

Environmental impact

The energy intensity of the module production is a major contributor to the total system specific emissions, as can be seen in fig. 3.5 c). It should be noted that the specific emissions for these systems are far higher than those that have been found in other studies [17, 18, 23, 24] for several reasons. Firstly, a significant proportion of the generated energy is not able to

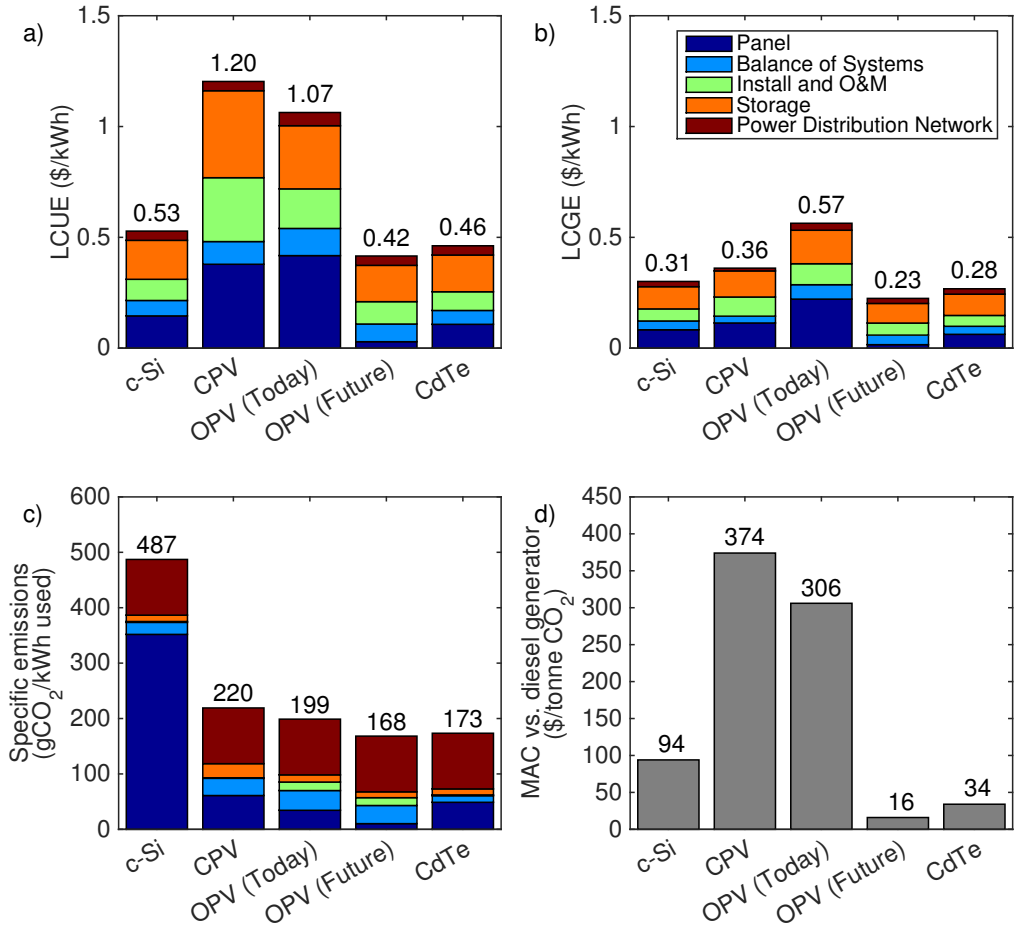


Fig. 3.5 The a) LCUE, b) LCGE, c) specific emissions and d) MAC of c-Si, CPV, OPV (at present and in the future) and CdTe technologies. From Sandwell et al. [111].

be used which attributes the same total system GHGs to a much lower electricity usage; this is not the case for other grid-connected case studies where it is assumed that all of the energy is either used or exported to the grid. The systems presented here also include considerations towards battery storage and the local power distribution network which are not, typically, included in PV LCAs [16] but are relevant to include here. Finally, for c-Si technology in particular, the embedded emissions of the panel are particularly high as I consider production in China where the GHG emissions from manufacturing are far higher than those in Europe, for example [17]. These considerations provide a more accurate reflection of the impact of a system in reality and so are more appropriate for my analysis.

CdTe offers the lowest emissions, at 173 gCO_{2eq}/kWh, whilst c-Si results in the highest, at 487 gCO_{2eq}/kWh. Despite the low environmental impact of a single OPV module its need to be replaced several times during the system lifetime inflates the overall emissions, as does the increased area-related BOS requirements from more framing being required by its low module efficiency. These could be reduced as the technology improves, shown in the OPV (Future) case. Despite having the highest LCUE, CPV has relatively low emissions as it uses only a small amount of photoactive material, but the steel used in its frame and tracking system increase the environmental impact. Again, as an emerging technology, both the cost and GHG emissions associated with CPV technology may yet decrease. A significant contribution to emissions of all of the off-grid systems considered here is the power distribution network, a result of the use of large amounts of copper which has a high environmental impact from its mining and extraction processes.

The high emissions associated with c-Si, a result of the energy-intensive silicon production process, may represent a concern to system designers who have been motivated to provide a low-carbon solution for rural electrification. The specific emissions are far lower than those from either grid or diesel electricity, and are negligible during the use of the system, but should not be ignored when the entire lifetime impact is considered. This could reduce the

mitigation potential of PV systems but is unlikely to negate it as the difference in emissions between systems supplied by PV and via fossil fuel generation is so large.

The LCUE and emissions vary considerably between the different PV technologies and the two are not correlated. As considered here, the LCUE is more likely to be used to select a system for deployment at present but by considering the MAC of each system against the cheaper, but more emissions-intensive, diesel generators we can consider the cost of choosing to provide a cleaner generation option. The lowest and most favourable MAC at present is achieved using CdTe, displacing GHGs at an equivalent cost of \$34/tCO_{2eq}, a result of both its low cost and low emissions. In contrast, CPV and OPV have far greater MACs and are not considered a cost-effective method of abating GHGs. The MAC of c-Si is comparably low at \$94/tCO_{2eq} owing to a combination of its low cost and that the emissions from diesel generation are more than double those of c-Si. If the performance improvements and module costs decreases materialise as modelled in the OPV (Future) case, the extremely low environmental impact of OPV could provide a significant opportunity for abating GHGs. Similar performance improvements and cost decreases may be possible for another novel PV technology, perovskite solar cells; owing to the emergent nature of this technology I have not assessed perovskite PV to the same degree as the other technologies but provide some details about its potential in the box below.

Perovskite photovoltaics for rural electrification

Perovskite solar cells have attracted a significant amount of interest and have experienced rapid increases in their performance but remain a pre-commercial technology. Using estimates of their potential performance once they reach a commercial scale [154, 155], costs comparable to those of OPV (Future) [8, 9] and LCA studies [82, 156, 157] I find that the LCUE at a lifetime of one year is prohibitively high at \$2.63/kWh but for lifetime of five years the LCUE is comparable to current technologies at \$0.74/kWh.

If perovskite solar cells experience a similar reduction in embedded energy to that of OPV [31, 81] then the emissions intensity of an off-grid system could fall to 270 gCO_{2eq}/kWh. This could be attractive to developers but, before this can become a realistic possibility, significant manufacturing upscaling needs to occur [155].

There is also a significant potential to mitigate GHGs from kerosene lamps which are used by rural communities in India to fulfil their lighting needs. This is not considered in this chapter however I establish the baseline for this in chapter 5, describe the way in which this can be modelled in chapter 6, and assess the impacts of kerosene mitigation in chapter 7.

Comparison of demand profiles

The timing and magnitude of demand can affect the performance of the system and for this reason I compare the domestic and additional income-generating load profiles, shown in fig. 3.2, in terms of their effect on LCUE and specific emissions, shown in fig. 3.6. The total demand considered in the latter case requires 71% more energy on average to satisfy demands for commerce and small industry, but can do so with an 11% reduction in both LCUE and specific emissions compared to domestic demand alone. One cause of this is the reduction in the influence of the distribution network which, for a similar investment in

equipment, satisfies far more energy demand and reduces its impact relatively to the rest of the system.

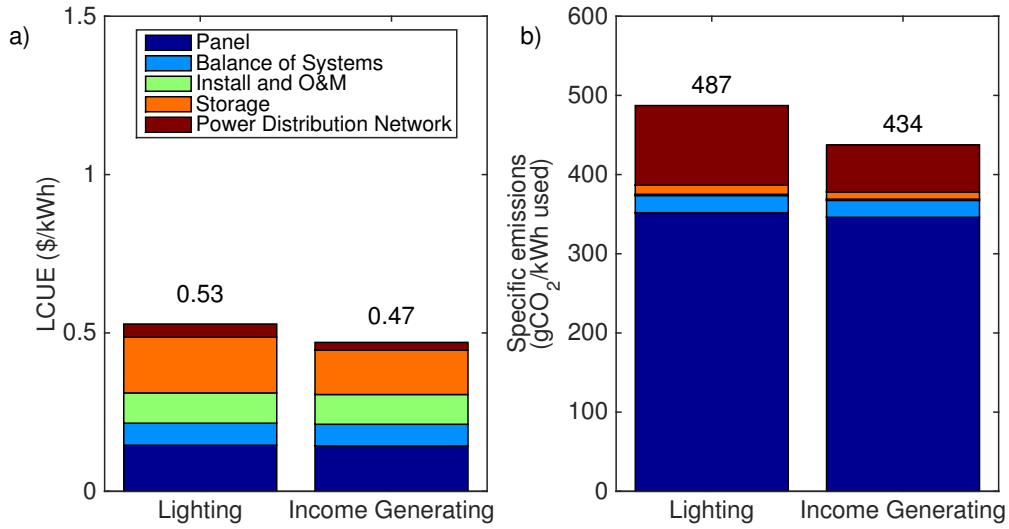


Fig. 3.6 The a) LCUE and b) specific emissions of the domestic and income generating load profiles. From Sandwell et al. [111].

Another reason is that the closer matching of energy demand to generation achieved by introducing the income-generating loads reduces the amount of dumped electricity and improves system performance. Successfully deploying a minigrid system for productive applications may come with additional challenges, however, such as matching the seasonality of demand, financing a significantly larger system, and ensuring the local business ecosystem is capable of using, and paying for, the amount expected.

3.3.2 Comparison to grid extension

Financial assessment

Here I consider the baseline system, deployed in each of the three locations, in comparison to the grid network and diesel generation. The LCUE of each configuration is shown in fig. 3.7 a), where distance has no impact on off-grid systems and the effect on grid-connected

systems depends on the local topology [44]. The data used for calculating the impact of diesel and grid-connected systems is shown in table 3.3 where I assume no loss of supply occurs. When no extension distance is required the cost of grid electricity is taken to be \$0.05/kWh [147] and the lifetime cost of diesel generation is calculated to be \$0.37/kWh.

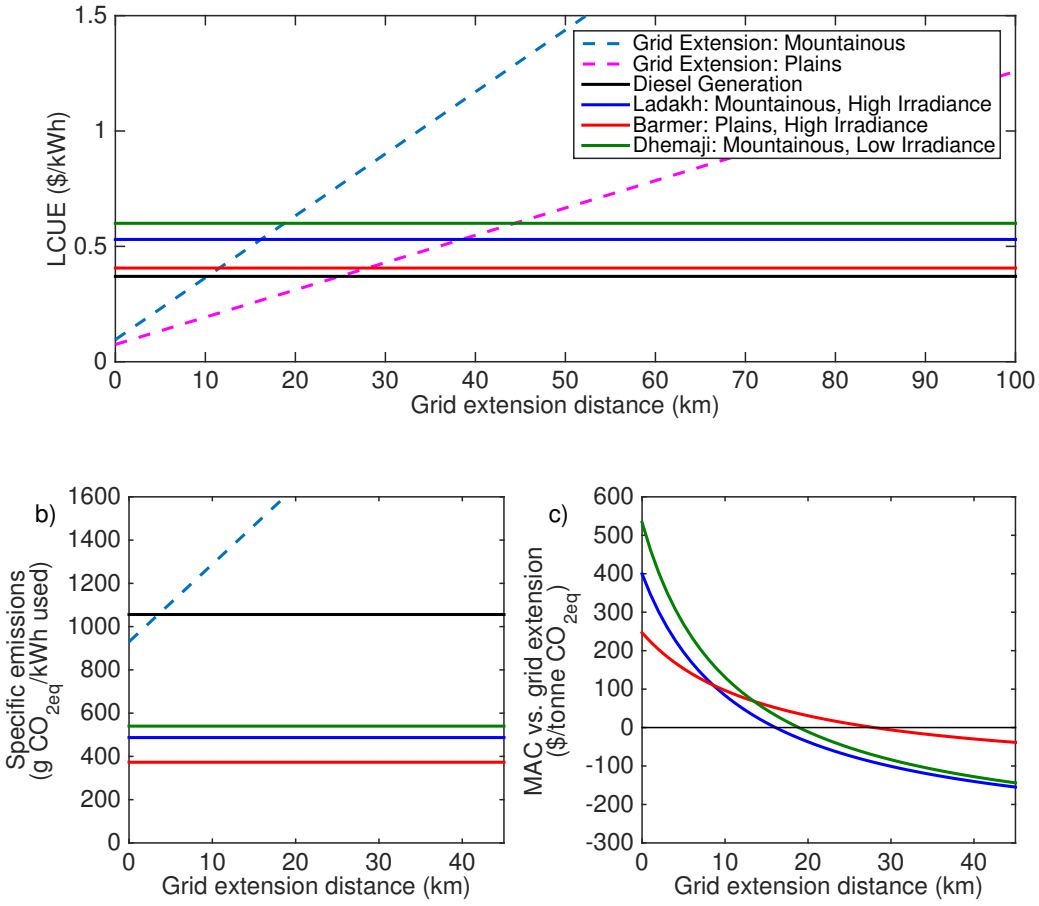


Fig. 3.7 The a) LCUE, b) specific emissions and c) MAC of c-Si compared to grid extension and diesel generation in Ladakh (blue), Barmer (red) and Dhemaji (green). From Sandwell et al. [111].

The dependence of both the local topology and the extension distance required on the cost of grid electricity is greater than that of the irradiance on the LCUE of PV systems. Both mountainous locations have similar breakeven distances despite different levels of irradiance;

at 16 km and 19 km for Ladakh and Dhemaji respectively; these values are similar to those found in previous studies [152, 153]. Barmer, located in terrain more kind to grid extension, has a greater breakeven distance of 28 km despite receiving the highest average irradiance.

The LCUE of systems in the two hilly locations, at $0.53/kWh and $0.60/kWh, are more similar to each other than to that of the plains location, $0.41/kWh. This could be caused by the greater seasonal variation found in Ladakh: despite a higher irradiance on average, the overall performance is limited by that during the winter months when the solar resource is lowest, resulting in the system being comparatively oversized.

In terms of the cost of electricity, this analysis shows that the distance to the existing grid network is the greatest factor in determining which areas should be considered for off-grid PV systems. The electricity needs of communities more than around 19 km away from the grid in mountainous regions, and 29 km in plains regions, would be met more economically via PV generation than grid extension. Diesel generation remains the cheaper option in the former case but PV systems can provide a comparable LCUE in the latter.

In the future it is likely that these grid extension distances will change. As well-established infrastructure, the national grid network and its extension is unlikely to experience major cost decreases, at least with regards to rural electrification. The reductions in PV module prices and battery storage, however, will reduce the total cost of PV minigrids and with it the cost of electricity and the breakeven extension distance. Furthermore, volatility in diesel prices may affect the LCUE of diesel-powered systems. I chose the financial parameters used in this work to be the best reflection of the situation at the time the research was undertaken but, as costs change rapidly, these may become unrepresentative over time.

Environmental impact

The emissions of grid electricity will be a function of grid extension as additional resources, in particular GHG-intensive copper and other metals, are required to build the distribution

network. This is shown in fig. 3.7 b) where the emissions from off-grid PV systems, between 373–540 gCO_{2eq}/kWh, are far lower than the grid for all extension distances, at 930 gCO_{2eq}/kWh and above. Diesel generation is also less carbon intensive than the grid when it must be extended by more than 4 km to reach the community.

Similarly to the LCUE, the grid extension distance has a greater impact on emissions than the local level of irradiance. PV systems offer a reduction in the GHG intensity of the electricity used by at least 516 gCO_{2eq}/kWh compared to diesel generation and 390 gCO_{2eq}/kWh compared to the grid, even before extension is taken into account, a saving of almost 50% for both.

The MAC of installing off-grid PV systems in place of the grid is shown in fig. 3.7 c); as before, local irradiance has a far smaller effect on the MAC than the grid extension distance. In locations close to existing grid infrastructure the MAC is as high as \$540/tCO_{2eq}, but for the most remote communities a MAC as low as –\$150/tCO_{2eq} could be achieved. The negative MAC is a result of the grid extension distance being greater than the breakeven distance and means that, at extension distances greater than 19 km in mountainous regions and 28 km in plains regions, deploying a PV minigrid is both cheaper and produces less GHG emissions.

3.3.3 Performance of hybrid systems

Financial assessment

Combining PV, storage and diesel generation in a single hybrid system would allow a greater matching of power supply to the demand of the community: renewables generation can be used as much as the local resource will allow and a diesel generator can be utilised to satisfy any remaining demand. The LCUE achieved by using using hybrid systems in meeting 100% of community energy demand is shown in fig. 3.8 a); analogously to fig. 3.4, the white lines indicate the blackout percentage of the PV and storage components, with the shortfall now

being met by diesel generation. Using the cost data given in tables 3.2 and 3.3 I find that the systems with the lowest LCUE feature the smallest investments in renewables. This result is unsurprising given the earlier analysis that found the LCUE of diesel generation to be lower than that of PV and storage systems.

Environmental impact

The specific emissions of hybrid systems is highly dependent on the generation capacities in the system, as shown in fig. 3.8 b), with systems with low PV and storage capacities and heavily reliant on diesel generation having correspondingly high emissions. In contrast the optimum system considered in the baseline scenario earlier, which met 95% of demand through PV and storage, a hybrid system of the same composition but now also meeting the remaining 5% via diesel generation has an emissions intensity of 539 gCO_{2eq}/kWh: this is 11% higher than the renewables-only system, but 49% lower than diesel alone.

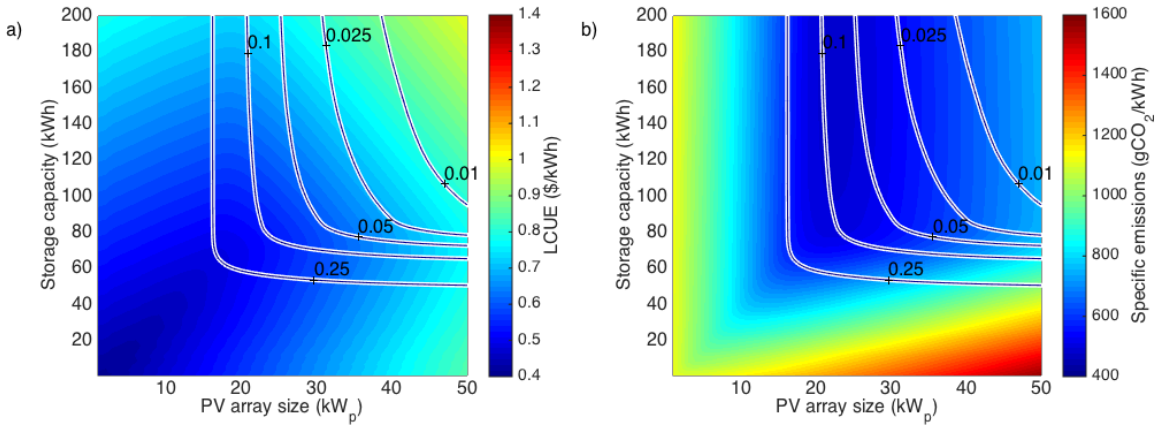


Fig. 3.8 The a) LCUE and b) specific emissions (colour bars) of PV-storage-diesel hybrid systems, with contours of equal blackout proportion (white lines) and optimum systems (black line). From Sandwell et al. [111].

The importance of optimising a hybrid system is also highlighted in fig. 3.8 b). Despite supplying less than 1% of the energy demand through diesel generation, systems with the highest capacities of PV and storage suffer greater emissions than those using diesel for only 5–10% of demand, which have the lowest emissions. This is a result of a mismatch of supply

and demand which causes the system to be oversized, embedding additional GHGs in PV and storage capacities that are used to meet a comparatively small proportion of demand.

Future hybrid systems

Diesel prices are subject to variation caused by, for example, changes in oil prices, subsidy reforms and local price fixing [158–161], and a price increase would have a significant effect on the optimum composition of a hybrid system. To investigate this effect, and that of the expected price decreases in battery technology as a result of performance improvements and manufacturing innovation [137, 145, 162], I consider a range of potential diesel and storage prices and identify the optimum system with the lowest LCUE for each combination. As in the simulations earlier I assume there are no fluctuations around the stated price, which is constant throughout the simulation period.

For each optimum system the fraction of the total energy demand met by diesel generation and the specific emissions of the system are shown in fig. 3.9 a) and b) respectively. Historic diesel and battery prices are marked '2015' and guideline projections for 2020 and 2025 are shown as an indication of potential future costs, based on a 10% per year decrease for Li-ion battery storage [142, 145, 162] and a 10% per year increase for diesel prices [158–161].

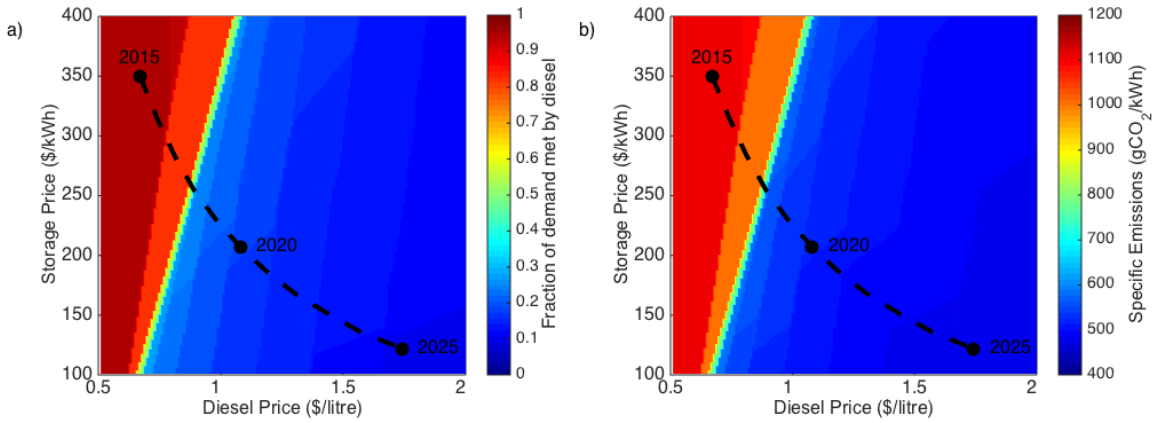


Fig. 3.9 The a) fraction of demand met by diesel generation and b) specific emissions of cost-optimised PV-storage-diesel hybrid systems at various storage and diesel prices, with indicative values for 2015, 2020 and 2025 shown. From Sandwell et al. [111].

I find a sharp transition from optimum hybrid systems which are powered almost entirely by diesel generation to those with 80% or more of the energy supplied by PV and storage, shown in fig. 3.9 a). An increase in diesel price has more of an effect on this transition than a decrease in storage price as the impact of the former on the LCUE of diesel generation is relatively larger than the contribution of storage price to renewables systems. As this transition occurs a corresponding decrease in the emissions of the hybrid system is observed in fig. 3.9 b), from more than 1000 gCO_{2eq}/kWh to less than 600 gCO_{2eq}/kWh.

This transition will have a significant impact on the design of hybrid systems: those designed under the assumption of low diesel costs and high storage costs will be more expensive to operate once prices change, not only locking the community into systems with high GHGs but also costing more in the long term. Furthermore, hybrid systems with lower fractions of demand met through diesel are more resilient to price fluctuations and can provide a more stable and predictable LCUE: this would provide a significant benefit to minigrid developers charging a fixed tariff or for investors using financial projections to assess the risk of the project.

Hybrid systems can provide better demand matching and lower LCUEs than those powered by PV and storage alone but must be designed and optimised with the entire system lifetime taken into account. The cost projections shown in fig. 3.9 suggest that the transition point for system design to shift from a majority of energy being generated by diesel to a majority supplied by renewable sources is either imminent or, potentially, could have already occurred. This represents a turning point for minigrid developers and could provide a significant benefit in reducing the emissions intensity of the electricity supplied to off-grid communities.

3.4 Conclusions

3.4.1 Summary of results

In this chapter I have assessed the performance and impact of PV technologies, diesel generation, grid extension and hybrid systems in meeting the electricity needs of a rural community. I found that mature technologies, c-Si and CdTe, can offer the lowest LCUEs at \$0.53/kWh and \$0.46/kWh respectively whilst OPV could become cost-competitive in the future if performance improves and costs decrease as expected. Systems powered by CPV were highly reliant on battery storage which inflated their LCUE and resulted in 70% of the electricity that was generated being dumped. The energy-intensive manufacturing process of c-Si modules results in a high specific emissions of 487 gCO_{2eq}/kWh whereas those for CdTe and OPV (Future) were far lower, at 173 gCO_{2eq}/kWh and 168 gCO_{2eq}/kWh respectively. Despite this the MAC in comparison to diesel generation for c-Si was relatively low, at \$94/tCO_{2eq}, although the lowest of current technologies was found to be \$34/tCO_{2eq} for CdTe. Introducing income generating demands was found to lower both the LCUE and specific emissions owing to superior demand matching.

Breakeven grid extension distances were calculated as 19 km and 28 km for hilly and plains regions respectively, whilst the emissions of off-grid PV systems in all locations was far lower than those of diesel generation and the grid. For communities in areas further from existing grid infrastructure than these breakeven distances, deploying PV minigrids would provide both cost savings and GHG reductions in comparison to grid network expansion.

I presented the impact of using hybrid systems to meet demand and found that, at the time of this research, the low cost of fuel and high cost of storage means that systems with the lowest LCUEs are dominated by diesel generation but they also suffer the highest emissions intensities. As these costs change in the future a transition will occur: the composition of future hybrid systems will be dominated instead by electricity from PV and storage

and will result in correspondingly lower emissions. Using projections to identify potential trends will be important in ensuring that future energy systems can continue to provide affordable electricity with low GHG emissions as technology improves and as the needs of the community change, as I will explore later.

3.4.2 Impact of PV technologies in off-grid systems

Off-grid PV systems can provide power to rural communities but the choice of PV technology has a noticeable effect on the cost and environmental impact of the electricity supplied. The two mature technologies, c-Si and CdTe, both provide electricity at an affordable rate and, despite the higher specific emissions of the former, using either for rural electrification would provide significant GHG savings relative to diesel generation or the national grid. For the emerging PV technologies, the reliance of CPV on battery storage makes it unviable for off-grid systems and would suit instead utility-scale deployment, where it could feed into the grid and where no electricity dumping would occur. OPV, meanwhile, has the potential to provide low-cost power with little environmental impact but this will depend on technological improvements and testing before it can be considered as a suitable technology option.

Ultimately the GHG mitigation potential of these PV technologies will come as a result of them displacing power supplied by diesel generators or the grid. We have seen that, at present, the environmental benefits of PV systems comes at a financial cost to minigrid operators that could use, or are using, diesel generators and communities must be sufficiently remote from existing grid infrastructure to be considered for electrification via PV systems. As minigrid operators are likely to consider costs as the most important performance indicator across the lifetime of the system, other electrification options may be chosen ahead of PV until the financial balance changes, either by reductions in component prices or through interventions such as subsidies. Furthermore, the political drive towards grid extension in even the most

remote regions and the incumbent dominance of diesel generation for off-grid systems could slow the deployment of PV systems in rural areas.

Nevertheless, as technological performance improves and greater weight is given to environmental benefits, PV systems will be deployed more widely. It is likely that mature PV technologies, and in particular c-Si, will be used PV minigrids owing to continuing cost reductions and presenting the lowest technological risk. My analysis of hybrid systems has shown that the expected future performance of PV generation and storage will incentivise renewables generation and switching to off-grid PV systems, either from existing diesel systems, as part of a hybrid system, or in areas currently without access to electricity, will facilitate the provision of affordable, sustainable and reliable power.

3.4.3 Impact on future work

The results presented in this chapter highlight some of the opportunities for PV technologies in off-grid systems but require further research to address additional questions. The electricity demand of the community is critically important in the optimisation of the systems however the load profiles used in this study, as in many others, feature no variation between days or throughout the year. Whilst this can serve as an approximation or an upper bound of total demand it does not capture the day-to-day variability which would be present in a real system. Furthermore, the demand profiles used here do not increase over time to reflect economic growth within the community and therefore do not capture a key development goal.

Furthermore I have assessed the benefits of PV systems in relation to other electrification technologies but not in their ability to mitigate the use of kerosene lamps. Communities without electricity are highly reliant on kerosene for lighting and any form of electric lighting would offset the usage of kerosene lamps and therefore their expense to the community and their GHG emissions. Accounting for the amount of kerosene offset by any system supplying electricity will add an important dimension to the analysis of electrification options.

I establish the baseline for this analysis in chapter 5 and explore the modelling and impact of kerosene mitigation in subsequent chapters.

This chapter considers the use of the grid, and its potential extension, to meet electricity demand but in reality the decision process can be more complex. Some villages have received grid infrastructure but no households have a connection, or those that do receive an unreliable service which does not meet their needs. In these communities it may be more suitable to investigate how an unreliable grid service can be combined with traditionally off-grid options, such as diesel and PV generation, to combine and supply a more reliable service.

We have seen that emerging PV technologies are currently outcompeted by their mature counterparts for rural electrification. In the case of OPV, further research and development will be necessary in order to achieve the performance improvements and cost reductions to be considered as a viable option for rural electrification. For CPV, however, the technology is ready for deployment but this should be in more favourable conditions such as those with more reliable DNI and with the opportunity to feed into the grid.

Finally, the simulation and optimisation process used in this chapter uses a 20-year time horizon which, although recommended for PV LCAs [16], does not include any improvements in the level of energy access of the community other than from the initial deployment of the system. It would be more realistic, therefore, to incorporate growing demand as mentioned previously and a shorter time horizon which better reflects the shorter-term goals of minigrid developers. By considering for a few years at a time a system can be designed to be adequate in the short term, then can be reoptimised and added to modularly in the future to expand in response to a growing electricity demand. This will allow the same lifetime period to be considered but in several shorter stages to ensure the system is not oversized whilst remaining suitably reliable.

In the following chapters I build on the analysis presented here to further establish the potential of PV technologies to mitigate GHGs. In chapter 4 I perform an LCA of a novel

design of CPV module and assess its impact in several locations around the world. In chapter 5 I present the results of a fieldwork survey whose results provide a baseline against which electrification options can be compared, and also device usage data which can be integrated into energy systems models. I describe an improved modelling framework in chapter 6, which includes the improvements outlined in this section, and in chapter 7 I present the results of using this framework in assessing the suitability and GHG mitigation potential of PV technologies for rural electrification.

Chapter 4

Life cycle analysis of the Fullsun HCPV module

Acknowledgement of contributions

Geoffrey Duggan provided the materials breakdown of the HCPV module, advised on the manufacturing processes, suggested potential deployment locations, and calculated the energy yields and LCOEs for each location. Geoffrey Duggan, Jenny Nelson and Ned Ekins-Daukes advised on the direction of research and supervised the work. All other work is that of the author.

Previous presentation of this work

This work has been published as an article in *Progress in Photovoltaics: Research and Applications* [163]:

Sandwell P, Duggan G, Nelson J and Ekins-Daukes, N. The environmental impact of lightweight HCPV modules: efficient design and effective deployment. *Prog. Photovolt: Res. Appl.* 2016; **24**:1458-1472. DOI:10.1002/pip.2802. Work from this article is reproduced with permission [164].

This work was presented as an oral presentation:

Sandwell P, Duggan G, Nelson J and Ekins-Daukes, N. Life cycle analysis of the Fullsun photovoltaic module. At *11^{th} International Conference on Concentrator Photovoltaic Systems (CPV-11)*, Aix-Les-Bains, France, 13–15 April 2015.

4.1 Introduction

4.1.1 Overview

As an emerging technology, high concentration photovoltaic (HCPV) systems aim to provide a viable alternative to traditional PV designs. Instead of using large photoactive areas like those of established PV technologies, HCPV instead utilises systems of lenses and mirrors to focus sunlight onto smaller, more efficient solar cells. The goal of this is to minimise the investment in expensive III-V multijunction cells in favour of optical systems which, it is hoped, will reduce the overall cost of the system. A result of using these optics is that only direct normal irradiance (DNI) can be collected, rather than all ambient light, and limits the viable deployment range of HCPV to arid regions where cloud cover is minimal and overcast conditions are rare.

Third generation III-V multijunction cells used in HCPV modules have consistently experienced both higher efficiencies and greater improvements in efficiencies over time than those of first and second generation PV [128, 165] but the cumulative installed capacities of systems using them lag behind those using conventional technologies. In 2015 the worldwide cumulative installation of HCPV systems stood at just 340 MW [12] compared to more than 100 GW for crystalline silicon [166] and, in order to increase its share of deployment, HCPV systems must provide a competitive advantage over the other technologies currently available.

One such advantage may be the reduced environmental impact of HCPV systems. The contribution of energy and GHG intensive processes for solar cell manufacture can be reduced if a smaller cell area is used for a given unit of capacity but this benefit must not be outweighed by the increased contribution of mounting and tracking structures necessary in HCPV systems. It may be that the environmental benefit can be increased if the HCPV system is designed to minimise the materials used in its construction, which is the case for a

module manufactured by Fullsun Photovoltaics Ltd. The company has designed a lightweight and low-profile HCPV module that represents a case study of an innovative module design and, working in collaboration with them, we performed an independent analysis to assess its potential to mitigate GHG emissions.

In this chapter I will use life cycle analysis (LCA) to assess the environmental impact of the Fullsun module and systems using them, as well as their potential to mitigate GHG emissions. As we have seen from chapter 3, off-grid electricity systems supplied by HCPV are limited in their ability to provide cost-effective power owing, in part, to their reliance on battery storage to supply reliable power in regions with sporadic DNI. Here, instead, I assess their opportunity to provide sustainable power in the context of utility-scale generation to understand their potential in mitigating GHGs from grid electricity in realistic and favourable deployment locations.

Few studies investigate the environmental impact of HCPV systems and, of those that do, none have analysed the potential of lightweight modules. Using well-established LCA methodologies from existing studies I undertake a novel analysis of the Fullsun module as a case study of an innovative HCPV module design. I provide for the first time a quantitative assessment and comparison of its environmental impact, both for the module manufacture and its deployment in HCPV systems, to assess its potential to mitigate GHG emissions.

A graphical overview of this chapter is given in fig. 4.1. In section 4.1 I will provide a summary of the literature of PV and HCPV LCAs to put the work of this chapter in context. In section 4.2 I use a breakdown of the module materials to assess the cumulative energy demand (CED) and total embedded GHGs of one Fullsun module until the end of the manufacturing process and, by normalising the result for performance, compare it to the impact of other HCPV modules. In section 4.3 I consider the additional impact of trackers, transportation, end-of-life management and other components to calculate the CED and GHGs of systems using Fullsun modules. By accounting for system performance I

calculate the energy payback time (EPBT) and carbon payback time (CPBT) in six potential deployment locations. I present the emissions intensities of these systems and compare them to other renewable technologies, as well as estimates of their lifetime LCOE. I consider the effect of policies that would introduce a cost on GHG emissions and the impact this would have on the viability of Fullsun HCPV systems. Finally, in section 4.4, I summarise the findings and establish the potential of Fullsun HCPV systems to mitigate GHG emissions.

4.1.2 Assessment criteria

In this chapter I will assess the environmental impact of the Fullsun modules and systems using several criteria. The focus, as with the rest of this work, is on the embedded energy and GHGs in relation to climate change mitigation and not, for example, on the ecological impact of manufacturing and deploying PV or their effects on human health [16]. The functional unit used in section 4.2 is one completed Fullsun module, and normalised for comparability to other studies in terms of its impact per W_p output. In section 4.3 the functional units are one installed and operational 6 kW_p Fullsun system and 1 kWh of electricity at the point of use.

I consider the CED, measured in megajoules of equivalent primary energy or MJ_{EPE}, as the primary metric of the total embedded energy. This allows us a uniform comparison between other studies and takes into account all of the materials and processes included in the creation of one functional unit. Similarly I account for the cumulative GHG emissions in terms of their total global warming potential over a 100-year time horizon in terms of the equivalent mass of CO_2 that would cause this [84]. I measure this in kilogrammes of CO_2 equivalent, or $kgCO_{2eq}$. More information about the processes of calculating these is given in section 2.6.2.

I use the EPBT and CPBT, both measured in years, to assess the efficacy of systems using Fullsun modules. These allow us to calculate the amount of time it will take for a system to

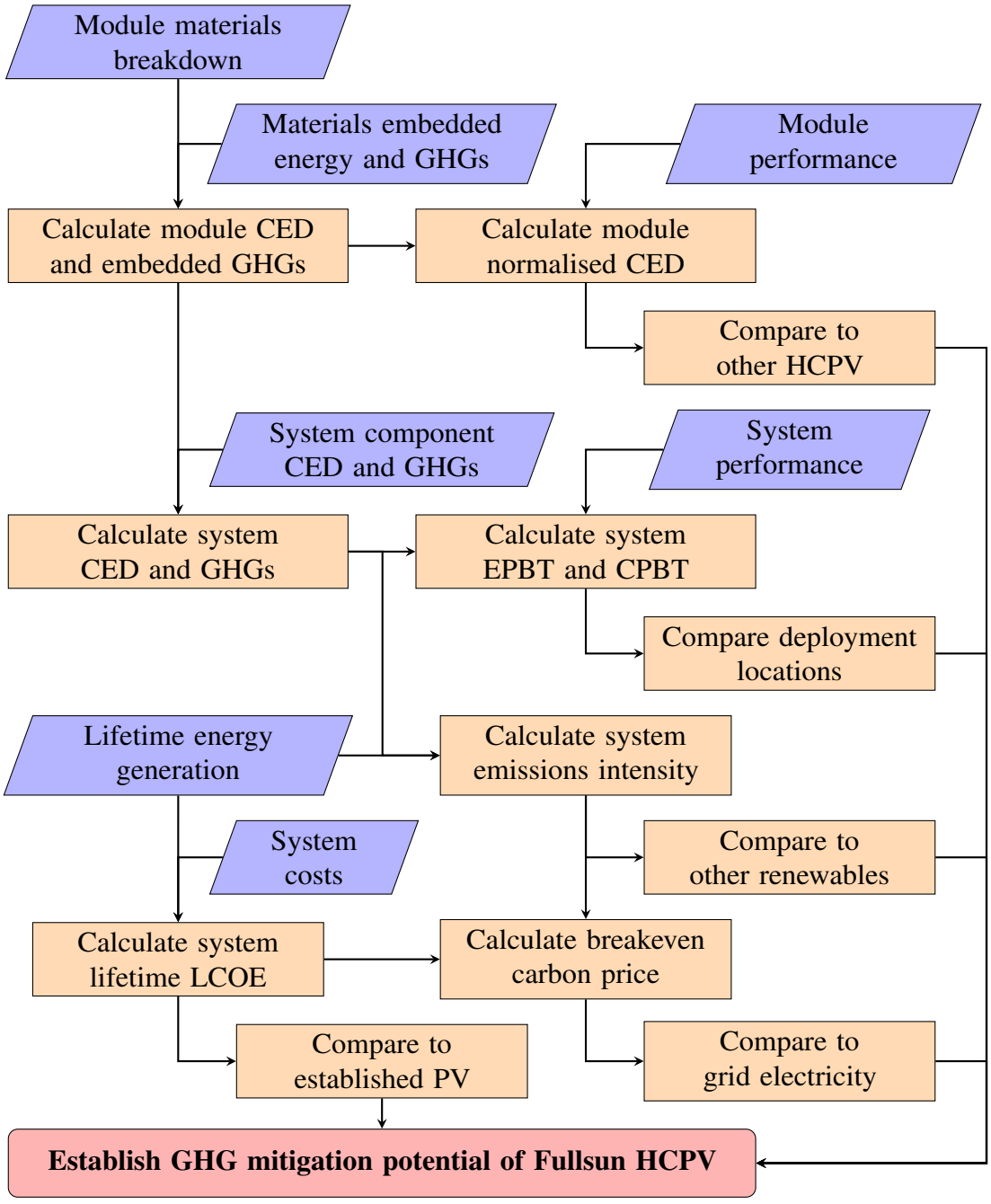


Fig. 4.1 Graphical overview of chapter 4.

produce more energy or offset more GHGs than were used in its construction. These can be taken to be the time it takes for the system to break even in terms of its environmental impact. The processes and equations used in calculating the EPBT and CPBT are given in section 2.6.3.

Two metrics are used to assess the electricity produced by Fullsun systems. For the environmental impact I consider the GHG emissions in grammes of CO_2 equivalent per kWh of power available at the point of use, or gCO_{2eq}/kWh. The second, to analyse the financial viability of the systems, is the levelised cost of electricity, LCOE, measured in US dollars per kWh. The methods of calculating these are given in section 2.6.4 and section 2.5.3 respectively. Finally, I consider the introduction of policies that would financially discourage the emission of GHGs and the impact this would have on deploying Fullsun systems; more information about this is outlined in section 2.6.6.

4.1.3 Literature summary

LCA of mature PV technologies

The most common form of LCA studies for established PV technologies aim to quantify the energy and GHGs embedded in the construction of a module or system [16]. The scope, assessment criteria and boundaries of these studies vary but are generally motivated by analysing the costs and benefits of PV technologies in the context of promoting their deployment ahead of other electricity sources. As the design and use of PV technologies changes, LCAs must be updated to ensure their relevance and accuracy: mature silicon and thin film PV technologies have received LCA studies focusing on a wide variety of applications, from domestic rooftops and utility-scale power plants to remote off-grid electricity systems and small solar-powered lamps [16, 17, 20, 21, 83, 119, 123, 167, 168].

Owing to the breadth and volume of available literature I focus on harmonised LCA studies which distill many studies into a meta-analysis and review. The harmonisation

process involves gathering LCA studies and discarding any which do not reach the required standard of detail or rigour necessary for further consideration. The remaining studies are then normalised by applying the same values for every performance parameter in each, for example using the same level for irradiance in each study where before several were used to represent different locations around the world. By reducing the effect of using different assumptions between studies the variations within a single type of technology, for example the type of PV used, can be isolated. This allows the authors of harmonisation studies to find the distributions of reported results and give, for example, the median as a representative value for the literature as a whole.

A harmonised study by Hsu et al. [23] investigated the GHG emissions of crystalline silicon (c-Si) in ground-mounted and roof-mounted installations, which was further segregated into multicrystalline silicon (multi-Si) and monocrystalline silicon (mono-Si) technologies. A summary of the median emissions calculated by their harmonisation study is shown in table 4.1, with systems of both technologies achieving a median emissions intensity of 32 gCO_{2eq}/kWh in regions with the highest irradiance. The factory location was not harmonised and is reflected in the range of data they present: the authors identified that the manufacturing location has a significant impact on the embedded GHGs of the module owing to the effect of the high emissions intensity of the local grid electricity, in particular for China. As the study was undertaken in 2012, however, manufacturing innovations may have reduced these values since publication. The authors concluded that the efficiency advantages attained by mono-Si are approximately offset by its more energy intensive manufacturing process, and another study by the same authors suggested that reducing materials requirements could lower the emissions intensity of both mono-Si and multi-Si [169].

A comparable harmonised LCA study was presented by Kim et al. [24] for thin film PV technologies: amorphous silicon (a-Si), cadmium telluride (CdTe) and copper indium gallium diselenide (CIGS). In high-irradiance areas, receiving 2400 kWh/m^2/year, ground-mounted

Table 4.1 The median emissions intensities of harmonised LCA studies of mature PV technologies. Adapted from Sandwell et al. [163].

Study	Technology	Installation	Irradiance ($kWh/m^2/year$)	Median emissions (gCO_{2eq}/kWh)
Hsu et al. [23]	c-Si	Ground	1700	48
		Roof	1700	44
		Both	2400	32
	Multi-Si	Both	1700	40
	Mono-Si	Both	1700	47
Kim et al. [24]	a-Si	Ground	2400	20
		Roof	2400	21
	CdTe	Ground	2400	14
		Roof	2400	26
	CIGS	Ground	2400	20
		Roof	2400	27

utility-scale systems using these technologies achieve median emissions intensities of 14–20 gCO_{2eq}/kWh. These lower values are indicative of the lower embedded energies and GHGs of thin film technologies in comparison to their crystalline silicon counterparts [17]. As before in Hsu et al. [23] the study was undertaken in 2012 and as such manufacturing innovations may have reduced the environmental impact of modules being produced at present, but this may be offset by the increasing proportion of modules being manufactured in China.

These harmonised studies of mature PV technologies provide a benchmark against which the performance of the Fullsun systems can be measured. HCPV systems will need to be able to compete with mature PV technologies to secure deployment in the most attractive high-irradiance locations and, if the emissions intensity of Fullsun systems is to be their unique selling point, their emissions intensities must be lower than the median values reported in these studies. If this is achieved, Fullsun systems may be a viable option for mitigation GHG emissions by providing low-carbon electricity to the national grid network.

LCA of HCPV technologies

HCPV technologies have attracted less attention than their mature counterparts but nonetheless several designs have received LCAs; this has been to assess both their environmental impact and their performance relative to established PV technologies. One of the earliest studies was undertaken by Peharz and Dimroth [25] in 2005 and analysed the impact of the FLATCON® system designed by the Fraunhofer Institute for Solar Energy Systems. The system, which uses a 500× concentration to achieve a module efficiency of 26%, was found to have the greatest contributions to the embedded energy and GHGs coming from components made of zinced steel and float glass, such as the tracking system and the module body respectively. The authors calculated an EPBT of 8–10 months for deployment in Spain and 12–16 months for deployment in Germany and, in a followup study by de Wild-Scholten et al. [26], the system was found to have an emissions intensity of 18 gCO_{2eq}/kWh. This value is within the range of median emissions intensities reported by Kim et al. [24] for thin-film PV technologies.

A study in 2006 by Der Minassians et al. [27] analysed the SolFocus Gen1 HCPV system. Significant contributions to the CED came from the large quantities of galvanised steel of the tracking system, as in Peharz and Dimroth [25], but there was also a large impact from the concentrator system. The optics provided 500× concentration via a concave primary mirror, convex secondary mirror and tertiary prism and, despite these components having a relatively small materials impact, the transportation from the supplier to the manufacturing plant alone accounted for 25% of the total CED. The authors highlight this as an area for improvement which, if reduced, could lower the EPBTs they calculate as 1.5 years for California and 1.3 years for Arizona.

Amonix, now Arzon Solar, was the leading developer in the HCPV industry with megawatt-scale installations in the USA and Europe [12]. As a result Amonix systems have been the subject of many LCAs [18, 28, 29] with the most recent being undertaken in

2013 by Fthenakis and Kim [170]. The authors analysed the Amonix 7700 system which is comprised of several large "MegaModules", again providing 500× concentration, mounted on a pedestal tracking system. The study accounts for the embedded energies and GHGs of all components and lifetime stages and calculates the impact of deployment in Las Vegas, Nevada and two sites in Arizona, Phoenix and Glendale. The authors find each location has an EPBT of 0.9 years and emissions intensities of 26, 27 and 27 gCO_{2eq}/kWh respectively. This is higher than the median values for established PV technologies and is a result, in part, of the significant impacts from the tracking system and heat sink required to cool the MegaModules during operation. The methodology used by Fthenakis and Kim [170] is the most thorough in the HCPV literature I consider and is used as a framework for this study.

From 2008–2013 the pan-European APOLLON project supported HCPV research and development [17] and, as part of this, an LCA was conducted by Timò [171] on systems provided by SolTec International. The modules, which operated at 30% efficiency, used mirrors and optics made from aluminium foil to focus light onto cells; aluminium was found to be the greatest component by weight, being the main material for the frame, base, receiver support and heat sink, and contributed 63% of the CED and 64% of the embedded GHGs. The author found that deployment in Sicily, Italy could yield an EPBT of 1.0 years and an emissions intensity of 20 gCO_{2eq}/kWh; given that the DNI value used in the calculations was 1794 kWh/m^2/year, these could be reduced by deploying in an area with higher DNI. The author compares these results favourably with other PV and HCPV technologies and argues for its competitiveness on grounds of sustainability.

A summary of HCPV LCAs from the literature, and including those already mentioned here, was compiled by Kammen et al. [30]. Using a harmonisation method similar to that used by Hsu et al. [23] and Kim et al. [24] for established PV technologies, the authors calculated EPBTs of between 0.5–1.2 years for HCPV systems and emissions intensities in the range 15–55 gCO_{2eq}/kWh. The authors used a DNI value of 2537 kWh/m^2/year for

their harmonised values, typical of the regions in which HCPV systems would be deployed, but used a relatively low performance ratio of 0.75. Whilst this is recommended for non-tracking PV LCAs [16] it is lower than that used by other HCPV reviews [170] and those found by experimental field studies [172, 173]. This may result in an overestimation of the environmental impact of HCPV systems and an unfair comparison to the LCAs of other PV technologies.

The HCPV system designs considered in the literature present similar EPBTs, all of which are far lower than the expected system lifetime, and values of emissions intensity which are close to or competitive with those reported for mature PV technologies. These are summarised in table 4.2. Their designs are broadly the same and significant contributions come from the necessity of heat sinks and heavy tracking pedestals to ensure efficient operation. In the following sections I will analyse the Fullsun module which eschews these features in favour of a lightweight and low-profile design which aims to minimise the environmental impact. By comparing the Fullsun module to those of other HCPV and PV technologies I will assess its potential to mitigate GHG emissions by providing sustainable power.

4.2 LCA of the Fullsun HCPV module

4.2.1 Materials and manufacturing process

Material breakdown

The Fullsun HCPV module shown in fig. 4.2 features 391 III-V multijunction PV cells each under a silicone secondary optical element (SOE) and mounted upon a printed circuit board (PCB). The module backplane, to which the PCB is attached, is composed of aluminium and copper and both encloses the module and acts as a heat sink, meaning that no additional components are required to cool the cells to ensure efficient operation. These are encased in

Table 4.2 Comparison of reported results of HCPV LCAs. NC: Not considered in the study. *: Results are for then-current (2009) values with then-future (2011) estimates in brackets. Adapted from Sandwell et al. [163].

System	DNI ($kWh/m^2/yr$)	EPBT (years)	Emissions intensity (gCO_{2eq})/kWh	Module CED (MJ_{EPE}/W_p)	Study
FLATCON®	1900	0.7-0.8	NC	5.8	[25]
	1000	1.0-1.3			
	1794	0.8	18		[174]
SolFocus	1825	1.5	NC	12.9	[27]
	2520	1.3			
Amonix 7700	1974	1.5	32	11.8	[174]
	2600	0.9 (0.8)*	26 (22)		[170]
	2480	0.9 (0.8)*	27 (23)		
	2570	0.9 (0.8)*	27 (23)		
APOLLON	1794	1.0	20	8.3	[171]

a housing made from aluminium walls and underneath a Fresnel lens matrix made of silicone and low-iron float glass, which acts as the primary optics of the module. The modules are produced in a pilot-scale manufacturing facility in Yorkshire, United Kingdom.

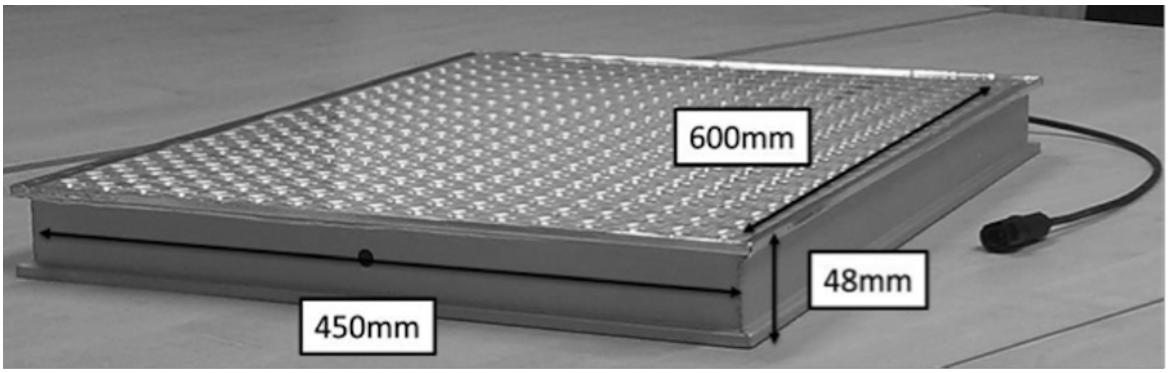


Fig. 4.2 Photograph of the Fullsun HCPV module and its dimensions. Photograph courtesy of Fullsun Photovoltaics Ltd. From Sandwell et al. [163].

The technical details and performance of the module were provided by Fullsun Photovoltatics Limited [175]. The module measures 600 mm by 450 mm in area (0.27 m^2) and is 48 mm thick, making it both thinner and more lightweight than those used in other HCPV systems. The optics of the module provide a 625× magnification factor and have an

acceptance angle of $\pm 0.8°$. We take the DC output of the module to be 34% under standard test conditions, an extrapolation from the currently-recorded performance of 30% when using 37% efficient cells, under the assumption that the same optical and electrical losses remain when upgrading to 42% efficient cells which had already been demonstrated at the time this analysis was undertaken [128]. Using this, we calculate the rated capacity of one Fullsun HCPV module to be 83 W_p. Since the time of this analysis, several manufacturers of multi-junction solar cells similar to those we consider have recorded cell efficiencies of greater than 44%, and commercial module efficiencies of up to 39% under similar magnification factors have been reported [4]. These results suggest that our extrapolation to a module efficiency of 34%, by replacing the current cells with more efficient counterparts, is reasonable but for greater certainty this would need to be experimentally confirmed under standard test conditions. If it were not possible to replace the current cells then the energy generation of the modules would decrease by 12% and would have a proportional effect on the results of my analysis, for example the EPBT and CPBT, as discussed later. Using technical drawings and measurements taken from the manufacturing processes supplied by Fullsun Photovoltaics Ltd. I calculated a breakdown of the module components and the materials used. These are shown in terms of their contributions to the total module mass in tables 4.3 and 4.4 and graphically in fig. 4.3.

The greatest contributions to the mass of the Fullsun module, similarly to other studies, are the structural components. The backplane, walls and lens are the most massive with the major component of the latter, low-iron float glass, representing the greatest single material by mass, followed by aluminium from the frame. Despite being numerous, the PV cells and bypass diodes contribute very little to the overall mass. With a cumulative mass of just 4.2 kg and a mounting capacity of 50.6 kg/kW_p the module is able to be mounted on lightweight trackers which do not require heavy foundations, unlike other HCPV modules.

Table 4.4 The materials breakdown of the Fullsun HCPV module by mass and fractional contribution to the total. From Sandwell et al. [163].

Material	Mass (kg)	Mass Fraction (%)
Glass	1.986	47.3
Aluminium	1.525	36.3
Silicone	0.341	8.1
Copper	0.214	5.1
Cables	0.088	2.1
Semiconductor	0.046	1.1
Total	4.200	100.0

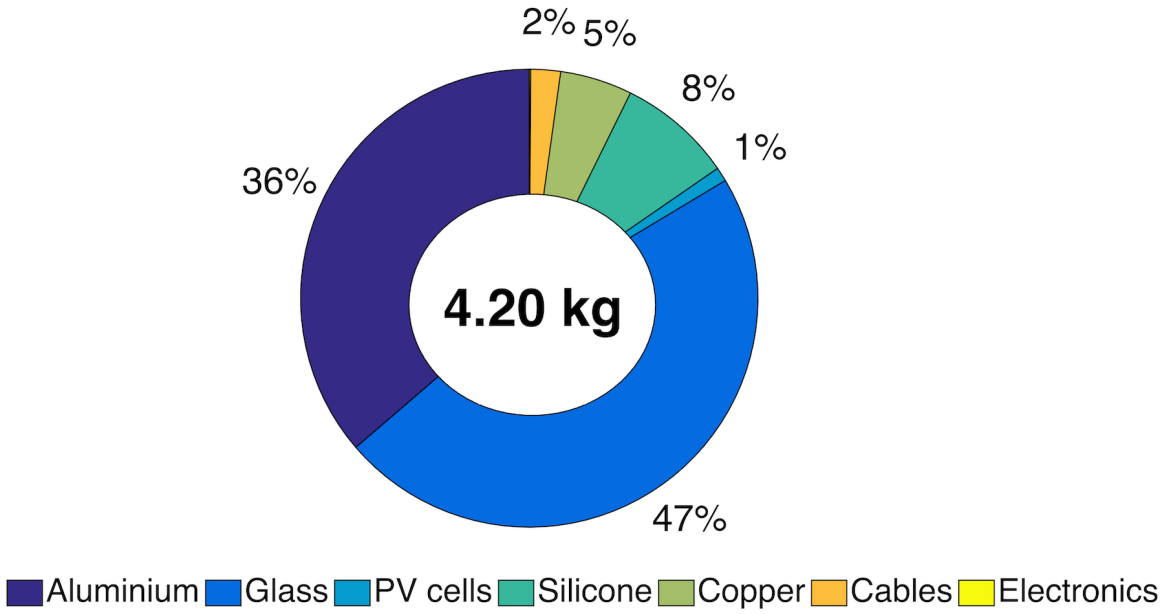


Fig. 4.3 Materials breakdown as a fraction of the total mass of the Fullsun HCPV module. From Sandwell et al. [163].

Table 4.3 Breakdown of the components of the Fullsun HCPV module in terms of mass and fractional contribution to the total. From Sandwell et al. [163].

Component	Material	Mass (kg)	Mass Fraction (%)
Lens	Glass	1.986	47.3
	Silicone	0.300	7.1
PCB backplane	Aluminium	1.072	25.5
	Copper	0.159	3.8
Walls	Aluminium	0.452	10.8
Sealant	Silicone	0.041	1.0
PV cells	Semiconductor	0.042	1.0
Bypass diodes	Semiconductor	0.004	0.1
SOEs	Silicone	0.000	0.0
Power connectors	Cable	0.088	2.1
Total		4.200	100.0

Cell manufacturing

The manufacture of III-V multijunction solar cells such as those used in the Fullsun module are not the subject of many LCAs, however those considered by Kim et al. [29], GaInP/GaInAs/Ge cells manufactured by Spectrolab using a metal-organic vapour-phase epitaxy process, provide an accurate comparison. The impact of these cells was used by Fthenakis and Kim [170] who assumed 10% of the inputs fall to wastage, also assumed here, and that the cells were 37% efficient. We have assumed that the cells used in the Fullsun module are 42% efficient at standard test conditions to reflect improvements in cell efficiencies [116, 176] that have been made since 2013 when the study by Fthenakis and Kim [170] was published.

Module manufacturing

The manufacturing processes used in the pilot-scale plant currently used to produce the modules are using a pick-and-place machine to put singulated die onto a lead frame, wire bonding of PV cells to the lead frame, moulding and curing silicone SOEs to make receiver packages, screen printing solder onto the PCB, placing the receiver packages onto the PCB,

curing the solder, and assembling the module. Owing to the modest capacity of the plant some of these processes, for example joining the walls of the module, are undertaken by hand and therefore not considered. If the manufacturing process were to be scaled-up in the future it is likely that these processes would be automated and their contributions to the total embedded energy and environmental impact would need to be reviewed.

4.2.2 Environmental impact of the module

CED and embedded GHGs

The majority of the CED and embedded GHGs originate from the materials used in the production of the module, where each contribution is found by taking the product of the mass of the material used and its energy or GHG intensity. Where possible I took values for energy and GHG intensity from *The Inventory of Carbon and Energy* by Hammond et al. [177] as this most accurately represents the location of manufacture, and otherwise I take values from comparable previous HCPV LCAs [25, 170]. Contributions from the sealants and power connectors were taken from academic [178] and industrial [179] literature respectively. I have assumed that the embedded energy and GHGs of the bypass diodes to be the same as for the PV cells; owing to their simpler manufacturing process this is likely to be an upper estimate.

I calculated the energy and GHGs from the manufacturing processes from the power requirements of the machines used, gathered from industrial datasheets [180–184] and which are assumed to be using grid electricity with the emissions intensity and primary energy conversion rate of the United Kingdom [108]. I account for the transport of components from the suppliers to the Fullsun factory [185–188] and include materials losses during the manufacturing process at 10% for PV cells [170], silicone sealant and glass and 5% for metal components. The breakdown of CED and embedded GHGs are given in fig. 4.4 and table 4.5.

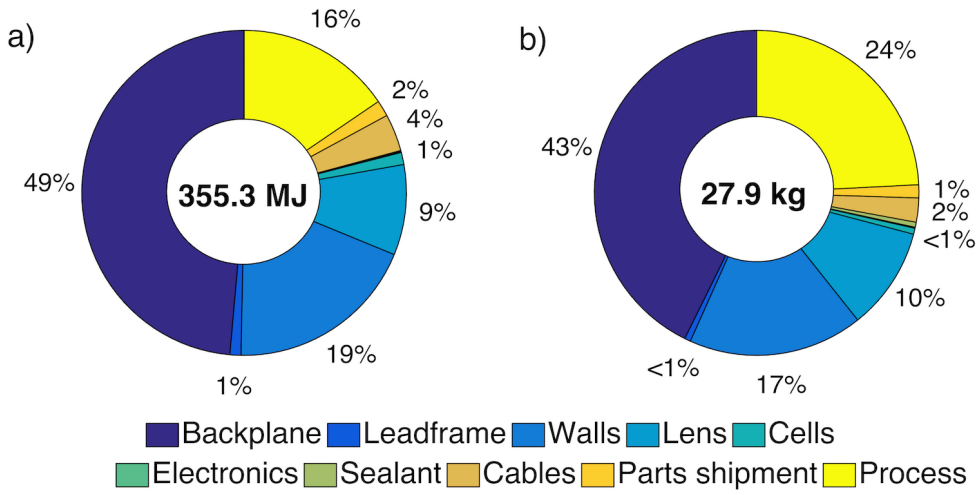


Fig. 4.4 a) Cumulative energy demand in MJ_{EPE} and b) embedded GHGs in $kgCO_{2eq}$ of the Fullsun HCPV module. From Sandwell et al. [163].

Table 4.5 Breakdown of the embedded energy and GHGs of the Fullsun HCPV module. The contributions from aluminium (Al) and copper (Cu) for the backplane are calculated separately and then combined to give a cumulative value. From Sandwell et al. [163].

Component		Energy intensity energy (MJ_{EPE}/kg)	Embedded energy (MJ_{EPE})	Energy fraction (%)	GHG intensity ($kgCO_{2eq}$/kg)	Embedded GHG ($kgCO_{2eq}$)	GHG fraction (%)
Lens		13.2 [25]	31.9	9.0	0.9 [177]	2.8	10.2
Backplane	Al Cu	143.0 [170] 69.0 [177]	172.9	48.6	10.2 [170] 2.7 [177]	11.9	42.7
Lead frame		69.2 [177]	4.0	1.1	2.7 [177]	0.2	0.6
Walls		143.0 [170]	67.9	19.1	10.2 [170]	4.8	17.4
Sealant		10.0 [178]	0.5	0.1	2.9 [177]	0.1	0.5
PV cells		-	4.2 [29]	1.2	-	0.2 [29]	0.6
Bypass diodes		-	0.4 [29]	0.1	-	0.02 [29]	0.1
Power connectors		150.0 [170, 179]	13.2	3.7	7.6 [170, 179]	0.7	2.4
Shipment		-	5.6	1.6	-	0.4	1.3
Process		-	55.1	15.5	-	6.8	24.2
Total			355.3	100.0		27.9	100.0

My assessment found that the cradle-to-gate module CED is 355.3 MJ_{EPE} and 27.9 $kgCO_{2eq}$ of embedded GHGs are emitted before the module leaves the factory. The energy-intensive processes used in mining and smelting aluminium contribute significantly to the environmental impact, however the glass of the lens contributes relatively little despite it being the most massive component. This demonstrates an advantage of the low-profile and lightweight module.

Whilst it is unlikely that the module frame would be made from any material other than aluminium, the float-glass lens could be replaced with a plastic substitute. The modules presented by Fthenakis and Kim [170] are made of acrylic glass, a transparent thermoplastic; using this material as a direct replacement of float glass in the Fullsun module would result in the lens reporting a contribution of 141.0 MJ_{EPE} and 0.4 $kgCO_{2eq}$, a significant increase for the CED and decrease for the embedded GHGs. This is caused as a result of the differences in manufacturing processes of the two materials: although a higher temperature is needed to produce float glass which is more emissions intensive, the scale of production is far greater than for acrylic glass which reduces the relative energy intensity. The use of acrylic glass for the lens would increase the total module CED to 467.4 MJ_{EPE}, an increase of 32%, and highlights the sensitivity of the environmental impact of the module to the choice of components.

The PV cells and bypass diodes contribute very little to the environmental impact, as does the shipment of the components to the Fullsun factory. This suggests that the manufacturing location is not a significant factor for this module as materials are sourced mainly from the UK and mainland Europe. In contrast, the SolFocus supply chain relied on shipping heavy concentrating optics from New York to California for assembly, increasing the contribution from transportation [27]. If all of the components were required to be shipped long distances before the module is constructed in the Fullsun factory then the CED and cumulative GHGs of the module would increase. Shipping all of the components from China, for example,

would increase the module CED by 75.4 MJ_{EPE} and embedded GHGs by 5.1 $kgCO_{2eq}$, an increase of 21% and 18% respectively. This is a significant increase but relatively lower than for the SolFocus system owing to the lower total materials burden.

The PV cells and bypass diodes contribute very little to the environmental impact, as does the shipment of the components to the Fullsun factory. This suggests that the manufacturing location is not a significant factor for this module as materials are sourced mainly from the UK and mainland Europe. In contrast, the SolFocus supply chain relied on shipping heavy concentrating optics from New York to California for assembly, increasing the contribution from transportation [27].

The module manufacturing processes contribute 15.5% of the CED and 24.2% of the embedded GHGs. The latter could be reduced by moving the factory to a location with a less carbon-intensive grid: Spain, for example, has a grid emissions intensity of 291 gCO_{2eq}/kWh owing to its high penetration of wind and hydroelectric power compared to 441 gCO_{2eq}/kWh in the UK [108]. Furthermore, Spain could provide a suitable local market for the technology.

Comparison to other HCPV modules

Normalising the CED and embedded GHGs by the output of the module allows us to compare the relative performance of the Fullsun module in the context of similar technologies. The module has a normalised CED of 4.3 MJ/W_p; this is shown in fig. 4.5 and is the lowest of the modules in the literature, the values of which were shown in table 4.2. All of the HCPV studies from the literature report use the same system boundaries when considering the production of the modules, including for example processing energies, parts shipments, and contributions from raw materials. Some studies, for example Fthenakis and Kim [170], provide significantly more detail in the contributions of each component compared to others, for example Timò [171], which aggregate components into categories without further detail. Using the data provided in these studies I have categorised the contributions as shown in

fig. 4.5; any miscellaneous components, for example silicone sealant, is included as "Misc." and any remaining contribution to the CED after named components were accounted for is included as "undefined", a result of the lack of explicit detail in those studies.

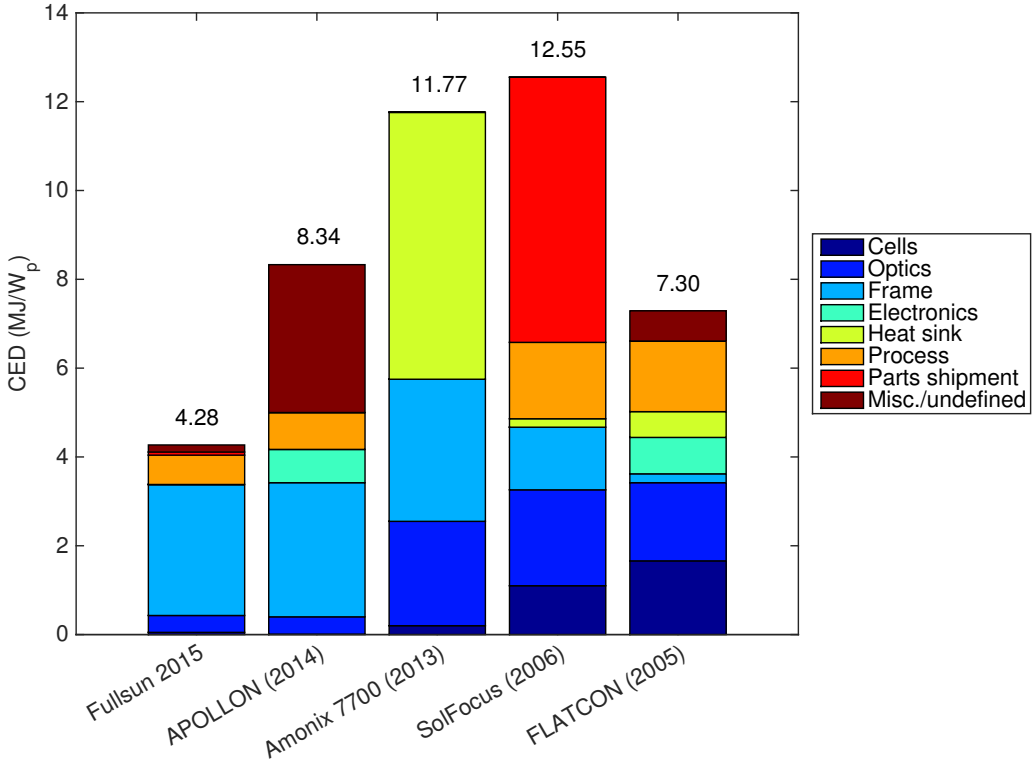


Fig. 4.5 Comparison of CED values per W_p for HCPV modules. From Sandwell et al. [163].

The Fullsun module has a greatly reduced impact compared to the Amonix 7700 [170] and SolFocus modules [27]. In comparison to the former it does not require a heat sink as this function is performed by the backplane, and compared to the latter the contribution of component transportation is far smaller. As mentioned previously, the shipment of parts from New York to California significantly contributes to the overall CED of the SolFocus system; if this contribution were decreased to levels comparable to the other HCPV modules then the normalised CED would be reduced to 6.58 MJ/W_p, the lowest of the previously-reported studies.

The contribution of the PV cells varies between the studies as a result of two estimates of their environmental impact: Der Minassians et al. [27] use data from the FLATCON study [25] whereas later analyses, including this work, use data from Kim et al. [29]. The contribution of PV cells decreasing over time can be attributed to improving cell efficiencies and manufacturing processes. In comparison, if the Fullsun module were to use the data from the FLATCON study for the impact of the PV cells, their contribution to the normalised CED would be 1.66 MJ/W_p and the total would remain the lowest of all of the considered studies at 5.89 MJ/W_p.

As considered earlier, if the Fullsun modules were to use acrylic glass, as in the Amonix 7700 system, in lieu of float glass then the CED of the module would increase. When normalised this would increase the impact of the module by 1.35 MJ/W_p to 5.63 MJ/W_p, still lower than the other studies. Additionally, if the Fullsun factory were to source all of its components from China, representing a large contribution to parts shipments similar to the SolFocus modules, then this would add a further 0.91 MJ/W_p to the normalised CED. I find that the cumulative effect of including the counterfactual cases of older data for the PV cells, the use of acrylic glass, and parts shipment from China to be that the normalised module CED increases to 8.15 MJ/W_p. This is a significant increase above the normalised CED I found for the current module manufacturing process and would mean that the environmental impact of the Fullsun module would be greater than the FLATCON study and the SolFocus study, if the supply chain of the latter is neglected. It is unlikely, however, that these theoretical increases in normalised CED would occur: increasing efficiencies of PV cells reduces their relative contribution, the glass used in the Fullsun modules has been tested and is also used by the APOLLON system, and if a scale-up in manufacturing required the import of materials from China then it would likely be more cost-effective to also manufacture the modules in that country also. Any of these contributions would increase the CED of the Fullsun module but,

as I have discussed, it will likely result in a normalised CED similar to the other modules in the literature rather than a significant deviation from them.

I have found that lightweight and low-profile Fullsun design presents a clear benefit in terms of reducing the materials usage and, in doing so, the embedded energy and GHG emissions. The normalised CED is lower than comparable HCPV modules which suggests that the environmental impact of deploying systems using these modules will also be lower, and their potential to mitigate GHGs to be higher, which I explore in section 4.3.

4.3 LCA of a Fullsun system

4.3.1 System description and deployment location

The efficacy of the Fullsun module should be judged in the context of an electricity-generating system, rather than as a module alone. In this section I consider the additional environmental impacts of the deployment of the entire HCPV system, including that of the tracker, shipment to deployment locations, assembly, balance of systems operation and maintenance and end-of-life management. This extends the earlier cradle-to-gate assessment to a cradle-to-grave analysis from the production of the module to the decommissioning of the system.

The system I consider is comprised of 72 Fullsun modules mounted upon a lightweight, commercially-available tracker [189]. The system is assumed to operate at a performance ratio of 0.93, comparable to previous studies [25, 170, 190] and operational data from existing systems [30, 173]. The performance of the modules is modelled to degrade linearly at a rate of 0.7% relative to their initial performance per year, corresponding to a 30-year system lifetime [16].

The lightweight tracker design used in this analysis has not yet been the subject of a dedicated LCA and as such I estimate its environmental impact by extrapolating from the work of Fthenakis and Kim [170]. Whilst the comparatively light modules I consider do

not require heavy tracking systems to hold their weight, it may be that the system must be made suitable massive using concrete foundations in order to stabilise the modules against the effects of motion caused by wind. To assess the potential impact of the need for concrete foundations I consider the large-area systems described by Fthenakis and Kim [170], which would be most susceptible to the effects of the wind. The mass of the modules, tracker and foundations per square metre of module area is reported to be 104.5 kg/m^2 [170]; the system I consider has a module area of 19.44 m^2 and would therefore require a total system mass of 2031.7 kg to achieve the same ratio as Fthenakis and Kim [170]. As the total mass of the modules and trackers is just 1388.4 kg, this would require an additional 643.3 kg of concrete to stabilise the system.

Using the same embedded energy and GHGs for concrete as in Fthenakis and Kim [170], I find that the additional impact of foundations per system to be 481.8 MJ_{EPE} and 88.5 $kgCO_{2eq}$, equivalent to 0.9–1.1% of the CED and 2.6–3.0% of the GHGs of the total depending on deployment location. This is relatively higher than the contribution found by Fthenakis and Kim [170], at 0.1% of the system CED and 0.6% of the GHGs, a result of the fact that the low masses of the modules I consider being compensated by heavier foundations. The use of concrete foundations is not recommended for the trackers I consider and so I do not include these contributions to the total system impact, although I discuss the potential impact of this assumption later in this chapter.

Estimates of the impact of the balance of systems, assembly, operations and maintenance were taken from Fthenakis and Kim [170] based on data recorded from active systems.

The performance of HCPV systems is highly sensitive to DNI and as such choosing an installation location is critically important. Furthermore the emissions intensity and power losses of the local grid network will influence the GHG mitigation potential of the system, and so the country of deployment will also contribute to the total environmental impact. We have selected six suitable high-DNI locations [191] to investigate the potential impact of

deploying Fullsun HCPV systems around the world: Phoenix, USA; Seville, Spain; Tabuk, Saudi Arabia; Haixi, China; Alice Springs, Australia; and Calama, Chile.

I calculated impact of shipping the modules and trackers from their respective factories to the deployment locations by finding the necessary transportation distances, via container ship and trucks, using a shipping company web application [185] and applying the energy and GHG emissions per tonne-km of goods of local transport [186–188]. I treat the end-of-life management in the same way as Fthenakis and Kim (2013) [170]: after the system has expired it is transported to a facility 100 km from the deployment site for recycling. Module components are separated at an energetic cost of 0.24 MJ/kg [192] but tracker materials are assumed to be homogenous enough not to require this step [170]. The materials are then shredded, requiring 0.1 MJ/kg [192], using machinery powered by local grid electricity. I assume that there is no energy or GHG benefit reclaimed by recycling the components or as part of the end-of-life management of the system.

4.3.2 Environmental impact

Energy payback time

I calculated the EPBTs and CPBTs for the six considered locations which are shown in table 4.6 and fig. 4.6. The EPBT of each system is strongly dependent on the local DNI and, as the deployment locations were selected based on this criterion, the values are relatively similar and most are in the range 0.29–0.33 years. Deployment in Calama, Chile, however, would result in an outlier EPBT of 0.22 years or just 80 days: this is because the Atacama Desert in which this system is considered to be deployed in is one of the highest-DNI areas in the world. Seville, despite having the lowest annual DNI, does not have the highest EPBT as the contributions from transportation increase the energy input for systems in Haixi. In all of the considered locations the EPBT is far lower than the expected system lifetime of thirty years, in some cases by two orders of magnitude.

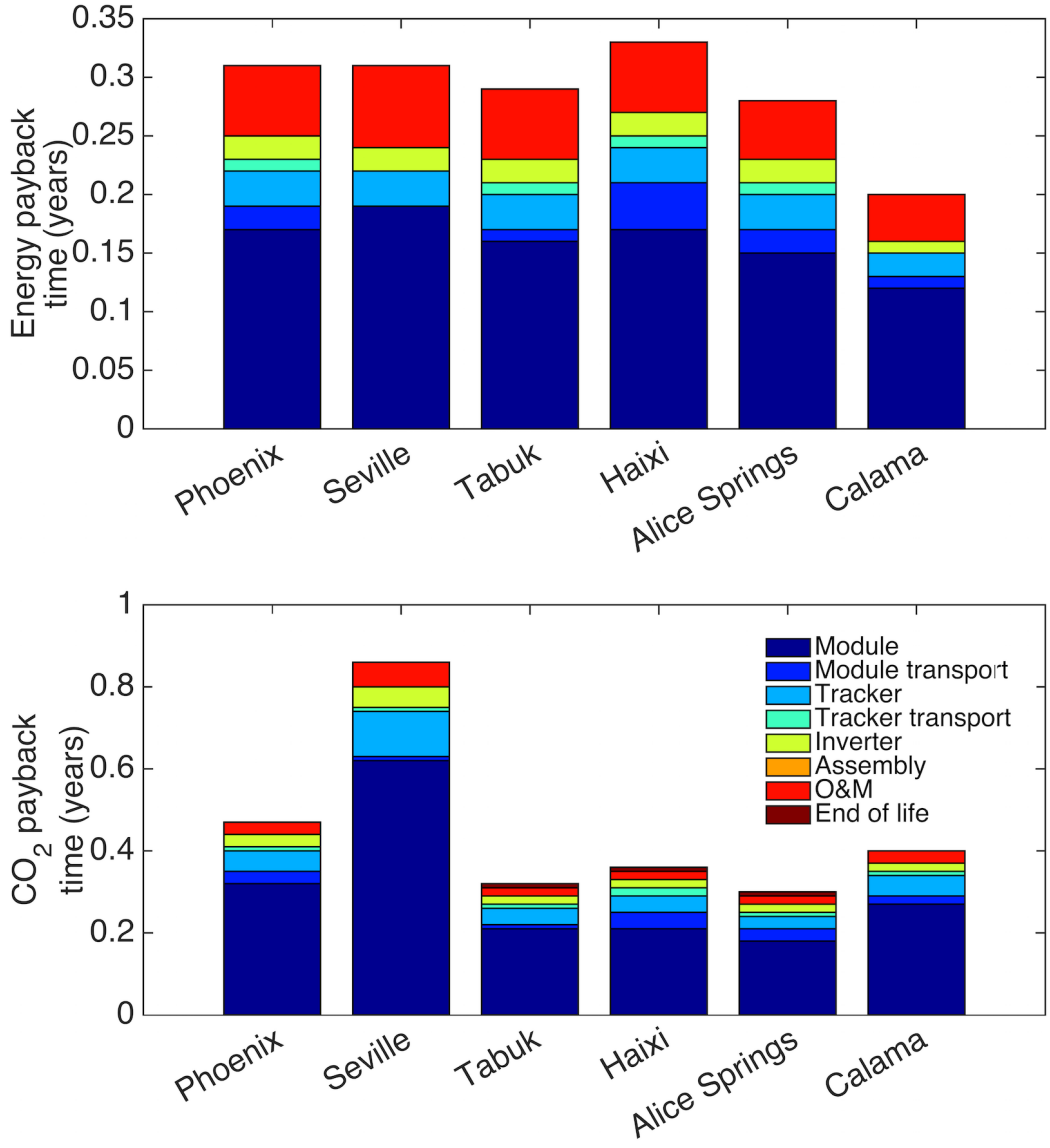


Fig. 4.6 EPBT (top) and CPBT (bottom) of systems using Fullsun HCPV modules in selected deployment locations. Note the difference in the scales of the vertical axes. From Sandwell et al. [163].

Table 4.6 Information about the six deployment locations considered and the emissions intensities, energy payback times and carbon payback times of Fullsun HCPV systems. Adapted from Sandwell et al. [163].

Location	Annual DNI (kWh/m^2) [191]	Grid losses (%) [46]	Emission intensity Grid [108] (gCO_{2eq}/kWh)	Emission intensity Fullsun (gCO_{2eq}/kWh)	EPBT (years)	CPBT (years)
Phoenix, USA	2482	6	503	9.0	0.30	0.48
Seville, ESP	2278	9	291	9.4	0.32	0.88
Tabuk, SAU	2668	9	754	8.3	0.28	0.30
Haixi, CHN	2409	6	764	9.8	0.33	0.35
Alice Springs, AUS	2668	5	823	8.8	0.29	0.29
Calama, CHL	3322	7	441	6.5	0.22	0.40

Carbon payback time

The CPBT is a function of both local DNI and the emissions intensity of the local grid. In the areas I consider the CPBT varies far more than the EPBT, from 0.29 years (106 days) to 0.88 years (321 days). Fullsun systems can have a greater impact in countries which have a higher emissions intensity, such as China and Australia, in comparison to those with more renewables generation, such as Spain and Chile [186]. As with the EPBT, the CPBT of each location is far less than the expected lifetime of the system; even for Seville, which has both the lowest DNI and lowest grid emissions intensity, the system takes less than one year to provide a net positive environmental impact.

Impact of uncertainties in the EPBT and CPBT

The lack of data for the impact of the lightweight tracker could result in the EPBT or CPBT being under- or overestimated, and similarly the exact location of deployment within the given regions considered here may add to the environmental impact by increasing the transportation contributions. The tracker and shipping combined contribute between 12–14% to the CED and 13–15% to the embedded GHGs. In addition, if concrete foundations were necessary to stabilise the tracking system then the CED would increase by around 1% and

the embedded GHGs would increase by up to 3%. If the contributions from the tracker and deployment were doubled, for example, concrete foundations were included, and the current 37% efficient PV cells were used rather than being replaced by higher-performance cells as I assume, the payback times would increase by only around six weeks and the total EPBTs and CPBTs would remain far below the expected system lifetime.

Furthermore the end-of-life process taken from Fthenakis and Kim [170], which assumes a disposal facility 100 km from the installation site, may have a greater impact than expected. Transportation from the deployment location to the facility accounts for 25–30% of the CED and 25–48% of the GHGs associated with the disposal process but the entire end-of-life management contribution is just 1–2% of the overall lifetime impact. Even if the facility were far further from the deployment location the additional impact would add just days to the payback times.

Emissions intensity of electricity generation

Whereas the EPBT and CPBT consider mainly the initial impact of a system with a view to finding the time taken to break even, the emissions intensity of an installed system provides a lifetime-averaged assessment of its total environmental impact and can be readily compared to other sources of power. Once again the high DNI of Calama provides the lowest impact, at just 6.5 gCO_{2eq}/kWh, whereas Haixi offers the highest emissions intensity of 9.8 gCO_{2eq}/kWh. I find that each of the considered deployment locations would yield an emissions intensity of less than 10 gCO_{2eq}/kWh, shown in table 4.6, and far less than those of the various local grids [108].

Comparison of emissions intensity to other renewable technologies

I have shown that Fullsun HCPV systems can provide low-carbon power with EPBTs and CPBTs far lower than their expected lifetimes, but in order to be viable for GHG mitigation

its environmental should also compare favourably with other renewable technologies. Here I consider the emissions intensities of established PV technologies, taken from Hsu et al. [23] and Kim et al. [24], and other renewables taken from harmonised studies analysed by Moomaw et al. [85] as part of a study for the Intergovernmental Panel on Climate Change (IPCC) in 2011. As highlighted before for the harmonised PV LCAs it may be the case that technological improvements may have affected these emissions intensities but, as the lifetimes of these technologies are far greater than the time since the study was published, we may assume that the reported values are representative of the generation capacity currently deployed and operational.

As an emerging technology the IPCC did not include HCPV in their report. I have therefore harmonised the previous HCPV LCA studies to the same performance ratio, 0.93, used for the Fullsun systems and irradiance levels typical of the southwest United States, which is the chosen location for the LCAs of established PV technologies [23, 24], to allow a fair and direct comparison.

The upper and lower bounds of emissions intensities plotted in fig. 4.7 represent the values of the 25^{th} and 75^{th} percentiles for each technology shown. Moomaw et al. [85] provides these data however this is unviable for the Fullsun and other HCPV systems owing to the small number of locations considered and limited number of studies undertaken. To overcome this, I take the reported values of emissions intensities from HCPV studies and the calculated values for Fullsun deployment locations and model them as two independent normal distributions, from which the values equivalent to the 25^{th} and 75^{th} percentiles are calculated and used in fig. 4.7. This process results in a small range of values, owing to the fact that the data has been drawn from several cases from the same study rather than cases from several different studies, but provides an adequate first-order estimation of how Fullsun systems could compare to other technologies.

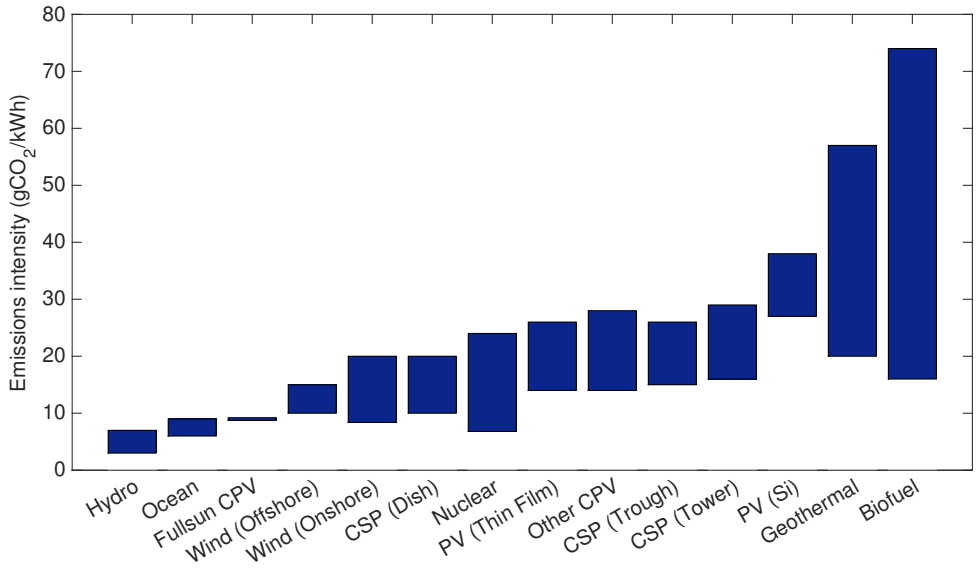


Fig. 4.7 The emissions intensities of Fullsun HCPV in comparison to other low carbon technologies. From Sandwell et al. [163].

The lower materials usage of the lightweight Fullsun systems leads to emissions intensities of around half those of their traditional HCPV counterparts. Furthermore the Fullsun systems report lower emissions intensities than thin-film and silicon PV technologies as well as dish- and tower-based CSP, all of which may compete against one another for favourable high-irradiance deployment locations. I calculate that Fullsun systems would be likely to have lower emissions intensity than other, established, low-carbon energy sources such as wind, nuclear and geothermal power. Fullsun systems are expected to be outperformed by hydropower, which is both well-established and can be deployed at far greater capacities than HCPV systems, and ocean power, which is still in the early stages of technological readiness. Nonetheless these two energy sources would likely be installed in very different locations to HCPV and so are unlikely to be direct competitors to Fullsun systems; they could instead be deployed complementarily as part of a wider low-carbon generation strategy.

Fullsun HCPV systems can supply power at emissions intensities lower than many established and widely-deployed technologies. The locations considered in this analysis were chosen specifically for their suitability for HCPV, potentially inflating their performance

relative to other renewable sources, but as an emerging technology these are the areas that are most likely to see commercial deployment and where the greatest benefits can be obtained. Fullsun systems are able to provide electricity with a low environmental impact but, before they can be deployed, they must be able to yield a competitive financial return to system operators.

4.3.3 Financial viability

Levelised cost of electricity

In order to be regarded as a viable energy source, Fullsun systems must be able to compete financially with other technologies. Estimates of the LCOE of other HCPV systems range from \$0.09–0.16/kWh, compared to \$0.07–0.11/kWh for other PV technologies, depending on the considered location [12]. When considering current costs and the potential savings that would be possible from scaling-up production, Fullsun Ltd. has calculated that an installed cost of \$1.10/W_p would be attainable, a value also estimated by Haysom et al. [11] for other HCPV systems. This cost has not yet been achieved by Fullsun Ltd., nor has it been reported by other HCPV manufacturers, and so serves as an estimate of what may be possible if manufacturing innovations are realised. This financial analysis is included as an indication of the potential long-term viability of the technology in favourable locations, rather than a statement of the current economic status, and as stated in this chapter and chapter 8 I consider this in the context of continually decreasing costs reported by mature PV technologies.

The LCOEs for Fullsun systems using the cost estimate of \$1.10/W_p, and that of traditional optimally-orientated flat-plate silicon PV systems, are shown in fig. 4.8. The installed cost of the traditional PV systems is assumed to be \$1.00/W_p in line with the 2020 goal of the SunShot Initiative from US Department of Energy [193] but, as discussed later, this is likely a conservative estimate as costs for mature PV technologies have decreased faster than expected by this programme. The same programme aims to reduce the LCOE of PV systems

to $0.06/kWh, a benchmark which is also shown. The LCOE calculations for Fullsun HCPV and flat-plate PV for all locations were performed by Geoffrey Duggan.

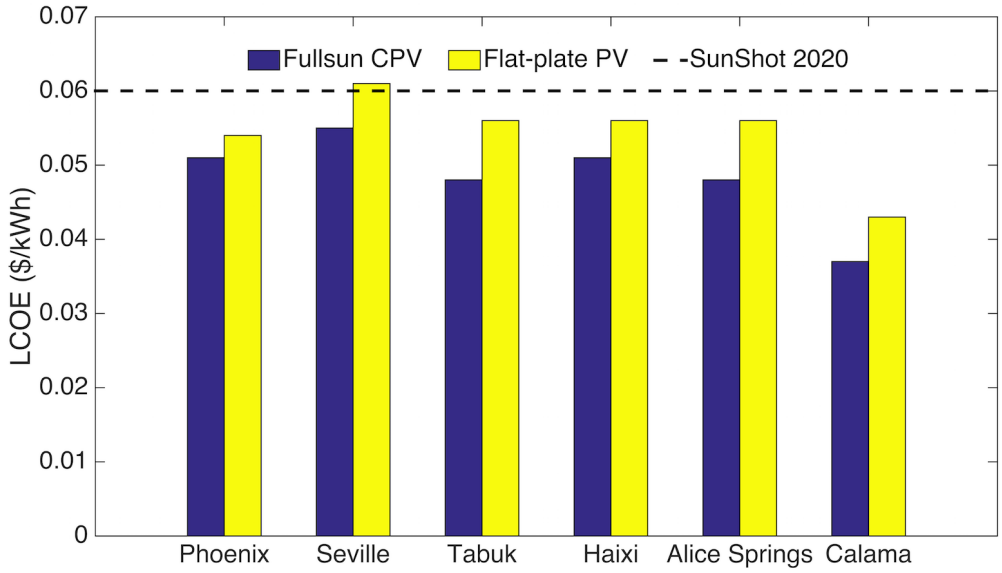


Fig. 4.8 The LCOE of a Fullsun HCPV system and a c-Si system at projected 2020 prices, in comparison to the SunShot 2020 target. From Sandwell et al. [163].

As LCOE is strongly dependent on the energy generated, and hence DNI, Calama experiences the lowest LCOE and Seville the highest, at $0.037/kWh and $0.055/kWh respectively. We calculate the LCOEs of Fullsun systems to be between 5–15% lower than those of flat-plate PV in each deployment location, however as the cost of traditional PV technologies continues to fall this difference may not materialise by the time Fullsun systems reach their projected cost. In 2017 the US Department of Energy announced that the 2020 SunShot Initiative target had been achieved, averaging $0.06/kWh across utility-scale installations [194], which may limit the appeal of HCPV in the USA in favour of traditional PV technologies. Furthermore, these locations were selected for their suitability for HCPV systems in providing high levels of DNI: in places where DNI is lower but GHI is comparatively higher, for example in regions with more cloudy days, optimally-inclined flat-plate systems may well outperform any HCPV system in terms of cost.

Nevertheless, in the locations considered here it is likely that Fullsun HCPV systems can achieve the target LCOE originally aspired to by the SunShot Initiative and should be considered economically viable if the cost reductions expected by Fullsun Ltd and Haysom et al. [11] can be attained. Their competitiveness with established PV technologies and other sources of generation, however, will depend on their the difference in their LCOEs and, potentially, on their emissions intensities.

Competitiveness with grid electricity

As well as being cost-competitive with other energy sources individually, a new technology must also be competitive with the cost of the local grid network in order to be seen as a realistic prospect. One method of making a low-carbon technology such as Fullsun HCPV more competitive would be to introduce a form of carbon price, either directly by placing a cost on the emission of GHGs or indirectly via subsidies for low-carbon generation, or their removal for high-carbon generation.

I investigate this by considering two factors, the difference in emissions intensity and LCOE between a renewable technology (low emissions, high LCOE) and the grid network (high emissions, low LCOE), and by calculating the effective cost of carbon that would negate the difference and mean the renewable technology now is cost-competitive. As the cost and emissions intensity of grid power will vary significantly around the world, and will change over time, I plot the difference between these two values on the axes of fig. 4.9 and the colour plot shows the carbon price required to break even. Solid white lines are plotted at proposed carbon prices for 2020, 2025 and 2030 at \$60, \$106 and \$180/tCO_{2eq} respectively [110] and dotted lines show the present difference in emissions intensity between Fullsun HCPV and the local grid in the specified locations [108].

In Australia, for example, I find that Fullsun HCPV systems can be \$0.045/kWh more expensive than grid electricity whilst still remaining cost-competitive after an equivalent

carbon price of \$60/tCO_{2eq} proposed for 2020 is applied, but for Spain the HCPV systems must be within \$0.015/kWh of the grid price for the same to be true. Systems deployed in Phoenix would need to be less than \$0.03/kWh more expensive than the grid to compete in 2020, but this buffer increases to \$0.05/kWh in 2025 and \$0.09/kWh in 2030 as the carbon price increases. If a cost of carbon were to be introduced the geographic range of economically viable Fullsun systems would increase.

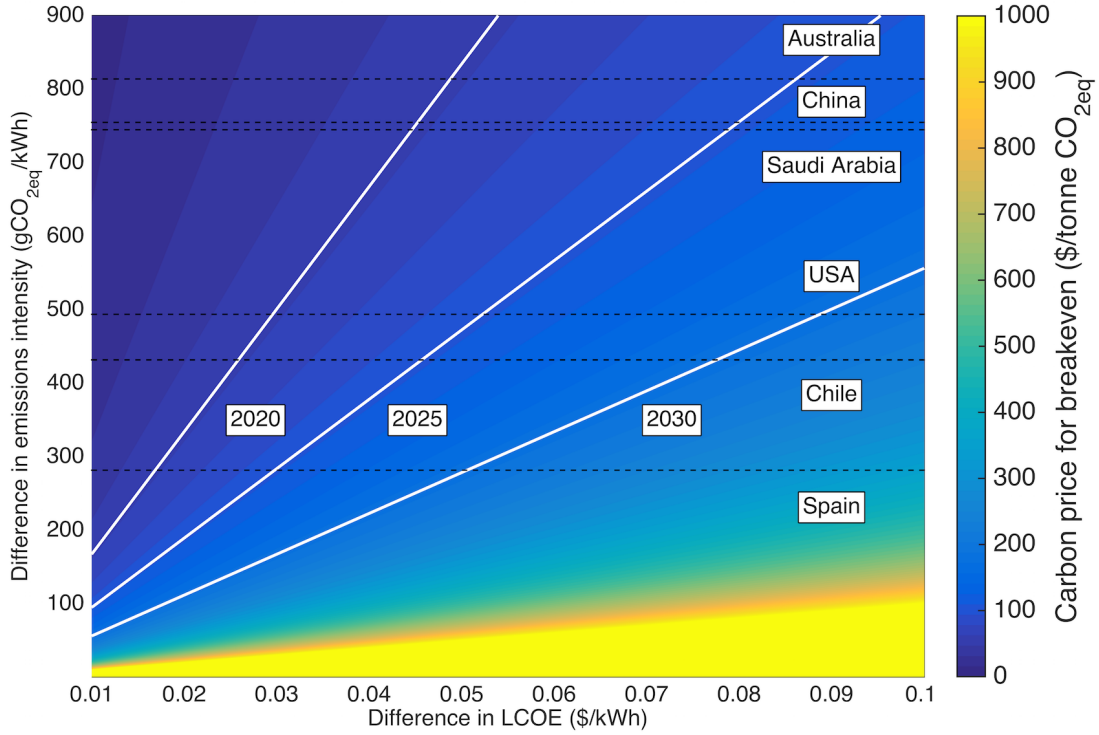


Fig. 4.9 The carbon price required (colour bar) for the LCOE of a high cost, low emissions technology to break even against comparison to a low cost, high emissions incumbent. The difference between the local grid emissions intensity and Fullsun HCPV systems (dashed black lines) is shown in addition to expected future carbon prices (white solid lines). From Sandwell et al. [163].

The financial benefit of providing energy with low emissions intensities could be instrumental in making Fullsun HCPV cost-competitive and, ultimately, a viable technology for future grid-scale installations. These calculations of equivalent carbon price hold true for any

renewable source which provides electricity at a lower emissions, but higher cost, than the local grid; this may mean that, despite having a lower emissions intensity than many sources, Fullsun HCPV may be outcompeted by cheaper renewable technologies. Although it appears to present a viable option for low-carbon generation, the economic competitiveness and deployability of Fullsun HCPV may depend on its ability to compete with other renewables and not just the incumbent grid network.

4.4 Conclusions

4.4.1 Summary of results

In this chapter I have used life cycle analysis to calculate the environmental impact of the Fullsun HCPV module. By accounting for the materials and processes used in its construction I found that each module has a CED of 355.3 MJ_{EPE} and 27.9 $kgCO_{2eq}$ are released before it leaves the factory. The greatest contributions to these values were from the metal frame and glass lens matrix; as both of these are structural components, this highlights the lightweight and low-profile design of the module. I found that the normalised module CED, 4.3 MJ/W_p, is lower than other values reported in the literature.

I also assessed the impact of systems using Fullsun modules in six example deployment locations around the world. I calculated EPBTs ranging from 0.22–0.33 years and CPBTs from 0.29–0.88 years; both metrics were dependent on the local DNI, but the additional impact of the local grid electricity means that the CPBT is more dependent on deployment location. I compared the emissions intensities of these Fullsun systems, between 6.5 and 9.8 gCO_{2eq}/kWh, with other renewable technologies. I found that Fullsun HCPV deployed in favourable locations can provide electricity with a lower environmental impact than other HCPV systems, conventional PV technologies, and other renewable options.

If the manufacturing costs can lowered to around \$1.10/W_p then Fullsun systems could achieved an LCOE below the SunShot Initiative target, but cost reductions of flat-plate PV may result in established technologies being more cost-effective. The viability of Fullsun systems may well be contingent on their economic performance compared to more mature PV technologies and, with the latter currently at a far lower cost, it may become increasingly difficult for Fullsun systems to establish enough installed capacity to reduce their manufacturing costs sufficiently.

By comparing the emissions intensity of Fullsun systems and the local grid networks I found that policies which would be equivalent to introducing a carbon price on electricity would incentivise the deployment of Fullsun systems. This could improve the competitiveness of Fullsun HCPV systems and increase the range of locations in which they could be economically deployed but would also benefit other renewables technologies, including mature PV systems.

4.4.2 The GHG mitigation potential of Fullsun HCPV

Systems using Fullsun HCPV modules have the potential to mitigate GHG emissions by providing electricity to the local grid network. As I have shown, the reduced materials requirements of the Fullsun modules present significant savings in terms of the embedded energy and GHGs per W_p of installed capacity compared to other HCPV systems and their resulting emissions intensities are lower than reported values for established PV technologies. The EPBTs and CPBTs of Fullsun systems are far lower than their expected lifetimes and, if the projected cost reductions can be obtained, their LCOEs will be low enough to be competitive with that of the grid.

The challenge for systems using Fullsun modules, and other HCPV technologies, will be their performance relative to established PV with which they will compete for the most favourable deployment locations. Mature PV technologies, and in particular c-Si, are

available at such low costs it may be impossible for Fullsun and other HCPV systems to compete for long enough to achieve the manufacturing innovations necessary reduce costs and provide an attractive return on investment. It may be that government policies incentivising extremely low emissions such as those offered by Fullsun systems will be necessary in securing the investment required for deployment. This would also benefit other PV technologies, albeit marginally less owing to their higher emissions intensities, but as both mature PV and HCPV would provide far lower emissions intensities than incumbent grid networks it is more likely that the lower-cost technology will be chosen for deployment, which at present is c-Si PV. Nonetheless, if Fullsun HCPV systems were to be deployed in suitable locations, they would provide an environmental benefit and mitigate GHG emissions from the national grid.

Chapter 5

Analysis of energy access in unelectrified villages in Uttar Pradesh

Acknowledgement of contributions

C Chambon and A Saraogi assisted in drafting the fieldwork survey. A Saraogi organised the logistics of performing the fieldwork, including selecting villages and liaising with local partners. P Sandwell, C Chambon, A Saraogi, A Chabenat and M Mazur conducted household interviews. Professional translation services were provided by M Khan and S Garg. N Ekins-Daukes and J Nelson advised on the direction of research and supervised the work. All other work is that of the author.

Previous presentation of this work

This work was previously published as an article in *Energy for Sustainable Development* [195]:

Sandwell P, Chambon C, Saraogi A, Chabenat A, Mazur M, Ekins-Daukes N, and Nelson, J. Analysis of energy access and impact of modern energy sources in unelectrified villages in Uttar Pradesh. *Energy Sustain. Dev.*. 2016; **35**: 67–79. DOI: 10.1016/j.esd.2016.09.002. Work from this article is reproduced with permission [112].

5.1 Introduction

5.1.1 Overview

Successfully transitioning from traditional to modern sources of energy relies on the satisfaction of the end users. Solutions must be functional, convenient and compatible with the requirements of the users and, by understanding these, it is possible to better inform their design [50]. The evidence and data used to inform the decision-making process is often sourced from national surveys and censuses which, whilst extensively detailed in terms of their breadth and geographic range, may not provide the best representation of, for example, the willingness and ability to pay for modern energy sources [41, 196]. There is a need for a greater understanding of the present situation of rural communities in the context of energy access that can be utilised by researchers and policymakers [196, 197] and the aim of this study is to provide this. I will add to this by outlining the potential of modern energy services to replace those currently available, the effect of meeting the aspirational desires of communities beyond lighting and phone charging only, and in chapters 6 and 7 demonstrate the impact of growing electricity demand as the rural economy develops.

In this chapter I will use the results of household surveys undertaken in communities in Bahraich District, Uttar Pradesh, India to assess the needs of rural populations and the subsequent requirements of energy systems which will provide them with electricity. As we have seen in chapter 3, the demand profiles used in simulation process can have an effect on the design of the system and it should be a high priority to ensure that the estimated load is representative of the needs of the community and relevant to their requirements. I use the survey data as an opportunity to do this and furthermore to estimate the benefits associated with mitigating the usage of kerosene lamps.

A graphical overview of this chapter is shown in fig. 5.1. In section 5.1 I present a brief summary of relevant literature to put this work in context. In section 5.2 I provide

a background to the household survey procedure, the region in which it was undertaken, and how I analysed the data we gathered. I also present a demographic overview of the demographics of the respondents, such as their household size and income, and an analysis of their daily activities. In section 5.3 I assess the ownership, usage and utilisation of different lighting sources and the effects of owning fixed lights on the use of kerosene lights. This allows us to establish a baseline of energy access and to calculate the potential benefits of mitigating kerosene lamps. In section 5.4 I describe the process of constructing device utilisation profiles and electricity demand profiles, then use them to quantify the demand of a village throughout the year using Monte Carlo simulations. I further investigate the effect of seasonal variability on the effectiveness of different electricity supply options and the impact on system design. Finally, in section 5.5, I summarise the findings of this chapter and assess the results in terms of designing and appraising suitable off-grid electricity systems for GHG mitigation.

5.1.2 Literature summary

Incumbent energy technologies used in rural India present significant problems for their users. Kerosene lamps, used widely around the world in areas without access to electricity, are expensive and inefficient to run, offer low luminosity, increase the risk of household fires and burns, emit significant quantities of GHGs, and produce hazardous indoor air pollution [39, 198–202]. Further issues are caused by the widespread usage of biomass for cooking, whose pollutants are known to cause bronchitis, heart disease, tuberculosis and asthma [203, 204] but are still widely used despite users being well-aware of their negative effects [197, 205, 206]. Many organisations are attempting to initiate a transition from these traditional energy sources to other cleaner and more modern sources but progress has been hampered owing to issues such as high initial costs, familiarity with incumbent sources, low awareness of superior options and poor utility [41, 196, 205, 207].

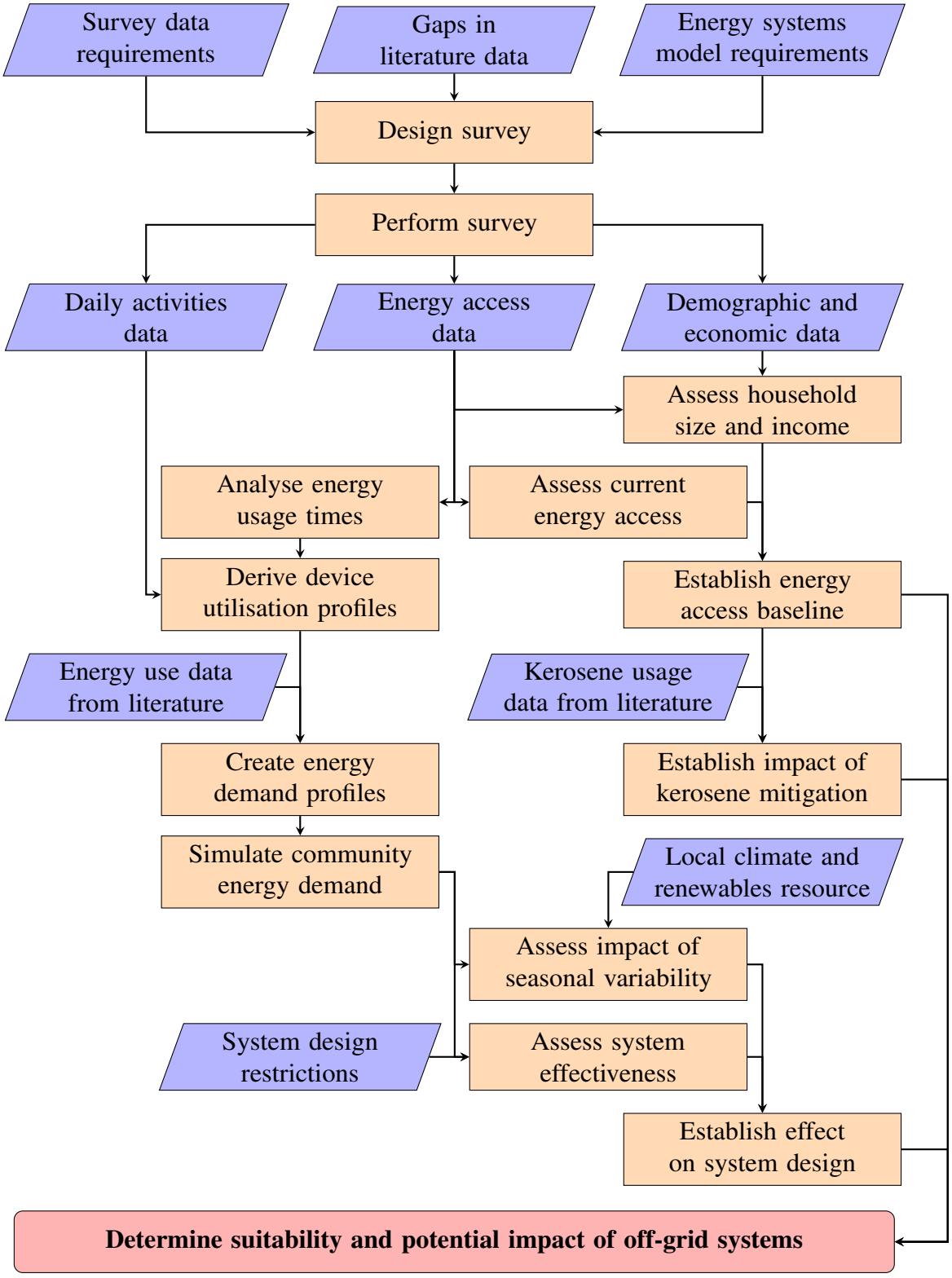


Fig. 5.1 Graphical overview of chapter 5.

A study by Howells et al. [40] described how discrepancies between the aims of government objectives and user preferences can retard the process of transitioning between technologies, whilst Sehjpal et al. [41] and Doig [196] report that with a given community or household several energy sources may be present. Despite this many studies assume that a complete and permanent transition will occur when a new technology is offered [208–210] which will be possible only if the requirements and desires of the end users are well understood and appropriately provided for. Hirmer and Cruickshank [50] argue that appreciating the value to the users is critical in securing a successful transition and the long-term success of an off-grid electricity system. Taking this into consideration we will explore the present situation of rural households to understand their current energy access and usage patterns, then use this to explore opportunities to provide electricity services which meet these needs.

Designing appropriate energy systems also requires a method of estimating electricity demand from the gathered data. Louie and Dauenhauer [73] reported that incorrect estimations of electricity loads can have significant impacts on the reliability and costs of electricity of off-grid PV systems; the use of static load profiles, common in many studies, may be susceptible to misestimating the needs of the community and therefore solutions designed using them may be inadequate in meeting the needs of the community. One solution to this is to extrapolate and predict the requirements of future energy infrastructure by monitoring systems already deployed, as demonstrated by Kobayakawa and Kandpal [86]. This may not be possible, however, in regions where such systems are rare or where detailed monitoring, which can be prohibitively expensive, has not been installed.

I choose to use the process described by Boait et al. [70] to statistically determine the demand of a community using a Monte Carlo simulation. As highlighted in their study, earlier work by McQueen et al. [99] verifies that this process is appropriate and accurate in its prediction of aggregate load demand in minigrid systems. This method will allow us to predict a representative estimate of the electricity requirements of communities in Bahraich

Table 5.1 Primary sources of lighting and cooking in Bahraich District (rural areas only), the state of Uttar Pradesh and India. Data from Ministry of Home Affairs, Government of India [55]. Adapted from Sandwell et al. [195].

Primary lighting type	Percentage of households		
	Bahraich District	Uttar Pradesh	India
Electricity	9.8	36.8	67.3
Kerosene	89.1	61.9	31.4
Solar	0.5	0.5	0.4
Other oil	0.2	0.3	0.2
Any other	0.2	0.3	0.2
No lighting	0.1	0.2	0.5

District by using locally-gathered data and without the need for long-term monitoring, which I will then use to evaluate the fitness for purpose of minigrid designs in this chapter and beyond.

5.2 Description of the study

5.2.1 Data gathering and analysis

Survey procedure

Uttar Pradesh is the most populous state in India and is home to the largest number of people without access to electricity in the country [37]. Bahraich District, with a population of around 3.5 million people [55], is typical of the northern regions of the state and the vast majority of its rural population are subsistence farmers. The inhabitants of this district rely heavily on kerosene lamps for their lighting needs [55], shown in table 5.1, in comparison to other households in Uttar Pradesh and all of India.

To gather data on the current levels of energy access of households in rural India we designed a survey; this was written by Philip Sandwell, Clementine Chambon and Amit Saraogi and is available in English in appendix C. The questions included were generally

closed and quantifiable, with the opportunity to elaborate or provide qualitative responses if necessary, and is divided into sections relating to demographic and socioeconomic indicators, daily activities, ownership and usage of energy devices, and costs relating to energy sources. The goals of the survey were to assess the present situation of households without electricity and understand how their needs could potentially be met via a community minigrid system, both academically and as market research for Oorja Development Solutions Ltd. These objectives were aligned but no conflict of interest was present between the academic goals of this research and the objectives of the company, and the analysis presented here was conducted independently of any commercial interests.

The survey was professionally translated into Hindi from its original English and the surveys were conducted in the household of the respondent in Hindi, through the use of an interpreter, with the responses relayed and recorded in English. Surveys were conducted by Philip Sandwell, Clementine Chambon, Amit Saraogi, Apolline Chabenat and Marek Mazur with translations and interpretation provided by Amit Saraogi, Marilyn Khan and Shweta Garg. The details and purpose of the study were explained to the respondent at the beginning as well as stating that they were free to not answer any question if they so chose. Written consent was collected from the respondent, or from a family member on their behalf if they were illiterate, for their participation in the study.

Performing household interviews such as those used in this study allows the potential beneficiaries of an energy system to provide an input into its design and specifications. Involving the community directly allows them to express their desires for the system rather than rely on the assumptions of a minigrid developer or government agency, for example, which may not be reflective of their true needs. Gathering data in this way can help increase social equity by providing a voice to rural communities who may otherwise be only recipients of energy systems, rather than co-designers, and will help ensure their long-term sustainability by increasing their utility and better alleviating the poverty of the people that will use them.

We chose rural villages in Bahraich District which had not been connected to the grid as the focal points of our surveys which took place in May 2015. Several villages were selected by a local guide, who had previously worked in the district as a government administrator for the region, as a reflective sample of typical unelectrified villages. These communities were also visited as potential candidates for the pilot location for the first minigrid to be deployed by Oorja Development Solutions Ltd. and, as before, there were no conflicts of interest between the academic research being undertaken and the commercial objectives of the company.

After arriving at a village the team met with the local leaders to explain the aims and objectives of the survey, and the leaders suggested households for interview which would be typical of the village as a starting point. Interviews typically lasted between 20 and 40 minutes and, if possible, women were prioritised as respondents to give a more accurate representation of the energy use in the households [197, 211, 212]. In total 51 households were surveyed and represent a total population of 553 people. Where relevant, questions pertaining to the times at which daily activities or energy usage occurs were phrased to ask about the previous day and the most recent occurrence for questions about income and expenditure. The aim of this was to allow the respondent to give an accurate response to a specific event, rather than suggesting they provide an estimate or average which may not less reliable. Gender biases were apparent during the survey procedure: for example, male respondents provided responses about farming inputs with greater confidence than those about cooking practices, and the reverse was true for female respondents.

During the analysis process any unreliable data, for example with significant differences between reported device usage and corresponding fuel expenditure or between reported incomes and outgoings, was omitted from further investigation. The majority of respondents were comfortable in answering all of the questions and no question had more than 5% of

responses omitted. Unless otherwise stated, the averages calculated for each parameter is the mean value with its associated standard error.

The results of this survey will be applicable to the situation of many rural villages in Bahraich District and the state of Uttar Pradesh. The situation described in this chapter is likely to be reflective of many communities around India but the data we have gathered, for example on income and device ownership and usage, will be specific to the district and region we performed the fieldwork in. For this reason in this chapter and beyond I do not generalise my analysis to the wider national context of India, for example, but instead consider an community representative of those in which the fieldwork was performed. This analysis could be built upon and extended to national context of India in order to provide policy recommendations, for example, but this is beyond the scope of my analysis. Whilst many of the issues will be common across India and around the world, for example rural poverty and reliance upon kerosene lamps, the data I present in this chapter should be taken to be specific to Bahraich District or, potentially, other similar regions of rural Uttar Pradesh.

Oorja: Empowering Rural Communities

Oorja Development Solutions Ltd. is a for-profit social enterprise, founded in August 2014 by Clementine Chambon and Amit Saraogi, which aims to provide rural communities with reliable electricity. The company is developing minigrid systems powered by PV and biomass to supply domestic and productive power to communities in Uttar Pradesh, India.

In June 2017 Oorja inaugurated their first 4 kW community PV minigrid in Sarvantara, a village in northern Bahraich District, which was installed by BOS-AG and partially financed by the Grantham Institute, Imperial College London [213]. Four fixed lights and phone charging are available on the most basic tariff of INR 130 per month, with fans available on a higher tariff.

Analysis of time-dependent data

Understanding the usage times of energy devices is important in providing a reliable electricity service. For this reason we aimed to capture the time dependence by asking respondents the times at which they used their devices which allows us to build temporal profiles of electricity service demand by averaging survey responses and synthesising load profiles. The nomenclature used in this section is the same as that used in chapter 7 where the processes outlined here are expanded upon.

We asked respondents the number of devices they used during each hour of the day on the day before the survey was taken . We recorded this number as D_H^{ij} for a device type i in surveyed household j, which owns a total N^{ij} devices of that type, and for the hour of the day $H \in \mathbb{Z} : H \in [0,23]$. By considering all of the households surveyed we can aggregate all of the devices that are in use at a given time, D_H^i, and the total owned by all of the community, N^i, which are given by

$$D_H^i = \sum_j D_H^{ij} \tag{5.2.1}$$

and

$$N^i = \sum_j N^{ij} \tag{5.2.2}$$

For a total number of households surveyed, $C_{\text{tot}} = \max(j)$, the average ownership n^i per household of a device i is

$$n^i = \frac{N^i}{C_{\text{tot}}} \tag{5.2.3}$$

which can be used to assess the relative popularity of different devices amongst the community. The average number of devices in use per household at a given time, d_H^i, reflects both the usage and ownership of devices and is calculated by

$$d_H^i = \frac{D_H^i}{C_{\text{tot}}} \tag{5.2.4}$$

but does not fully capture the demand for energy services. To evaluate this we use the utilisation of a device which is the probability that a device is in use at a certain time, given that a household has access to it. Some devices will have a lower utilisation at certain times and higher at others, for example lights at midday and in the evening respectively. The utilisation of a device, $u_H^i \in [0,1]$, is calculated by

$$u_H^i = \frac{D_H^i}{N^i} \tag{5.2.5}$$

which allows us to also calculate the total number of hours that a device is used per day on average, U^i, using

$$U^i = \sum_{H=0}^{23} u_H^i \tag{5.2.6}$$

which can be used, for example, to estimate the total daily demand for that energy service.

By analysing the survey results and converting them into utilisation profiles I am able to use the process described by Boait et al. [70] to synthesis demand profiles from the statistical data. Similarly to their work, I will use the survey data as inputs in a Monte Carlo simulation to predict the total electricity demand of a community. This process is expanded upon and explained in greater detail in section 6.3. The codes used to generate the results in this chapter are given in appendix B.

Owing to the large number of devices recorded as part of the study the mathematical standard error for each utilisation profile is small. These values should be treated with appropriate caution, however. For lighting, for example, the error from respondents reporting the wrong times of usage is likely to be small during the day and the evening when the status of the lamp is clear, but at dawn and dusk this may not be the case as the exact times of use are not accurately known. For this reason I suggest that an absolute error of $\pm 10\%$ for utilisation in twilight periods which would represent 10% of respondents misremembering the times of device usage by one hour earlier or later than the actual time.

5.2.2 Respondent demographics

Household size

Respondents were asked about their homes and family members both to obtain demographic data and to introduce them to survey procedure. The size of the respondent's primary dwelling was quantified by the number of rooms which could be made of any material, but in general were made of brick, concrete, mud, wood, or a combination of these. Most were roofed with thatch, brick or concrete and had mud or cement flooring.

A cumulative distribution function (CDF) of the number of rooms in the dwellings surveyed is shown in fig. 5.2 a) in comparison to all of Uttar Pradesh. The average number of rooms per dwelling, at 3.2 ± 0.3, is larger than the average for the state and may be a result of the greater amount of space available in the rural villages in comparison to more densely populated urban areas.

The occupancy of the household is defined as the number of people who are primarily resident in there and the average was found to be 10.8 ± 0.9 people per dwelling. To account for the variation in dwelling sizes a CDF of occupancy per room is shown in fig. 5.2 b) with the average calculated to be 4.2 ± 0.4, greater than the statewide average of 2.4 occupants per room which can be estimated from census data [55].

Despite a larger dwelling sizes than the average for Uttar Pradesh the larger family size results in a greater occupancy per room and the majority of households surveyed were home to more than one married couple in addition to their parents and children. This could be a result of the fact that most families rely on subsistence farming on inherited land, limiting opportunities to move away, but as analysing the social drivers behind this effect is beyond the scope of this work it will not be investigated further.

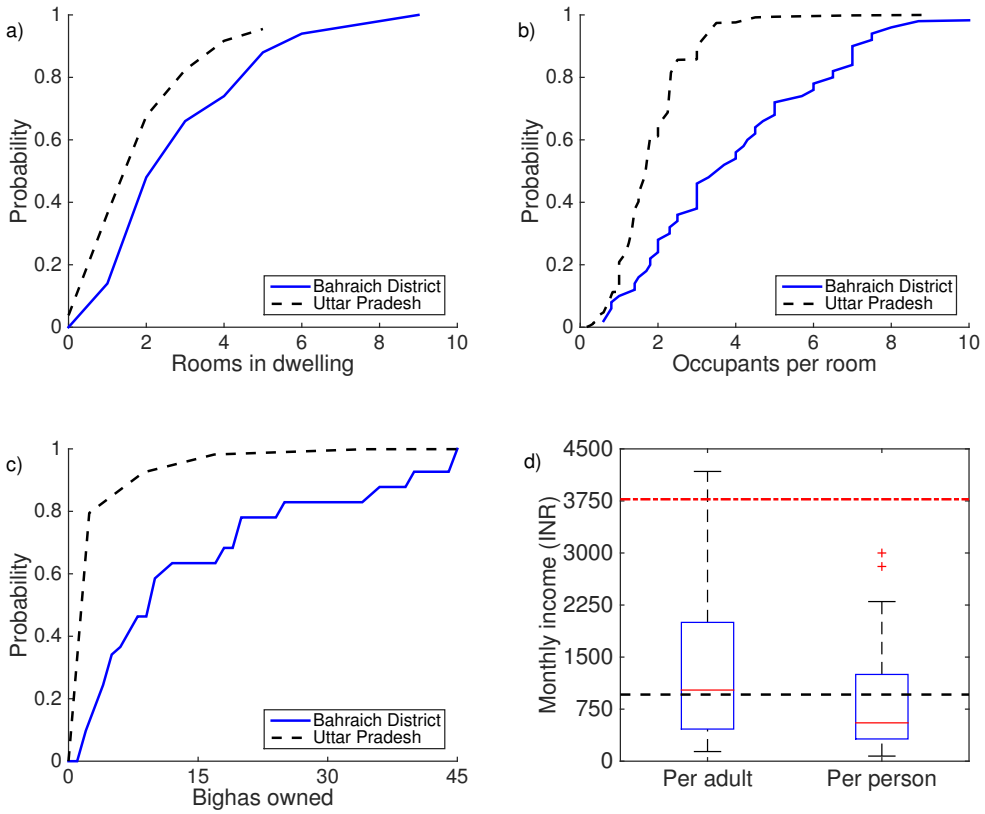


Fig. 5.2 Cumulative distributions of the number of a) rooms in a dwelling, b) occupants in a household and c) bighas of land owned, and d) box plots of monthly income. Data for Uttar Pradesh from Ministry of Home Affairs, Government of India (2011) [55] plotted in available ranges. Red dot-dashed line represents $1.25 per day, the World Bank definition of poverty[214]; black dashed line represents INR 32 per day, the Indian Government definition of poverty in rural areas [215]. From Sandwell et al. [195].

Table 5.2 Livestock ownership by animal species of the households surveyed. Adapted from Sandwell et al. [195].

Animals owned	Percentage of households			
	Buffalo	Cow	Goat	Bull
0	20.9	72.1	83.7	93.0
1	44.2	20.9	7.0	-
2	18.6	2.3	2.3	7.0
3	7.0	4.7	2.3	-
4	4.7	-	2.3	-
5	-	-	2.3	-
More than 5	4.7	-	-	-

Farmland ownership

With subsistence farming as the most common primary occupation, 91% of respondent households owned their own farmland and a further 5% rented it from others. There are two growing seasons, *kharif* for rice and maize from July to October and *rabi* for wheat from October to March, which make up the majority of agricultural production with smaller amounts of cash crops such as vegetables and pulses grown during interseason periods.

Respondents were asked how much land they owned in the units of *bigha* which, under the local usage, is defined as 2.5 *bighas* to one hectare. The CDF of land ownership is plotted in fig. 5.2 c) with the average ownership found to be 17.3 ± 3.4 *bighas* per household, or 2.0 ± 0.4 *bighas* per person. Land ownership in Bahraich District was found to be larger than elsewhere in Uttar Pradesh [216], possibly as a result of the remoteness of the villages providing a greater area to farm and of larger household sizes aggregating farmland to provide for a greater number of people.

Livestock was kept by 91% of households to provide agricultural labour and milk for self-consumption or sale, with a breakdown given in table 5.2. Animals were not kept for meat as all of the villages surveyed had a Hindu-majority religious makeup.

Household income

The monthly income of most of the respondents was highly seasonal, a reflection of their reliance on subsistence farming and daily labour. Some respondents were less forthcoming about financial details than others, either from not knowing their total income or from declining to answer the relevant questions. Where appropriate I calculated annual incomes based on the agricultural yields reported by respondents and local market prices of their crops from which I derived a monthly equivalent.

Box plots of monthly income per adult and per person (including children) are shown in fig. 5.2 d). The average reported monthly income per household was INR 7900 $\pm$ 1670, with averages per adult and per person of INR 1510 $\pm$ 215 and INR 860 $\pm$ 125 respectively. Under the definition used by the World Bank of \$1.25 per day, 21.3% of people in India live in poverty [214]; my results suggest that all but the wealthiest respondents live below the poverty line, displayed as a red dot-dashed line on fig. 5.2 d). The figure of INR 32 per day used by the Indian Government for rural areas [215], shown as a black dashed line, suggests that by this definition two thirds of the households surveyed live in poverty. This is more than twice than the average for rural Uttar Pradesh, reported to be 30.4% [217]. Many respondents expressed that the seasonal nature of their low income meant that they were unable to save money for the future.

Daily activities

Respondents were asked about their activities during the previous day which were divided into seven categories: sleeping, working of any kind, cooking and eating, reading and studying, socialising with family and friends, travelling, and any other activity. If a respondent participated in more than one activity during an hour of the day then the one with the majority or plurality of time spent was recorded. The responses are displayed in fig. 5.3 as a

proportional cumulative bar chart of all responses (top), segregated by activity type (bottom), and as an average fraction of the day (right).

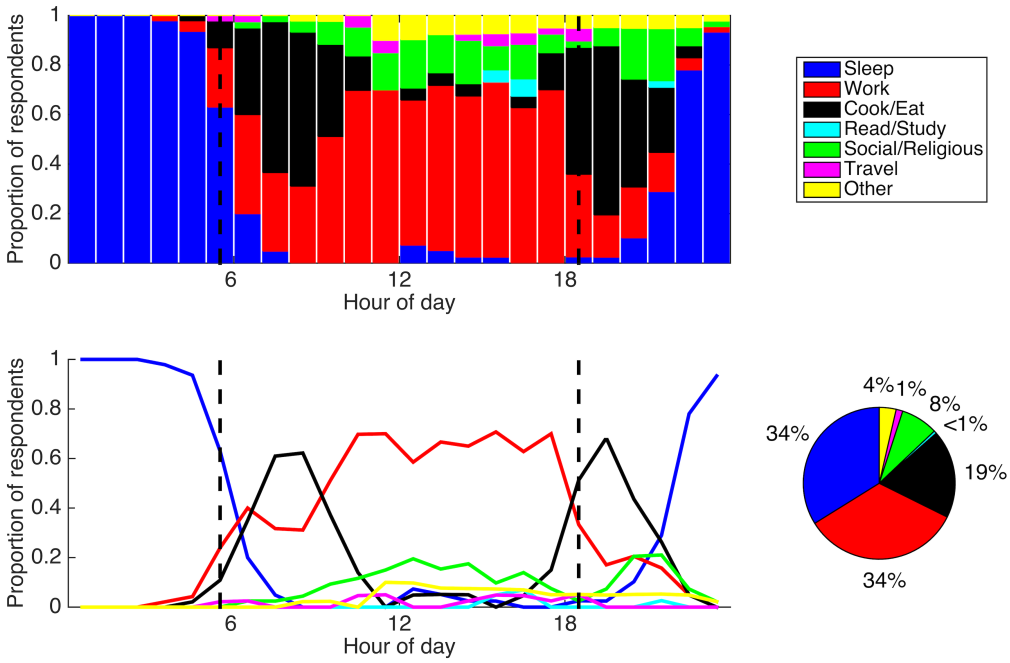


Fig. 5.3 Daily activities of respondents. Black dashed lines represent approximate times of sunrise and sunset. From Sandwell et al. [195].

Around eight hours per day is spent sleeping and a similar amount of time is spent working, generally either in farming or household chores. Respondents reported spending over four hours per day preparing and eating meals which is a reflection of the fact that where possible women, who traditionally bear most of this responsibility, were interviewed.

An anticorrelation between working and cooking is seen in fig. 5.3 which suggests a competition between the two activities. If time spent on the latter could be reduced, for example by using improved cookstoves which would reduce cooking times and also the burden of collecting firewood, classified here as work, then more time could be dedicated to productive or social activities. Respondents spent less than 10% of their time socialising with their family and friends and expressed a desire to spend more time helping their children to study as a priority for their wellbeing.

Table 5.3 Lamp ownership of the households surveyed. Adapted from Sandwell et al. [195].

Lamps owned	Percentage of households		
	Kerosene	Fixed	Torch
0	13.7	80.4	35.3
1	13.7	2.0	33.3
2	21.6	7.8	19.6
3	17.6	2.0	7.8
4	15.7	-	2.0
5	7.8	2.0	2.0
More than 5	9.8	5.9	-

The approximate times of sunrise and sunset are displayed on fig. 5.3 as vertical dashed lines and show a clear reliance on daylight for working. Access to electricity for lighting can provide the flexibility and freedom to choose when to perform different activities [50, 211] and addressing this would tangible impact on the lives of people in rural communities.

5.3 Analysis of energy access

5.3.1 Energy for lighting

Lighting ownership

We asked the respondents which types of lamps, and how many of each, they had access to in their household. These were categorised as three types: kerosene lamps, which were almost always wick lamps; fixed lights, defined to be any electric light permanently attached to a wall or ceiling of the dwelling; and torches, that were any handheld portable electric lamp powered by batteries. We found ownership of solar lamps to be negligibly small and candles, whilst owned by many households, were used only rarely when all other sources of light were unavailable; for these reasons I omit them from further consideration. A breakdown of the ownership of kerosene lamps, fixed lamps and torches is available in table 5.3.

More than 80% of households are primarily reliant on kerosene lamps for lighting in their household; of these, the average ownership was 3.4 ± 0.3 kerosene lamps. I found this to loosely correlate with the number of rooms in the dwelling at 1.3 ± 0.1 lamps per room, which reflects the fact that the low luminosity of kerosene lamps means that several are needed to provide adequate lighting [39, 201].

Fixed lights were typically comprised of LED bulbs connected to a PV panel and battery storage forming a solar home system, although these components were generally not part of a prepackaged commercial bundle. I found an average of 0.9 ± 0.1 fixed lights per room in households with access to them which suggests, unlike for kerosene lamps, that one bulb is adequate in providing sufficient illumination for the needs of a user in the room. Torches were used rarely for lighting rooms but instead were shared between family members and used when travelling around the village at night or when tending to animals.

Lighting usage

The usage of lamps is very time-sensitive and so understanding the patterns of lighting demand is important in providing a useful electricity service. I quantify lighting usage in three ways, shown in fig. 5.4: a) the average number of lamps in use over time per household, b) the utilisation of lamps over time, given that one is owned, and c) the total number of hours that a lamp is used per day.

At the peak times of 19.00–20.00 almost all kerosene lamps are in use, as respondents stated a desire to keep at least one lamp lit in each room during the evening when they were awake, but afterwards there is a sharp decline. A small number are in use throughout the night which respondents stated was motivated for security, comforting children, or cultural reasons. This can, however, increase the risk of fire in the household.

Fewer households own fixed lights which reduces their prominence in fig. 5.4 a). This is not the case for their utilisation in fig. 5.4 b): whereas kerosene lamp utilisation declines

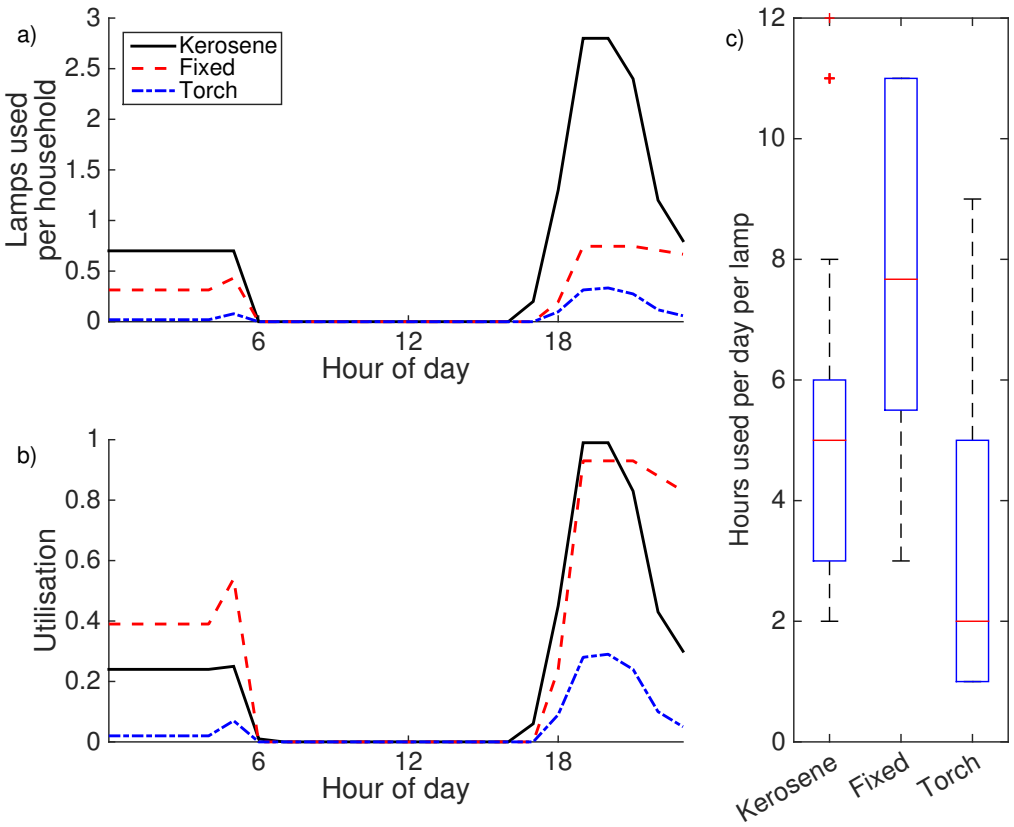


Fig. 5.4 a) Number of lamps being used per household, b) utilisation of lamps, and c) boxplots of the number of hours per day each type of lamp is used. From Sandwell et al. [195].

after 20.00, fixed light utilisation remains high until 23.00. Furthermore a greater proportion of fixed lights are left lit overnight and there is a morning peak at around 5.00 which is far more prominent than for kerosene lamps. Overall the average usage is 30% higher for fixed lights compared to kerosene lamps, which is shown by their total usage per day per lamp in fig. 5.4 c). Unlike kerosene lamps which burn fuel in proportion to their usage, there is no financial restriction to using fixed lights and, assuming the battery of the system allows for it, for keeping them lit throughout the night.

Torches are not generally used to light rooms but are a necessary requirement for rural households. Torch usage peaks around dawn and dusk as people travel around the village before sunrise and after sunset, shown in fig. 5.4, but typically are used for only a few hours per day. Battery-powered torches would not normally be charged from an electricity system, although this would be possible if special models were introduced, and their usage could be decreased if adequate community street lighting were provided.

Effects of fixed lighting on kerosene usage

One can infer the effects of transitioning from kerosene lamp usage to fixed light usage by comparing the use of the former by respondents with and without access to the latter. The kerosene lamp usage in households with and without fixed lights is displayed in table 5.4. Despite both having access to both, households with fixed lights do not show a significant decrease in kerosene lamp usage; instead, we observe a marginal increase in the cumulative number of hours per day that kerosene lamps are used. The larger error value around the mean of the cumulative total is caused by the fact that some households reduced their kerosene usage to nearly zero whilst others seemingly treated all of their lighting options in the same way, using kerosene for longer in the same way they used fixed lights.

The recurring costs of an electric home lighting system are minimal, if any, and some respondents reported using previous systems until they failed and were planning to buy

Table 5.4 Kerosene lamp usage in households with and without access to fixed lights. Adapted from Sandwell et al. [195].

	Household type	
	Kerosene only	With fixed lights
Kerosene lamps per household	3.4 ± 0.3	1.3 ± 0.4
Average kerosene lamp usage (hours/day)	5.3 ± 0.5	7.3 ± 1.4
Cumulative kerosene lamp usage (hours/day)	19.0 ± 2.6	19.3 ± 3.6

replacements when they were able. It may be that some households with fixed lights reduced their kerosene consumption and channelled most of the money they were previously spending on fuel towards other purposes, and others chose instead to continue buying the same amount kerosene as an additional source of lighting to augment the fixed lights and using the two simultaneously. The former case would an example of a partial rebound effect, where a new technology fails to completely offset the usage of a previous one, but still has a positive effect; the latter would be an example of a backfire, where the new technology fails to replace the negative effects of the incumbent or even makes its effects worse.

Many organisations aim to provide electric lighting to communities in order to offset or eliminate the use of kerosene lamps. My analysis suggests that providing fixed lights alone will not necessary achieve this and that other measures must also be used in conjunction to reduce the amount of kerosene lighting used. This could include, for example, providing more fixed lights to illuminate every room in a dwelling and ensuring the electricity service that is provided is reliable and affordable enough to offset expenditure on kerosene.

Benefits of mitigating kerosene use

When discussing lighting options with respondents we found that almost all of those primarily reliant on kerosene expressed a desire for electric lighting and were well aware of the negative aspects of kerosene lamps, in particular the poor quality of light and pollution. In order to calculate the tangible savings that can be made both financially and environmentally

Table 5.5 Data used to calculate the costs and GHG emissions associated with kerosene lighting for households with no other source. Values from this work and Mahapatra et al. [201]. Adapted from Sandwell et al. [195].

Household information	Occupants	10.6	This work
	Kerosene lamps	3.4	This work
	Total lamp usage (hours/day)	19.0	This work
	Monthly kerosene expenditure (INR)	211	This work
Lamp information	Efficiency (ml/hour)	21.6	[201]
	Luminosity (k-lumens)	0.076	[201]
	Lifetime cost (INR/lamp)	4,769	[201] & this work

by switching from kerosene lamps to fixed lights we asked respondents about their fuel purchasing habits. On average I calculated that households used 6.1 ± 0.8 l of kerosene per month, similar to findings by Lam et al. [218] in a national-level study on kerosene subsidies, and spent an average of INR 211 ± 31; this expenditure is similar, albeit slightly higher, than the average found by Urpelainen [219] in a study published in 2016 also assessing energy poverty in Uttar Pradesh. Respondents stated that government subsidies at the time the survey was taken allowed households to purchase two litres of kerosene at a reduced rate of INR 20 per litre, with each subsequent litre costing around INR 50.

I use the results of Mahapatra et al. [201] to assess the cost and emissions associated with the use of kerosene lamps. By integrating these reported results with the data from the survey I am able to calculate the cost and GHG emissions of an "average" household in rural Bahraich District with access to only kerosene lamps for lighting. These assumptions used in these calculations are shown in table 5.5 and the results are shown in table 5.6. The lifetime impact is calculated using the same process as in Mahapatra et al. [201] but with cost, demographic and usage data from this work. The GHG emissions of a kerosene lamp varies dependent on a number of factors, but the value of 0.055 $kgCO_{2eq}$ per hour used by Mahapatra et al. [201] is similar to or lower than that of several other studies [220–222].

I find that the average household spends INR 3243 per year on kerosene lighting and emits 381.1 $kgCO_{2eq}$ as a result. By considering its luminosity we can calculate the impact of the

Table 5.6 The costs and GHG emissions associated with kerosene lighting for households with no other source. *: Representative values from Mahapatra et al. [201]. a: No emissions during use, i.e. not including embedded GHG emissions from system deployment. b: Biomass input from a renewable source not leading to deforestation. Adapted from Sandwell et al. [195].

	Cost (INR)	GHG ($kgCO_{2eq}$)
Impact of kerosene lamps		
Per lamp per day	2.5	0.3
Per household per year	3,243	381.1
Per capita per year	300.3	35.3
Per hour of light	0.48	0.055 [201]
Per k-lumen-hour	6.5	0.72
Electricity from PV *		
Per k-lumen-hour	1.5	– [a]
Electricity from biomass gasifier *		
Per k-lumen-hour	0.26	7×10^{-5} [b]

lamp in terms of its useful output: at a cost of INR 6.5 per k-lumen-hour the expense of using kerosene lamps is more than three times higher than for typical domestic lighting systems supplied by PV or biogas, which also have negligible emissions during their usage [201]. From section 3.3.1, a PV and storage system with an emissions intensity of 487 gCO_{2eq}/kWh and LCUE of $0.53/kWh, using a 3 W LED light [35] with a luminosity of 120 lumens [223], would have an impact of 0.012 $kgCO_{2eq}$ per k-lumen-hour at a cost of INR 0.85 per k-lumen-hour. The latter figure is lower than the calculation given by Mahapatra et al. [201] owing to cost reductions in off-grid PV systems and improvements in the performance of LED lamps. As part of this study I also used a similar process to investigate the impact of using modern stoves in comparison to traditional stoves for cooking meals; more information is given in the box below and in Sandwell et al. [195].

Energy access for cooking and the impact of using gas stoves

We asked respondents about the stoves they owned and used and collected data similar to that for lighting. We found that two types of stoves were used: traditional *chula* stoves which burned firewood, cattle dung or other biomass, and modern stoves powered by liquified petroleum gas (LPG). Most households owned either one or two stoves of either kind, with the majority primarily reliant on traditional stoves. We found that many respondents without an LPG stove expressed a desire for one to reduce cooking times, which was also found by Rouse (2002) [197].

By comparing households with access to LPG stoves and those without, I calculate that those with access spend 17% more in meeting their cooking needs but their GHG emissions were 28% lower. As with the transition from kerosene lamps to fixed lights, many households with access to both stoves continued using traditional stoves rather than switch entirely. A more detailed analysis, comparable to that found in section 5.3, is available in Sandwell et al. [195].

5.3.2 Access to modern energy

Solar photovoltaics and batteries

None of the respondents we interviewed had access to a grid connection but a sizeable minority had independently invested in an improvised solar home system. Of the surveyed households 18% owned a PV panel and battery, whilst 6% had the former only and 4% the latter only, which were charged at the local marketplace. These devices were used to power the fixed lights discussed earlier and charge cell phones, but few households owned other electrical devices such as fans or, more rarely, televisions.

We found the PV panels used by respondents were one of two typical sizes, 75 W or 150 W, and reportedly cost between INR 2500 and INR 12500 depending on their size and

when they were purchased. Respondents bought batteries for around INR 5500 and were told they had a guarantee for between three and five years, depending on where they were purchased, and could be serviced at a cost of INR 100 per year. Respondents that had owned batteries for several years did not identify any degradation that was significant enough to limit their usage of electricity, such as a gradual reduction in the amount of time they could use their fixed lights, but some reported that the voltage was too low to use both lights and fans simultaneously.

Cell phone ownership

We found that over 90% of households owned at least one cell phone. The average ownership was calculated to be 2.2 ± 0.2 per household and 0.5 ± 0.1 phones per adult, which is reflective of a married couple sharing one device, and respondents highlighted cell phone charging as a high priority after lighting. Those who owned PV panels and batteries would charge their phones within their households and those without would rely on their family or neighbours to charge their phones or do so at the local market. Most respondents said that their phones took between two and three hours to charge and this was generally done two or three times per week. Charging a cell phone would typically cost INR 5 per charge.

Access to the electricity grid

Although none of the respondents had access to a grid connection, several respondents shared with us qualitative information about their friends and relatives living in villages which were connected to the national network. Their opinions were varied: many admired the convenience and sense of modernity that a grid connection offered but were critical of its unreliability. Anecdotally around eight hours of power was typically available per day but this was at random and no warning was given about blackouts. Jain et al. [52] reported a similar situation in which 95% of households with a grid connection received three hours or

less of power per evening and the most common complaints were the duration and reliability of service.

Respondents in the survey, when asked explicitly, said that they would be willing to pay a higher price for electricity if the service were reliable even if the total number of hours of electricity service were lower compared to the grid. This willingness to pay a price premium for access to reliable electricity could therefore represent an exploitable business proposition for off-grid systems which are optimised for reliability, even if their cost is greater than that of grid power.

Facilitating energy access

A lack of disposable income and opportunities to save is a barrier that households reported which prevented them from investing in a solar home system. Modern sources of electricity can be cheaper and more environmentally responsible but rely on an upfront cost that is unattainable to many below the poverty line, which we have found most of the respondents were. Accessible and effective renewable energy financing schemes could help with this: previous work by Jain et al. [52] reported that 51% of rural households would be in favour of replacing existing government kerosene subsidies with support for minigrids instead, and 90% would support the subsidy being put towards solar lanterns. This previous research and the views of the respondents in this survey suggests that there is the support within the communities for replacing kerosene lamps with superior alternatives, but to do so the replacement technologies must provide enough of a benefit to avoid a continued reliance on kerosene lamps and financial and legislative support mechanisms must be in place to ensure that the technical systems I investigate are viable and practical.

5.4 Sizing a village electricity system

5.4.1 Estimating electricity demand

Constructing an electricity demand profile

Understanding the electricity demand of an off-grid community is critical in providing reliable energy, particularly for systems supplied by renewable energy. Here I incorporate the data gathered in this survey to create a representative demand profile throughout the year of an off-grid community in Bahraich District. This process is expanded on and explained in greater detail in section 6.3.

I interpret the utilisation of a device as the probability that it will be used, given that it exists. Considering fixed lights shown in fig. 5.4 b) we observe four distinct periods of utilisation: before dawn, when lights are left on overnight; a morning peak, when people wake up but before the sun rises; during the day, when lights are not necessary; and the evening peak, after night falls and when people have the greatest desire for lighting. These utilisation periods can be associated to the time periods of the day: early morning darkness, pre-dawn twilight, daytime, post-sunset twilight and evening darkness. I assume that the morning peak is related to the time of sunrise which is when most respondents woke up, also suggested by fig. 5.3, and that the evening peak begins at sunset. I assume that the time of the end of the evening peak is constant.

By taking the proportion of time of each hour of the day composed of night, day and twilight periods at the time of year that the survey was taken, and comparing this to the

utilisation reported by the respondents, I found that

$$u_H^{iM} = \begin{cases} 0.39 & \text{for } H \in \xi_m^M \\ 0.93 & \text{for } H \in \xi_t^M \\ 0.00 & \text{for } H \in \xi_d^M \\ 0.93 & \text{for } H \in \xi_e^M \end{cases} \tag{5.4.1}$$

where u_H^{iM} is the utilisation of device i, in this case fixed lights, in hour H of month of the year M, and $\xi_m^M, \xi_t^M, \xi_d^M and \xi_e^M$ are the set containing hours of morning darkness, twilight, daytime and evening peak times respectively, again in month M. I found no difference in utilisation between periods of morning and evening twilight and evening darkness, suggesting respondents would use fixed lights whenever it was dark outside.

I extrapolated these utilisation factors to every month of the year by considering the proportional composition of each hour of the day for the mid-month day. This is most relevant for calculating the utilisation during the morning from 4.00–6.00 and in the evening from 17.00–19.00, with the two extremal examples of June and December shown in table 5.7.

A similar process was used to calculate the energy demand from households charging cell phones. I inferred the number of hours that a respondent typically spent awake from the data presented in fig. 5.3 and the time of sunrise, with the times at which respondents woke up being well described by a normal distribution. I derived the probability that a phone would begin being charged in a given hour of the day from the probability that a person was awake and normalised such the total probability is equal to two-sevenths, corresponding to two charges per week. Finally I calculate the probability that a phone was being charged in a given hour of the day, which here becomes the utilisation of phone charging, as the sum of the probability that the phone began charging in that hour plus the sum of the probabilities of the two preceding hours. This sums to a total of three hours per phone per charge, at a rate of

Table 5.7 Example utilisation of fixed lights during morning and evening hours in June and December, derived from the proportions of each day period that makes up each hour.

Hour of day	Day period	June		December	
		Minutes	Utilisation	Minutes	Utilisation
	Night	41		60	
4.00	Twilight	19	0.56	0	0.39
	Day	0		0	
	Night	0		59	
5.00	Twilight	8	0.12	1	0.39
	Day	52		0	
	Night	0		20	
6.00	Twilight	0	0.00	26	0.53
	Day	60		14	
	Night	0		23	
17.00	Twilight	0	0.00	26	0.76
	Day	60		11	
	Night	0		60	
18.00	Twilight	2	0.03	0	0.93
	Day	58		0	
	Night	33		60	
19.00	Twilight	27	0.93	0	0.93
	Day	0		0	

twice per week. In addition three hours of charging at a standby power demand was included to represent a marginal power use if users left their phones charging longer than necessary. More than three hours was included if the phones became fully charged overnight and the user was not awake to disconnect it from the power supply.

I derived utilisation profiles for fixed lights and cell phone charging from the data gathered in this survey which form the basis of basic electricity access which would meet the needs of a newly electrified village [56]. I further include devices such as televisions, radios, fans and refrigerators using utilisation profiles taken from Sen and Bhattacharyya [59] to represent a community with a greater level of energy access, perhaps at a later stage of economic development. I consider these two cases to form 'Basic' and 'Aspirational' demand profiles.

Simulating the demand of a village

Using the method described by Boait et al. [70] I use the data from the surveys in a Monte Carlo simulation which evaluates the electricity demand of the community. The utilisation of each device is used as the binomial probability that a device is in use at a given hour of the day, and can vary from month to month. I calculated the total number of devices available to the community from the average household ownership found in this work, by the most recent Census of India in 2011 [55], and in other similar studies [59, 224]. I use indicative values of the electricity consumption of devices which offer both low power demand and high quality of service which would be suitable for rural electricity systems [35, 223].

The Monte Carlo simulation uses a binomial probability distribution, for each device type at each hour of each month, composed of the utilisation as the probability of success and the total number of devices in the community as the number of trials, with the latter being calculated as the product of the average ownership per household and the number of households in the community. The number of successes is drawn at random from this distribution, representing the number of devices in use, and is multiplied by the power rating

of the device to calculate the total power demand during that hour. I assume a community size of 100 households and perform 10,000 samples for each month of the year; an overview of the data used in the simulation is given in table 5.8. A similar process is used to generate long-term load profiles and is explained in more detail in section 6.3.

I consider two types of demand profiles: 'Basic', composed of lighting and phone charging services, and 'Aspirational', which additionally includes entertainment and comfort options such as televisions, radios, fans and refrigerators. I assume that the utilisation of televisions and radios would be lowest during the day and higher in the evening, and fans are used mainly during the hottest parts of the daytime and more modestly during the night. The duty cycle of refrigerators is assumed to be constant throughout the day.

The power demand profiles for an average household in June and December are shown in fig. 5.5. The 'Basic' load profile is greater in December, owing to longer periods of darkness requiring more lighting, and the 'Aspirational' profile is greater in June as a result of increased demands from fans and refrigeration. The total energy demand per household is 289 Wh/day in June and 173 Wh/day in December with the 'Aspirational' and 'Basic' demands respectively contributing proportionally more to each month.

5.4.2 Energy demand throughout the year

Monthly energy demand

The results of my Monte Carlo simulations are shown as box plots in fig. 5.6 a). As already highlighted, total monthly community energy demand varies throughout the year and is highest in the winter months for the 'Basic' profile and highest in the summer for the 'Aspirational' profile. Additionally, in comparison to the load profiles in fig. 5.5, I display how the variability in demand for energy services results in a range of values for electricity demand which will have an impact on the design of a minigrid system.

Table 5.8 Data used to generate basic and aspirational demand profiles, averaged over the community and presented per household. Ownership and usage data from this work, Ministry of Home Affairs, Government of India (2011) [55], Sen and Bhattacharyya (2014) [59] and Rathi et al. (2012) [224]. Seasonal variation: *highest in winter, **highest in summer. Adapted from Sandwell et al. [195].

Demand	Ownership	Power rating (W)	Usage (hr/day)	Energy demand (Wh/day)
Basic				
LED lights	4.1	3 [35]	7.0-9.0*	86-111
Cell phone (charging)	2.2	5	0.9	2
Cell phone (standby)		1	0.9	2
Aspirational				
Television	0.1 [55]	10 [223]	2 [59]	2
Radio	0.3 [55]	5 [59, 223]	3-4* [59]	9-12
Fan	1.0 [59]	10 [59, 223]	0-9** [59]	0-135
Refrigerator	0.05 [224]	45 [35]	16-20** [59]	36-45

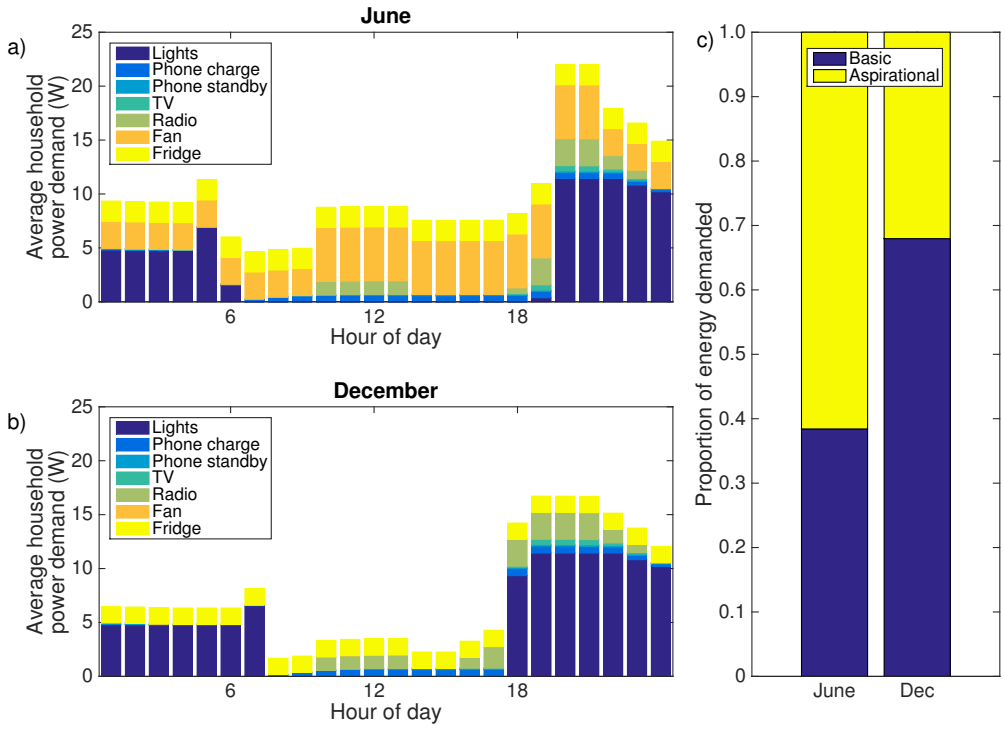


Fig. 5.5 Average daily household power demand by device for a) June and b) December, and c) the proportion of average energy demand from basic services and aspirational demands. From Sandwell et al. [195].

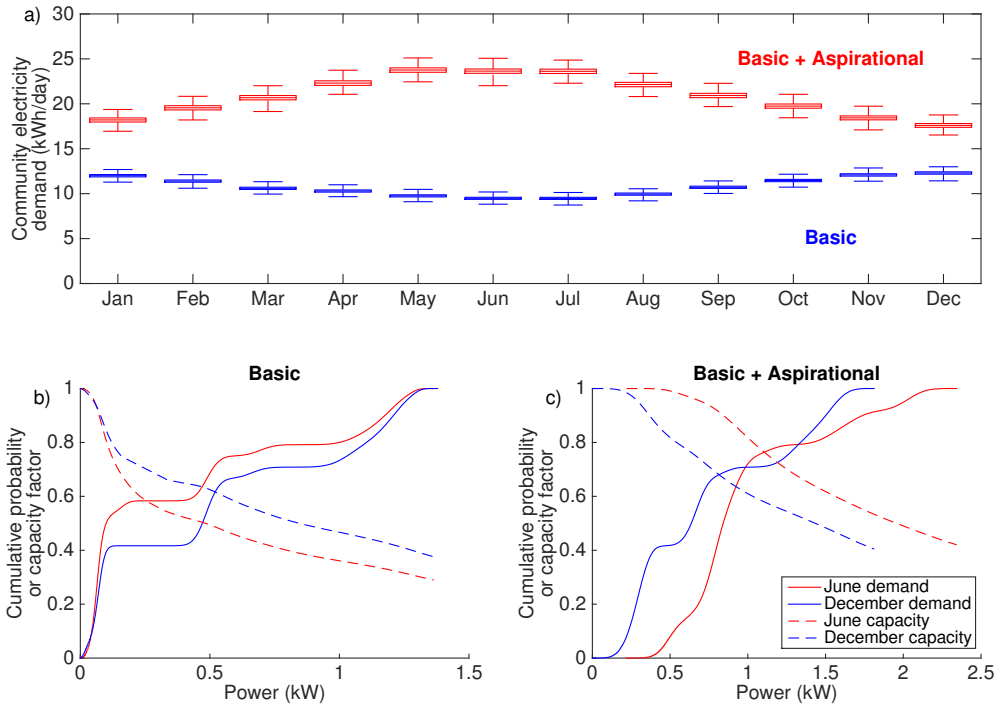


Fig. 5.6 a) Daily community electricity demand; cumulative probabilities of energy demand being satisfied (solid lines) and capacity factor of a power source of a given size (dashed lines) for b) basic demand and c) additional aspirational demand. From Sandwell et al. [195].

This seasonal variation could have a significant effect on the design of off-grid PV and storage systems. For the 'Basic' profile the majority of the energy demand occurs during hours of darkness and, for a system with PV generation, would need to be met via battery storage. A system designed to meet demand in the summer months, at around 9.5 kWh/day, would be undersized by around 20% in meeting demand in the winter months, at around 12 kWh/day. Furthermore a PV array sized for summer months may be unable to suitably charge the battery storage during periods of lower irradiance.

The addition of the 'Aspirational' profile, however, makes meeting the electricity load with PV generation more suitable. Increased demand during the day for fans and refrigerators matches peak generation times of PV, and reduces the risk of battery storage systems being incorrectly sized in comparison to the 'Basic' profile alone. Meeting this increased demand would require a greater investment in infrastructure however the cost per unit of electricity may be reduced as system redundancy is decreased. Furthermore, a price premium could be charged for providing more attractive energy services than lighting and phone charging alone.

System efficacy and capacity factor

The total energy demand is useful in designing and sizing systems to supply a community with electricity consistently throughout the day. I also investigated the CDF of electricity demand, which allows us to interpret the probability that a system of a certain power output will be able to provide the community with electricity services at a given time. If the power output of a generation source is lower than the power demand, a blackout or brownout will occur and could decrease customer satisfaction. The CDFs of power demand are shown by solid lines in fig. 5.6 b) and c) for the 'Basic' and additional 'Aspirational' demand profiles for June and December. I refer to this as the efficacy of a system able to supply a certain

amount of power, an assessment of its ability to meet the demand presented to it by the community.

For the 'Basic' profile, only around 0.1 kW of power is necessary to meet the daytime needs of the community, which is almost exclusively from phone charging. Around 0.5 kW is sufficient to meet overnight lighting needs, and between 0.5–1.0 kW for twilight periods, but to meet the most important evening peak loads then 1.5 kW of power must be continuously available to satisfy the community demand. There is a quantifiable seasonal impact: a 1.0 kW power supply, for example, would be sufficient in meeting demand almost 80% of the time in June but only 70% in December. The effect of seasons on the two CDFs diminishes at larger power demands. Statistically the highest power demands become increasingly rare, which was also observed by Boait et al. [70].

With the addition of the 'Aspirational' profile the CDFs are superficially similar to the 'Basic' profile in December but exhibits two regimes in June. Considering the demand in June, increasing the level of power available from 0.5 kW to 1.0 kW satisfies approximately 80% of demand: this corresponds to meeting demand at all times other than during the evening peak. After this regime, however, incremental gains in demand satisfaction are more marginal: doubling the amount of power able to be supplied to 2.0 kW results in demand being met just 10% more of the time. Providing power during the peak evening time is an important priority to system designers but the benefit of meeting this demand must be weighed against the cost of increasing the system size.

The ability to supply more power to the community allows the system to meet more demand and increase user satisfaction but results in a lower capacity factor, which is defined as the proportion of power supplied as a fraction of the maximum output. The dashed lines in fig. 5.6 b) and c) show the average capacity factor of a system capable of supplying the power shown in on the horizontal axis. Small power systems have high capacity factors, as the demand is almost always higher than their supply, but will be more susceptible to blackouts;

larger power systems will have lower average capacity factors but will meet demand more reliably.

5.4.3 Impact of results on system design

Overview

In this section I will discuss the impacts of varying and seasonal energy demand on the sizing of energy systems. Effective minigrid systems should be designed to reliably meet community electricity demand whilst also maintaining a sufficiently high capacity factor, but sizing a system to achieve both simultaneously can be a significant challenge.

Impact of the capacity factor of power supply

Low capacity factors present an issue for diesel generators, which are recommended to be operated at around 80% of their stated capacity in continuous usage or at 100% capacity only in emergencies [95]. A diesel generator capable of meeting the highest fractions of demand, in both the 'Basic' and 'Aspirational' cases, would be operating a capacity factor as low as 40% during times of reduced demand. Furthermore, for example in the 'Aspirational' case, a 1.4 kW generator meeting 80% of demand has a seasonal difference in capacity factors of 15% (absolute) between June and December, potentially wasting more power in the winter months. This could limit the efficiency of the system: although the demand is being met, the generator is oversized and is likely to be not operating at maximum efficiency [95].

To circumvent this it may be possible to use a system of several smaller generators, each with a fraction of the total desired generation capacity. Each component generator could be operated at an appropriate capacity factor and used when necessary to provide an adequate total supply. This would improve the capacity factor of each generator but could represent an increase in the cost and complexity of the system, both when installed and during operation.

Increasing the capacity factor

Another option to overcome these issues would be to schedule demand and limit it to certain periods of the day. This would have the effect of concentrating the load into shorter periods, increasing it at set times and reducing the variability. For the 'Basic' profile this could be done by not supplying power during the daytime, when generally only cell phones are being charged, in favour of providing electricity in the evening. This would be beneficial for diesel systems, which could be run at a constant and higher capacity factor for shorter and well-defined periods, but would have an adverse effect on systems with PV generation from the mismatch of the times of energy generation and supply to the community.

The capacity factor of PV generation is slightly different to the definition used for diesel generators and other sources, and is calculated by dividing the total energy generated over the lifetime of the system by the energy that would be generated if the system produced a constant power output at its rated capacity for the entirety of its lifetime, both day and night. Although this is different to the implications one can interpret from fig. 5.6 b) and c) for dispatchable generation, one could nonetheless increase the capacity factor of the PV system by minimising the energy that needs to be dumped. As shown in section 3.3, this can have a significant impact on the value of the system.

The additional 'Aspirational' loads would increase the capacity factor of PV system as more demand can be met during the day, reducing the likelihood of dumping energy. The increase in demand during the evening would need to be met by a corresponding increase in battery storage, but as the system sizes and power demand increase the variability decreases, shown by the smoother tails to the CDFs in fig. 5.6 c) compared to fig. 5.6 b).

Limiting the use of fans to the daytime only would help make the demand profile more uniform and increase the predictability of electricity usage; for PV systems this would reduce the need for battery storage and for diesel systems would increase the capacity factor by reducing the required generator size. Alternatively introducing additional loads, such as for

commercial and agroprocessing purposes, would increase the daytime demand. This would increase the capacity factor of PV and would provide a more constant load profile for diesel generators, increasing their capacity factor albeit for a larger generation system.

Hybrid systems for meeting demand effectively and efficiently

Combining several electrification options could provide power both effectively, in terms of providing high reliability, and efficiently, with minimal system oversizing and electricity wastage. A hybrid system could use PV to meet demand during the daytime and charge battery storage, a diesel generator to meet evening peak demands, and energy stored in the batteries to power devices overnight and before sunrise. This would be well-matched to the 'Aspirational' profile: higher daytime demand in the summer will correspond to months of higher irradiance and evening demands, for which a diesel generator would be sized, would remain relatively constant throughout the year. The diesel generator could also be used as a backup system if necessary during periods of low solar resource and, if diesel fuel were unavailable for whatever reason, the community would not be without a power supply.

Combining the benefits of PV, battery storage and dispatchable generation in a hybrid system would provide power more resiliently and, as seen in section 3.3.3, at a lower cost than each technology in isolation. A drawback of this highlighted in section 3.3.3 is that the environmental impact of the power provided will increase compared to PV systems alone. For this reason it may be beneficial to use biomass generation in lieu of diesel to reduce GHG emissions. The Government of Uttar Pradesh, for example, has identified the sustainability of minigrids powered by either or both of PV and biomass generation as an attractive option for rural electrification and has outlined policy support in the form of financial subsidies and infrastructure support [54]. The use of biomass generation is contingent on many other factors, for example adequate access to suitable resources, but nonetheless this highlights the

opportunity to provide sustainable and reliably energy to communities such as those in rural Bahraich District.

5.5 Conclusions

5.5.1 Summary of results

In this chapter I have used the data gathered from rural households in Bahraich District to establish an informative baseline and to estimate the potential energy demand of a community. I found that a typical dwelling has 3.2 $\pm$ 0.3 rooms in which 10.8 $\pm$ 0.9 people live. Households are typically reliant on subsistence farming and own on average 17.3 $\pm$ 3.4 *bighas* of land. Respondents have very low monthly incomes, INR 7900 $\pm$ 1670 per household or INR 860 $\pm$ 125 per person, which means around two thirds of households live in poverty. Respondents spend much of their waking hours working or performing household chores with little free time.

I found that more than 80% of households are primarily reliant on kerosene for lighting. Where available, fixed lights were used on average 30% more than their kerosene counterparts, and torches were used only to move around the village at night and tend to livestock. Owning fixed lights did not have a significant impact on reducing kerosene usage on average: for some households it was greatly reduced, whilst for others there was little or no reduction. Based on the data gathered, I calculate that households spend INR 3243 per year on kerosene lighting and emit 381.1 $kgCO_{2eq}$ of GHGs.

By analysing the times of usage of the devices available to the community I calculated utilisation profiles and, from these, power demand profiles. By aggregating these and incorporating values from the literature I used a Monte Carlo simulation to estimate the electricity demand of an example community of 100 households with either ‘Basic’ or ‘Aspirational’ energy access. The former was found to have a higher energy demand in the

winter, owing to its dependence on lighting, and the latter was found to be higher in the summer, owing to the additional energy demand from fans and refrigerators.

I investigated these seasonal differences and their impacts on system design, finding that generation sources which can supply higher fractions of demand will suffer lower capacity factors which may cause issues for diesel generators. It may be possible to mitigate these issues by regulating the times of energy usage, introducing more daytime demand in the form of agroprocessing for example, or by combining generation sources. Combining PV generation, storage and dispatchable generation in a hybrid system could provide a viable option for supplying reliable and sustainable power to rural communities in Bahraich District.

The demand simulation processes described in this work are further developed in chapter 6 by integrating increasing ownership of electrical devices as the economy of the community develops, and also by including electricity services for commercial and productive usages. Furthermore, in chapter 7, the primary data recorded in these surveys is used to inform the sizing and composition of systems and to evaluate their effectiveness in providing long-term energy access.

5.5.2 Suitability and potential impact of off-grid systems

Systems which supply rural communities with electricity can have a significant impact, both on the wellbeing of the people they provide for and in mitigating GHGs. The process of surveying, analysing and understanding the requirements of rural households helps us in designing appropriate solutions to meet these needs and, by collecting this information, I can integrate it into future energy systems models. This work has provided a baseline for the affordability requirements of electricity services for rural communities and for the amount of GHGs from kerosene that can be mitigated by providing reliable and sustainable power. I will integrate these findings into later chapters.

Ensuring a successful transition from one technology to another will require more than just a well-designed energy system. Mitigating GHG emissions will require eliminating the usage of kerosene lamps: one step towards this will come from providing another option for lighting, removing their necessity, but many more will be required to stop the usage of kerosene entirely. These could include political or social policies which discourage the use of kerosene or encourage the uptake of other lighting options but will likely involve many strategies in concert rather than a single unified solution. With reference to this work, providing a reliable source of electricity will be one necessary component in achieving the aim of mitigating GHGs from kerosene usage and will remain my focus; I will endeavour, however, to appreciate the sociopolitical environment within which the technical solutions I suggest must operate.

Chapter 6

The CLOVER Model

Acknowledgement of contributions

Jenny Nelson and Ned Ekins-Daukes advised on the direction of research and supervised the work. All other work is that of the author.

Previous presentation of this work

Sections of this work have been published as an article in *Energy Procedia* [225]:

Sandwell P, Ekins-Daukes N and Nelson J. What are the greatest opportunities for PV to contribute to rural development? *Energy Procedia*. 2017; **130**:139-146. DOI:j.egypro.2017.09.416. Work from this article is reproduced with permission [112].

Sections of this work were presented as a poster presentation:

Sandwell P, Ekins-Daukes N and Nelson J. What are the greatest opportunities for PV to contribute to rural development? At *SNEC 11th International Photovoltaic Power Generation Conference & Exhibition*, Shanghai, China, 17–20 April 2017.

6.1 Introduction

6.1.1 Overview

From the work presented in previous chapters I have identified a number of improvements that could be made to the process of evaluating the performance and suitability of minigrid systems for rural electrification. In chapter 3 I found that greater consideration should be given to the composition of minigrid systems and how this can best meet demand over time, further work was needed to understand and quantify community electricity usage, and that a single optimisation period of 20 years could be unreflective of how electricity demand is expected to grow. Furthermore in chapter 4 I established that HCPV technology would have a greater GHG mitigation potential when used in utility-scale systems rather than community minigrids rather than for rural electrification, where established PV technologies would be more suitable. Finally, in chapter 5, we gathered primary data from rural communities in Uttar Pradesh, India to directly inform my modelling process to understand both the present levels of energy access and the potential for minigrids to mitigate GHGs from kerosene usage, amongst other benefits. In order to incorporate these findings it was necessary to redesign the computer model previously used in chapter 3 and so I created a new modelling framework. This model, named CLOVER (Continuous Lifetime Optimisation of Variable Electricity Resources), is the subject of this chapter in which I describe its aims, processes, outputs and potential uses.

In this chapter I will describe the CLOVER simulation and optimisation framework which will be used in chapter 7 to assess the impact of using minigrid systems for energy access and GHG mitigation in rural India. The codes which implement the work described in this chapter are available from appendix B. In section 6.1 I will introduce the notation used in this chapter and provide a summary of the relevant literature. In section 6.2 I will describe how sources of energy are treated by CLOVER and in section 6.3 I will present the process

of estimating community load profiles. In section 6.4 I describe how CLOVER treats energy demand and usage as part of an energy system simulation and the assessment outputs that are received when modelling the performance of the minigrid. In section 6.5 I introduce the multi-stage optimisation process which selects the optimum combination of installed energy generation and storage capacities from a range of simulated systems and, further, how CLOVER reoptimises the system over time to account for increasing energy demand. Finally, in section 6.6, I summarise the chapter and the potential usage of CLOVER, for which the assessments given in chapter 7 provide an example.

6.1.2 Notation

The principles of the simulation and optimisation process are centred around time-dependent functions. Some of these, for example renewable energy generation, are predetermined by the user-defined inputs and others, such as the energy stored in the battery, are calculated individually and iteratively at each timestep of the process. Here I will briefly recap some of the notation used in this chapter, whilst a complete description is given in section 2.3.

Throughout this chapter I use a superscript i to denote the general index of a given energy source or device from a set of available technologies provided by the user. For example, if the CLOVER user simulated a hybrid energy system of solar PV and wind power which provides basic household amenities, we would take $i \in \xi_R = \{\text{PV, wind}\}$ for renewables generation and take $i \in \xi_D = \{\text{LED, phone charging, fan}\}$ for energy service devices available. For a dependence on the hour of the day I use an uppercase $H \in \mathbb{Z} : H \in [0,23]$ to denote that hour and for a dependence on the day of the calendar year I use an uppercase $D \in \mathbb{Z} : D \in [1,365]$, where leap-days are not considered, for example a_{HD}. For the day of a simulation I use a lowercase $d \in \mathbb{Z} : d \in [0, \frac{1}{24} t_{\max}]$ which is permitted to run past 365 for the length of the simulation. The utilisation of lighting services, for example, will be governed by H and D

but not by d, whilst the number of households in the community will be dependent on d but not H and D. Further details of the notation used in this chapter is given in section 2.3.1.

A function $a(t)$ tracks the value of a at the timestep t of the computational process, each of which represents one hour in the total simulation lifetime, and is assumed to be constant for that timestep. A timestep of one hour is typical for this type of simulation process [60, 61, 69, 72–75, 86, 87] but a smaller timestep could be used to increase the temporal resolution if desired and at a corresponding increase in computation time. The function $a(t)$ can be assumed to be a step function which can take any finite rational value unless otherwise constrained; for example, if referring to the number of devices in a community then the function would be constrained to non-negative integers. A description of the notation and treatment of functions operates in this paper is given in section 2.3.2.

In some cases there will be notation referring to time points in the simulation process and others reference time points, for example hours in the day, which represent two distinct concepts. I aim to delineate these to by referring to times in the simulation exclusively via the symbol t which runs from $t = 0$, the initial hour in the simulation period, to $t = t_{\max}$ at the end of the simulation and defined by the user.

I assume that the number of households in the community is not seasonally variant and that the utilisation of energy services remains constant throughout the simulation, with more information given in sections 6.3.2 and 6.3.3 respectively. As the simulation operates through the use of functions defined in the form $a(t)$ we are required to convert certain data structures from their original form to one that can be incorporated into the solution. The notation for this conversion is, for example, $a_{HD} \mapsto a(t)$ and the definitions of these are given in section 2.3.3.

Where relevant the variables in this chapter will be introduced using an explicit definition along with an explanation of their indices and dependence on other variables. The notation used in previous chapters, in particular in chapters 2, 3 and 5, is the same as used here and so previously-introduced notation corresponds to the same variables in this chapter.

6.1.3 Summary of literature

Energy systems modelling has been widely used to simulate and optimise electricity systems to meet the demands of rural communities. A review paper by Bahramara et al. [58] summarised the usage of HOMER, the most commonly-used minigrid simulation software, and found that many studies have focused on the use of PV in standalone electricity systems in rural areas of developing countries. They also found that the cost of electricity is used as the determining criterion in the literature for system selection but little consideration was given to other performance metrics, such as the GHG emissions of the system. Kobayakawa and Kandpal [62] explore the use of HOMER for analysing the impact of adding additional generation capacity to match an increase in electricity demand but do so in two discrete optimisation intervals, rather allowing a continuous growth in demand over time.

Boait et al. [69] present a simulation and optimisation model, ESCoBox, for sizing a minigrid system which accounts for fluctuations in electricity demand; this tool also has additional functionality which can be used to control loads in an installed system. This model uses a Monte Carlo simulation to calculate and identify the impacts of variations in demand but, as it has received much less development than commercial models such as HOMER, its capabilities are more limited and it is not suited to long-term scenario analysis.

Only a small number of studies allow small shortfalls in reliability in order to reduce system costs [72, 73, 77]. Louie and Dauenhauer [73], for example, estimate that by allowing their example system in Malawi to provide power 99% of the time, rather than 100%, they are able to reduce the cost of the system by almost half. This gap in the literature has not been adequately explored and also means that no consideration has yet been given to the energy services that are used during periods of system downtime, for example the usage of kerosene lamps when electricity for lighting is unavailable.

Chaurey and Kandpal [76] reviewed the status of PV for decentralised energy access in rural India. They state that many emerging trends are likely to impact energy systems in the

future, including providing electricity for productive uses, using high-efficiency DC devices, hybrid power generation, and exploiting the modularity of renewable energy technologies to expand the capacity of systems over time to meet a growing community electricity demand. The effects of these trends can be assessed using energy systems modelling but at present no tools are available which would adequately capture these considerations and others, such as the need to account for and mitigate GHG emissions.

As described in section 1.4, using HOMER for my analysis would not have been appropriate. Despite its established capabilities this commercial model would not have allowed the flexibility and control that would be possible under my own bespoke framework. HOMER would not allow the growth and variability in demand, nor the growth in system size, that I describe in this chapter. Furthermore evaluating many systems with various blackout percentages would have been much more challenging and the consideration of kerosene mitigation and total GHG emissions would have been impossible. Developing my own framework without the use of proprietary software such as HOMER has allowed me to exercise more control over the most relevant scenarios in my modelling and tailor my analysis to those most important to my research. HOMER is a well-developed and established tool but it is better suited to individual static case study systems rather than the long-term growth and development scenarios I aim to explore. For this reason I developed my own software, CLOVER, which I use in chapter 7 and which serves as a demonstration of the potential of this approach to energy systems modelling.

In this chapter I will describe how CLOVER aims to overcome these challenges and provide a modelling framework that can be used to assess the impact of using minigrids to provide sustainable, affordable and reliable power to rural communities.

6.2 Energy generation

6.2.1 Overview

Simulating and optimising an energy system requires a prediction of the energy being made available to the users: this is particularly important for systems reliant on renewable energy as understanding the daily and seasonal variability of resource will affect its ability to consistently meet the energy demands of the community which, in turn, may vary also vary throughout the year. Furthermore, understanding how various energy generation options can complement one another can assist in designing a system which effectively meets energy demand though a variety of generation technologies. In this section I present how energy sources are used by the CLOVER model: I describe how renewable generation is considered, the inclusion of a grid network of an unreliable grid network, and how battery storage is modelled. I also present the effect of failing to provide sufficient power to the community which results in blackout periods and how these can be mitigated by including diesel generation.

6.2.2 Renewable energy generation

Renewable energy generation is dependent on several factors, including local renewable resources and the specifics of the technology chosen, which emphasises the necessity of accurately modelling its potential energy output. In this work I consider the power supplied by solar photovoltaics through the process described in section 2.4.2, but for generality here I will consider a renewable generation source i taken from the set of available renewable sources ξ_R, each of whose power output at a given time point per functional unit is given by $F^i(t)$. The functional unit will vary for each generation source but reflect the nature of the technology.

For a system with α^i multiples of a functional unit of source i, the total power output from that source is given by

$$R^i(t) = \alpha^i F^i(t) \tag{6.2.1}$$

I assume that, where several generation sources are available as part of a hybrid energy system, no source prioritisation occurs. This means that all of the generated electricity is treated equally rather than, for example, solar generation being used exclusively by the system when wind energy was also available; instead, they are used at a given time in direct proportion to their generation at that time. This means that for any number of renewable sources I take the total generation, $R(t)$, to be the sum of the components,

$$R(t) = \sum_{i \in \xi_R} R^i(t) \tag{6.2.2}$$

and use $R(t)$ as the total capacity of the installed system in the minigrid simulation.

6.2.3 Grid electricity

A connection to the national grid network is an aspiration of many communities. The quality of service, however, is often unreliable in rural areas especially during peak demand hours and hence may be insufficient to meet their needs. To model this I consider at a given hour of the day H there is a probability $\gamma_H \in [0,1]$ that grid service is available for that hour. A value of $\gamma_H = 0$ corresponds to no service ever being available at that time, and if $\gamma_H = 0 \; \forall \; H$ then this is equivalent to no grid electricity being present and is used to simulate an off-grid system. Conversely, $\gamma_H = 1 \; \forall \; H$ corresponds to a totally reliable grid connection with no shortfall in service availability.

By converting $\gamma_H \mapsto \gamma(t)$ and generating a random number $x(t) \in [0,1]$ I generate a profile $G(t)$ such that

$$G(t) = \begin{cases} 1 \text{ for } \gamma(t) > x(t) \\ 0 \text{ for } \gamma(t) \leq x(t) \end{cases} \tag{6.2.3}$$

replicating a grid service which is either on (1) or off (0) at a given time t at each point in the simulation. I assume that there is no seasonal variation in the level of grid service over the year, but daily variation, for example low service reliability during peak evening times, is incorporated.

The model uses grid electricity preferentially, when it is available, to supply power directly to the community. This is motivated by the low tariffs on grid electricity [226] which incentivise using grid power when available and minimise the requirements of the distributed generation. This assumption also acts in parallel with the goals of many governments in ultimately moving to a nationwide reliable grid service, but supported by distributed generation where necessary until such a service can be achieved [54].

Using the grid network to charge battery storage in a minigrid can provide additional generation capacity and reduce the requirements of renewables generation. Technical or policy restrictions may not allow this, however: drawing excess power to use at a later time would introduce an additional strain to the grid network and, if the grid supply is already unreliable, may be prohibited in order to meet the needs of a greater number of communities. Using the grid to charge battery storage is a choice available to CLOVER users but renewables generation is used for charging preferentially to maximise the utilisation of local resources.

6.2.4 Battery storage

Battery storage is a necessity in off-grid renewable energy systems in order to provide reliable power when the generation capacity is insufficient to meet the demand of the community.

The sizing of the storage system must be adequate to provide a sufficient level of service but without inflating the cost of the system such that it becomes unaffordable to the people it aims to serve. As battery storage can contribute a significant proportion of the total system cost, the correct sizing of the battery is imperative to system design.

The process I present here for the charging and discharging of batteries is generic and very similar processes are widely used in the literature [73, 74, 78]. I consider a battery of rated capacity S_r, composed of β functional units of battery storage each with a rated capacity of S_{unit}, such that $S_r = \beta S_{\text{unit}}$. The usable capacity of the battery will be limited between a maximum and minimum proportion of the total capacity, $\kappa_{\max}$ and $\kappa_{\min}$ respectively, where $\kappa_{\max}, \kappa_{\min} \in [0,1] : \kappa_{\max} > \kappa_{\min}$. This difference is commonly referred to as the total depth of discharge *DOD* of the battery,

$$DOD = \kappa_{\max} - \kappa_{\min} \tag{6.2.4}$$

and describes the usable capacity of the battery. The usable capacity of the battery will depend on the allowed depth of discharge and the performance of the battery over time, $\delta^{\text{bat}}(t) \in [0,1]$, will decrease over its lifetime. A description of how $\delta^{\text{bat}}(t)$ is calculated is given in section 2.4.2.

The amount of electrical energy which can be stored in the battery will be constrained by the upper and lower bounds $S_{\max}(t) = \delta^{\text{bat}}(t)\kappa_{\max}S_r$ and $S_{\min}(t) = \delta^{\text{bat}}(t)\kappa_{\min}S_r$ respectively. As such the usable capacity $S_{\text{c}}(t)$ will be given by

$$S_c(t) = \delta^{\text{bat}}(t)(\kappa_{\max} - \kappa_{\min})S_r \tag{6.2.5}$$

and will diminish over time. The total energy stored in the battery at a given time, including that which cannot be accessed owing to *DOD* restrictions, is given by $S(t)$ under the condition

$$S_{\min}(t) \leq S(t) \leq S_{\max}(t) \tag{6.2.6}$$

I take the energy flow into the battery at a given time point to be $E^{\text{bat}}(t)$ where the battery is defined to be charging for $E^{\text{bat}}(t) > 0$. The maximum amount of energy that can flow into or out of the battery, $E^{\text{bat}}_{\text{flow}}(t)$, is defined by the C-rate of the battery, C^{bat}. The C-rate governs the maximum charge and discharge time of a battery and can be used to help prolong its lifetime when this time is increased to reduce the strain on the battery; for example, a system with $C^{\text{bat}} = 2$ would discharge its maximum stored capacity in 30 minutes. I assume that the C-rate of the battery storage is constant throughout the simulation period. The maximum energy flow is given by

$$E^{\text{bat}}_{\text{flow}}(t) = C^{\text{bat}} S_c(t) \tag{6.2.7}$$

which is strictly positive by definition and will diminish over time as the usable battery capacity decreases. The new total energy stored in the battery is given by

$$S(t) = \begin{cases} (1-\sigma^{\text{bat}}_{\text{leak}})S(t-1) + \sigma^{\text{bat}}_{\text{in}} \min\left(E^{\text{bat}}(t), E^{\text{bat}}_{\text{flow}}(t)\right) & \text{for } E^{\text{bat}}(t) \geq 0 \\ (1-\sigma^{\text{bat}}_{\text{leak}})S(t-1) + \frac{1}{\sigma^{\text{bat}}_{\text{out}}} \max\left(E^{\text{bat}}(t), -E^{\text{bat}}_{\text{flow}}(t)\right) & \text{for } E^{\text{bat}}(t) < 0 \end{cases} \tag{6.2.8}$$

where the initial term in each conditional equation refers to the energy leakage out of the battery in one time interval as a proportion $\sigma^{\text{bat}}_{\text{leak}} \in [0,1]$ of the total; $\sigma^{\text{bat}}_{\text{in}}, \sigma^{\text{bat}}_{\text{out}} \in [0,1]$ are the energy conversion efficiencies into and out of the battery storage respectively; and eq. (6.2.8) remains subject to the conditions given by eq. (6.2.6).

6.2.5 Blackout periods

When demand for power exceeds the available supply the energy system suffers a blackout period. Grid networks in developed countries incorporate excess generation capacity to provide sufficient level of redundancy to avoid periods without electricity supply, but this expense can be prohibitive for the relatively small-scale generation of rural minigrids. As a result systems may be designed to include some level of unreliability of service or restrictions on energy usage in order to reduce the cost of the system, and the price for the consumer, to an appropriate level.

If the energy supplied from the system is insufficient to meet the total load demand of the community I define this as a blackout period. Owing to the hourly aggregation of time into timesteps it may be the case that some fraction of a blackout period is spent with power and some without, or a brownout may occur when the voltage of the system drops; as such, my definition of a blackout means that any period of reduced electricity service is considered as inadequate in satisfying the community. This definition ensures that a system will be reliable enough when judging its appropriateness based on the analysis of blackout periods, rather than potentially masking periods of inadequate supply.

I characterise a blackout occurring at time t by the function $B(t)$, defined as

$$B(t) = \begin{cases} 1 & \text{during blackout period} \\ 0 & \text{when demand is satisfied} \end{cases} \tag{6.2.9}$$

and by using the above equation I define the average value of $B(t)$, $\overline{B} \in [0,1]$, as

$$\overline{B} = \frac{1}{t_{\max}} \sum_{t=0}^{t_{\max}} B(t) \tag{6.2.10}$$

which is the proportion of the total simulation period for which blackout periods occur, where $\overline{B} = 0$ corresponds to a completely reliable system with no periods of reduced supply.

Furthermore, one can take a threshold value $B_{\text{thr}} \in [0,1]$ defined by the CLOVER user as the maximum proportion of blackouts allowable by the system: for example, $B_{\text{thr}} = 0.25$ would insist that power is available for at least 18 hours per day. If a system has $\overline{B} \leq B_{\text{thr}}$ then it will meet the reliability needs of the system designer, or if $\overline{B} > B_{\text{thr}}$ then it will not.

6.2.6 Diesel backup generation

If the provision of energy via renewable sources, battery storage and the national grid network is unsuitably reliable then the community may use diesel backup generation to meet its unmet needs. This can be done either through a generation schedule or responsively in reaction to periods of unforeseen energy shortfalls; I consider the case of the latter and to utilise diesel generation as a backup only when other power sources are unavailable, rather than as a main source of energy.

If the proportion of blackouts from the energy system $\overline{B}$ is less than B_{thr}, the allowable threshold specified by the CLOVER user, the diesel generator is used to overcome this shortfall by selecting and supplying power to as many timesteps as necessary to satisfy $\overline{B}_{\text{DBU}} \leq B_{\text{thr}}$, where $\overline{B}_{\text{DBU}}$ is the proportion of time when blackouts occur after the diesel backup generation is considered. This is done through an *a posteriori* analysis of the load demand that was left unmet by blackout periods to select the times when the diesel generator would have been switched on and is described in section 2.4.2, in addition to the processes for sizing the generator and calculating its output.

6.3 Energy usage

6.3.1 Overview

The value of an energy system lies in its ability to provide electricity services and, as such, it is necessary to understand and predict the needs of the community being served. In

domestic settings, households can use energy to meet their basic needs such as for lighting and phone charging, and also for comfort and entertainment, for example using fans and televisions. Energy can also be used to facilitate economic development by providing power to higher-power devices such as tools, handicraft equipment and agricultural machinery. Each energy service, and each device that provides it, will have a unique energy usage profile and by understanding each of these we can aggregate them to establish the community energy demand. Predicting the hourly fluctuations, seasonal variation and year-on-year increases in the demand for electricity will allow us to better design energy systems which meet to the needs of the users and continue to provide reliable power throughout their lifetime.

The total electrical energy demand will be defined on the power requirements of each device and the number of devices in use, with the latter governed by the statistics of usage which itself is dependent on number of households in the community, the average ownership of each device and their utilisation profiles. In this section I will outline the process of generating a load profile for the community as a whole by combining these factors which can later be integrated into the energy system simulation. I will also use a similar process to evaluate the usage of kerosene lamps and its potential mitigation through the provision of electricity for lighting.

6.3.2 Device ownership

I take it that device ownership is proportional to the number of households in the community and as the population increases, so will the number of households. For a community with an initial number of households H_0, the number of households H_d on day d will be given by

$$H_d = \lfloor H_0(1+g_d)^d \rfloor \tag{6.3.1}$$

where $g_d \in [0,1]$ is the daily growth rate of households. This rate can be calculated from the annual population growth rate g_y using the equation

$$g_d = (1+g_y)^{\frac{1}{365}} - 1 \tag{6.3.2}$$

All of the electrical devices considered in the simulation, for both domestic and commercial use, are elements of the set ξ_D. On day d, the number of devices within the community N^i of the type $i \in \xi_D$ can be expressed as an average over the number of households, $n_d^i \geq 0$, such that

$$N_d^i = n_d^i H_d \tag{6.3.3}$$

This proportion n_d^i will depend on the type of device and its attractiveness to the community, and will vary over time. To evaluate this I incorporate the Bass diffusion model [227–229] which incorporates market dynamics into the diffusion of new devices into the community. Households are driven to buy new devices by their own innovation or desire for new products and by imitation of their neighbours who already have access to them. The Bass model states that the cumulative number of devices in the community on a given day can be expressed [227–229] as

$$N_d^i = (n^i{}_{\max} - n_0^i) \left(\frac{1 - e^{-(p^i+q^i)d}}{1 + \frac{q^i}{p^i} e^{(p^i+q^i)d}} + n_0^i \right) H_d \tag{6.3.4}$$

where n_0^i is the average number of devices i per household at the point when the new energy system is available, for example as part of the initial rollout of energy services or compatible devices already acquired for use with an existing weak grid connection; $n_{\max}^i$ is the ultimate market saturation of the device, for example owing to its appeal or affordability to only a subset of households; and p^i and q^i being constants describing the innovative and imitative appeal of a device as defined by the Bass model. These parameters can be difficult or

impossible to assess *a priori* and are often calculable only after analysing large quantities of market data [228, 229]: for the purpose of using this model, representative values are used to simulate market trends and the comparative appeal of various devices. The use of eq. (6.3.4) allows the expression of eq. (6.3.3) for N_d^i in terms of estimable quantities and I may then convert $N_d^i \mapsto N^i(t)$ for the energy system simulation.

6.3.3 Device utilisation

Overview

Communities using an energy system rely on it to provide them with the services they desire. Their demand for these services is dependent both on the time of day and the time of year, related to the times of sunset for domestic lighting or agricultural cycles for crop processing machinery, for example. As in chapter 5 I consider the likelihood that a given device will be used as its utilisation factor, $u_{HD}^i \in [0,1]$, for the hour of the day $H \in \mathbb{Z} : H \in [0,23]$ and the day $D \in \mathbb{Z} : D \in [1,365]$ in the calendar year. The value u_{HD}^i can be considered as the probability that, given a device exists in the system, its services will be used by the household it is in at that given time. The total number of hours of device usage per day can be given by

$$U_D^i = \sum_{H=0}^{23} u_{HD}^i \tag{6.3.5}$$

and can be used in establishing payment plans. For example, a minigrid operator could offer a tariff which allows up to six hours of LED lighting services per day, for which the utilisation u_{HD}^{LED} will be constrained such that $U_D^{\mathrm{LED}} \leq 6 \; \forall \; D$. I convert $u_{HD}^i \mapsto u^i(t)$ for use in an energy system simulation.

Demand for energy services

For most devices I assume that u^i_{HD} is constant throughout the simulation period, meaning that the desire of households to use a given energy service does not change between two equivalent points in the year and is not dependent on the number of such devices that a household has access to. This assumption is fairest for devices such as lighting and phone charging but may be less accurate for entertainment services such as televisions, for example [101]. In the context of minigrids for rural development, however, the average ownership n^i_d for devices such as these is often less than one, meaning that the likelihood that a single household has access to two or more is low and this assumption remains valid.

Utilisation of weather-dependent devices

Some devices, such as fans, will have their utilisation $u^i(t)$ dependent on the local weather conditions and not necessarily the time of day and the day of the year. To model the effect of temperature and humidity upon the likelihood that a device will be switched on at a given time I used the *humidex* number, short for humidity index. This is an empirically derived and defined number which quantifies the level of discomfort a person experiences and is similar to the wind-chill factor. The dimensionless humidex $H(t)$ is given by [230]

$$H(t) = T_{\text{air}}(t) + 0.5555\left(6.11e^{5417.7530\left(\frac{1}{273.16}-\frac{1}{T_{\text{dew}}(t)}\right)} - 10\right) \tag{6.3.6}$$

where T_{air} is the ambient air temperature in °C and T_{dew} is the dew point in K, both of which are a function of time t. A humidex in the region 20-29, for example, will cause little discomfort to the average person whilst a humidex of more than 45 can threaten heatstroke.

To find $u^i(t)$ I assume that it will be normally distributed around a mean humidex value that I take to be $H_{\text{mean}} = 40$, the threshold defined to be between "some discomfort" and "great discomfort" for example equivalent to 30°C at 65% humidity, and for which I define

$u^i = 0.5$. I can then map $H(t) \mapsto u^i(t)$ using the formula

$$u^i(t) = \frac{1}{2}\left[1 + \text{erf}\left(\frac{H(t) - H_{\text{mean}}}{10}\right)\right] \tag{6.3.7}$$

where $\text{erf}(y)$ is the error function of the variable y and the right-hand side of eq. (6.3.7) describes the cumulative probability function of the normal distribution. This gives $u^i(t) \in [0,1]$ $\forall\, H(t)$ and hence a utilisation profile for a weather-dependent device.

6.3.4 Electricity demand

In order to calculate the total number of devices in use at a given time point in the simulation, $D^i(t)$, I consider the number available in the community at that time, $N^i(t)$, and their utilisation, $u^i(t)$. I evaluate $D^i(t)$ as the number of successful trials from a binomial distribution, with $u^i(t)$ as the probability of success and $N^i(t)$ as the total number of trials, with the probability density function $P(D^i)$ given by

$$P\left(D^i, t\right) = \binom{N^i}{D^i} \left(u^i\right)^{D^i} \left(1 - u^i\right)^{\left(N^i - D^i\right)} \tag{6.3.8}$$

where each variable is a function of t but this have been omitted for clarity. The number of devices in use is found by calculating the value of $D^i(t)$ in the cumulative probability function which corresponds to a randomly generated number $x^i(t) \in [0,1]$ for each device i and for every value of t. This is expressed by solving the equation

$$\sum_{k=0}^{\lfloor D^i \rfloor} \binom{N^i}{k} \left(u^i\right)^k \left(1 - u^i\right)^{\left(N^i - k\right)} = x^i(t) \tag{6.3.9}$$

for every time point in the simulation. This approach was described previously by Boait et al. [70] and was used in chapter 5 and introduces a level of variation in demand which is

more realistic to the situation at hand when compared to those which consider static device usage [73]. An overview of the process for synthesising load profiles is given in fig. 6.1.

Once the total number of each type of device is known then the total power demand can be calculated. I take each device to draw a given power W^i when in use and the total load for each device type, $L^i(t)$, is given by

$$L^i(t) = W^i D^i(t) \tag{6.3.10}$$

at each time step of the simulation. I assume that each device type has only one power rating: this makes a distinction between, for example different kinds of lighting solutions like LEDs and CFLs which may both be present in the same energy system but require different amounts of electricity to receive the same level of service. If these two lighting services were present in the same system they could be considered as two separate device categories with the same utilisation profile, $u^{\mathrm{LED}}(t) = u^{\mathrm{CFL}}(t)$, but different power requirements, $L^{\mathrm{LED}} \neq L^{\mathrm{CFL}}$.

By aggregating the loads of all devices I can generate the total community electricity demand yielded by

$$L(t) = \sum_{i \in \xi_D} W^i D^i(t) \tag{6.3.11}$$

which is used as an input into the energy system simulation. This yields a load profile which varies dependent on the time of day, the day of the year, the diffusion of electricity services in the community and weather patterns, as appropriate.

6.3.5 Kerosene lighting demand

If lighting services are unavailable from the minigrid system owing to a blackout period then the users of that system may rely on forms of lighting used previously, such as kerosene lamps, to meet their needs. A demand profile for the usage of kerosene lamps can be synthesised from an appropriate utilisation profile $u^{\mathrm{K}}(t)$ which is likely to be similar to, for

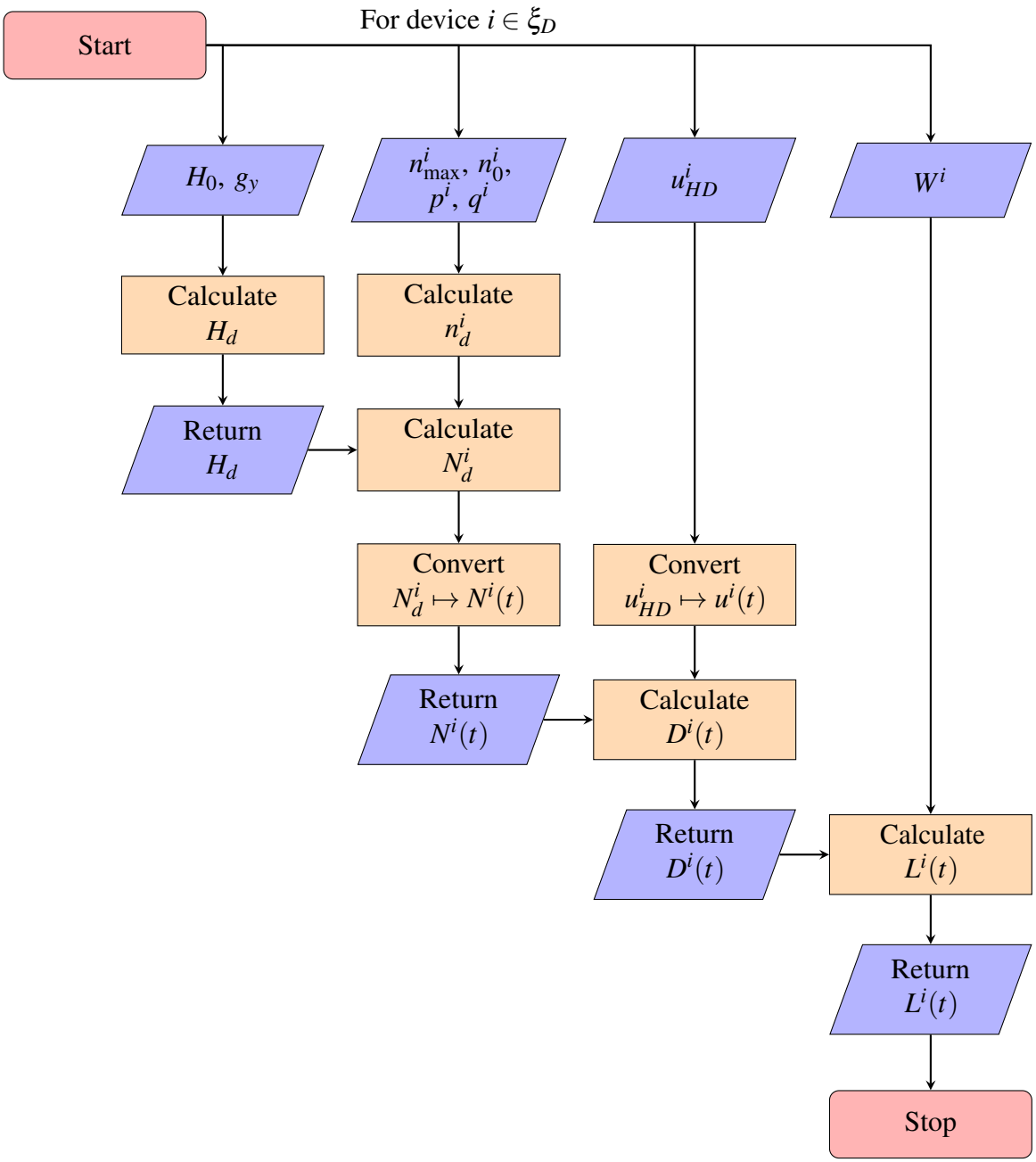


Fig. 6.1 Flowchart overview of the process used to synthesise a load profile for device $i \in \xi_D$.

example, the utilisation profile for electrical lighting from LEDs, $u^{\mathrm{LED}}(t)$, but could have a lower total average daily usage such that $U_{\mathrm{D}}^{\mathrm{K}} < U_{\mathrm{D}}^{\mathrm{LED}}$. This would reflect the fact that, given each lighting source in isolation, communities would use electrical lighting for more hours per day than they would with kerosene lamps.

To model the use of kerosene as a backup lighting source I consider the blackout profile $B(t)$. For a total number of kerosene lamps in the community $N^{\mathrm{K}}(t)$ the total being used at a time t, $K(t)$, is given by

$$K(t) = D^{\mathrm{K}}(t) \circ B(t) \tag{6.3.12}$$

where $D^{\mathrm{K}}(t)$, the amount of kerosene lamp usage in the absence of any electricity provision, is defined by eq. (6.3.9) and the blackout probability $B(t)$ is defined by eq. (6.2.9). This also allows a measurement of the mitigation of kerosene usage by an energy system. The kerosene mitigation profile $M^{\mathrm{K}}(t)$, defined as

$$M^{\mathrm{K}}(t) = D^{\mathrm{K}}(t) - K(t) \tag{6.3.13}$$

tracks the amount of kerosene lamps that would have been in use if not for the presence of the system. By assigning a levelised cost per hour $C_{\mathrm{hr}}^{\mathrm{K}}(t)$ and GHG emissions per hour $\varepsilon_{\mathrm{hr}}^{\mathrm{K}}$ to kerosene lamp usage I can quantify the total cost savings $M_{\mathrm{C}}^{\mathrm{K}}$ and GHG emissions reduction $M_{\mathrm{GHG}}^{\mathrm{K}}$ of the system through kerosene mitigation. These values should be a representative average of all of the kerosene lamps in use as the costs and emissions of each device may vary. Using the equations

$$M_{\mathrm{C}}^{\mathrm{K}} = \sum_{t} C_{\mathrm{hr}}^{\mathrm{K}}(t) \circ M^{\mathrm{K}}(t) \tag{6.3.14}$$

and

$$M_{\mathrm{GHG}}^{\mathrm{K}} = \varepsilon_{\mathrm{hr}}^{\mathrm{K}} \sum_{t} M^{\mathrm{K}}(t) \tag{6.3.15}$$

I can analyse the benefit of the energy system compared to a counterfactual case where no system is present. A similar process to the one used in eq. (6.3.14) and **??** can be used to calculate $D_{\mathrm{C}}^{\mathrm{K}}$ and $D_{\mathrm{GHG}}^{\mathrm{K}}$, for kerosene usage when no system is present for a baseline comparison, and K_{C} and K_{GHG}, for the continued usage of kerosene lamps despite the presence of the energy system.

This metric can also be used to assess the benefits of two different system configurations which obtain the same blackout percentage $\overline{B}$: in one the blackouts may occur in the evening when kerosene demand is highest, but another may have blackouts in the daytime and mitigate kerosene lamp usage more effectively. In this case, the system designer may choose to opt for the latter system as the benefits of kerosene mitigation can deliver greater savings to the community and offset incumbent GHG emissions.

6.4 Minigrid simulation

6.4.1 Overview

The performance of the energy system is simulated for a given combination of renewable energy sources and storage technologies, types of available energy services and in the presence or absence of a grid connection or diesel backup generation. The simulation does not consider their economic or climate change impact, for example, of the choices made by the user as these are included in the optimisation process described in section 6.5. The simulation models only the technological performance of the components selected their ability to meet the demands of the community. The simulation process described in section 6.4.2 is similar to others in the literature and builds on the brief description given in section 2.4.4 but the outputs that are recorded, shown in section 6.4.3, are typically much more detailed than those described in other works, particularly with regards to their resolution.

6.4.2 Simulation process

The simulation runs between two time points, $t_{\text{start}} \leq t \leq t_{\text{stop}}$, set by the user. The user selects the set of renewable generation options to be considered ξ_R, their respective installed capacities α^i, the presence and reliability of the grid network, the number of installed battery storage units β, and the presence and threshold of a diesel backup generator B_{thr}. Data informing the total load demand, for example the set of available devices ξ_D and their power requirements W^i, are defined separately along with the demographic and device ownership statistics; if desired these can be altered independently to the energy system parameters. In this simulation the goal is to assess the performance of some combination of energy technologies in meeting the needs of the community.

Each system that is considered will have a unique performance dependent on the combination of input parameters chosen by the user. I use Ψ to represent a system of a given set of parameters, such that

$$\Psi = \Psi\left(\alpha^i, \beta, t_{\text{start}}, t_{\text{stop}}, L(t), G(t), B_{\text{thr}}\right) \tag{6.4.1}$$

where typically α^i and β will be changed by the user on a case-by-case basis and where t_{start}, t_{stop}, $L(t)$, $G(t)$ and B_{thr} will be kept the same. This allows a comparison of the performance of different energy systems under the same conditions.

The simulation begins by assessing the total renewables output $R(t)$ from eq. (6.2.2), the grid availability $G(t)$ from eq. (6.2.3) and the total community power demand $L(t)$ from eq. (6.3.11). The energy required to satisfy the load demanded is given by $E_L(t)$, where

$$E_L(t) = \frac{1}{\sigma_{\text{tr}}^L} L(t) \tag{6.4.2}$$

and similarly the energy supplied to the system $E_R(t)$ can be given by

$$E_R(t) = \sigma_{\text{tr}}^R R(t) \tag{6.4.3}$$

where $\sigma_{\text{tr}}^L, \sigma_{\text{tr}}^R \in [0,1]$ are the proportions of transmitted energy between the system and the load devices and from the renewable sources respectively to account for electrical losses. When the grid is available it will supply power to the loads and will therefore provide an energy $E_G(t)$ where

$$E_G(t) \equiv G(t) \circ E_L(t) = \sigma_{\text{tr}}^G V^{\text{G}}(t) \tag{6.4.4}$$

and σ_{tr}^G is the conversion efficiency from the grid power supplied $V^{\text{G}}(t)$ to energy in the system. Grid power is supplied to the system preferentially if available ahead of generation from renewable sources to represent an operational strategy which takes advantage of low grid power prices whenever the supply is available, and in doing so will reduce the sizing requirements of the renewable generation. $E_G(t) = 0 \; \forall \, t$ when there is no grid connection available.

The energy required from the off-grid components, $E_{OG}(t)$, is given by

$$E_{OG}(t) = E_L(t) - E_G(t) \tag{6.4.5}$$

of which some will be supplied directly from renewables generation and some from the battery storage. The energy required from the battery storage, $E_{\text{Bat}}(t)$, will be given by

$$E_{\text{Bat}}(t) = E_R(t) - E_{OG}(t) \tag{6.4.6}$$

and is characterised such that for $E_{\text{Bat}}(t) \geq 0$ the load demand is completely satisfied by the renewables generation and any excess is used to charge the battery, and for $E_{\text{bat}}(t) < 0$ the renewables generation is insufficient and energy is required to be drawn from the battery.

Once $E_{\text{Bat}}(t)$ is calculated the simulation begins and evaluates in turn the value of $S(t)\ \forall\ t : t_{\text{start}} \leq t \leq t_{\text{stop}}$, where $S(t)$ is given by eq. (6.2.8) and subject to the constraints given by eq. (6.2.6). If grid charging is enabled by the user, $E_{\text{Bat}}(t) < E_{\text{Bat}}^{\text{flow}}$ and $G(t) = 1$, the battery storage is charged further after the energy from renewables is used, again under the same constraints.

A blackout occurs at time τ when the load demanded is greater than the energy that which can be provided by renewable generation and supplying the remaining energy requirement would violate either $S(\tau) \geq S_{\text{min}}(\tau)$ or $|E_{\text{Bat}}(\tau)| \geq E_{\text{Bat}}^{\text{flow}}$. This is recorded in the profile $B(t)$. If a diesel backup generator is present and $\overline{B} > B_{\text{thr}}$ then the process described in section 6.2.6 is used to calculate its usage and $B_{\text{DBU}}(t)$. An overview of the simulation process is shown in fig. 6.2.

6.4.3 Simulation outputs

The outputs of the simulation of the energy system Ψ are recorded as functions of t in the range $t_{\text{start}} \leq t \leq t_{\text{stop}}$ and stored for later analysis by the user. These are generated in the three stages of the simulation: initialisation, where the input parameters are established; iteration, where the simulation is run for each value of t; and finalisation, where the simulation is concluded with post hoc analysis.

Outputs generated in the initialisation stage are predetermined based on the availability and generation profiles of the various energy sources and the load demands of the community set by the user. During the iterative stage, further outputs are generated as the simulation assesses the performance of the system with respect to the load demanded and the cycling of the battery storage. The finalisation stage assesses the use of the diesel backup generator, if applicable, and reanalyses the blackout profile after its inclusion. A summary of the outputs is given in table 6.1.

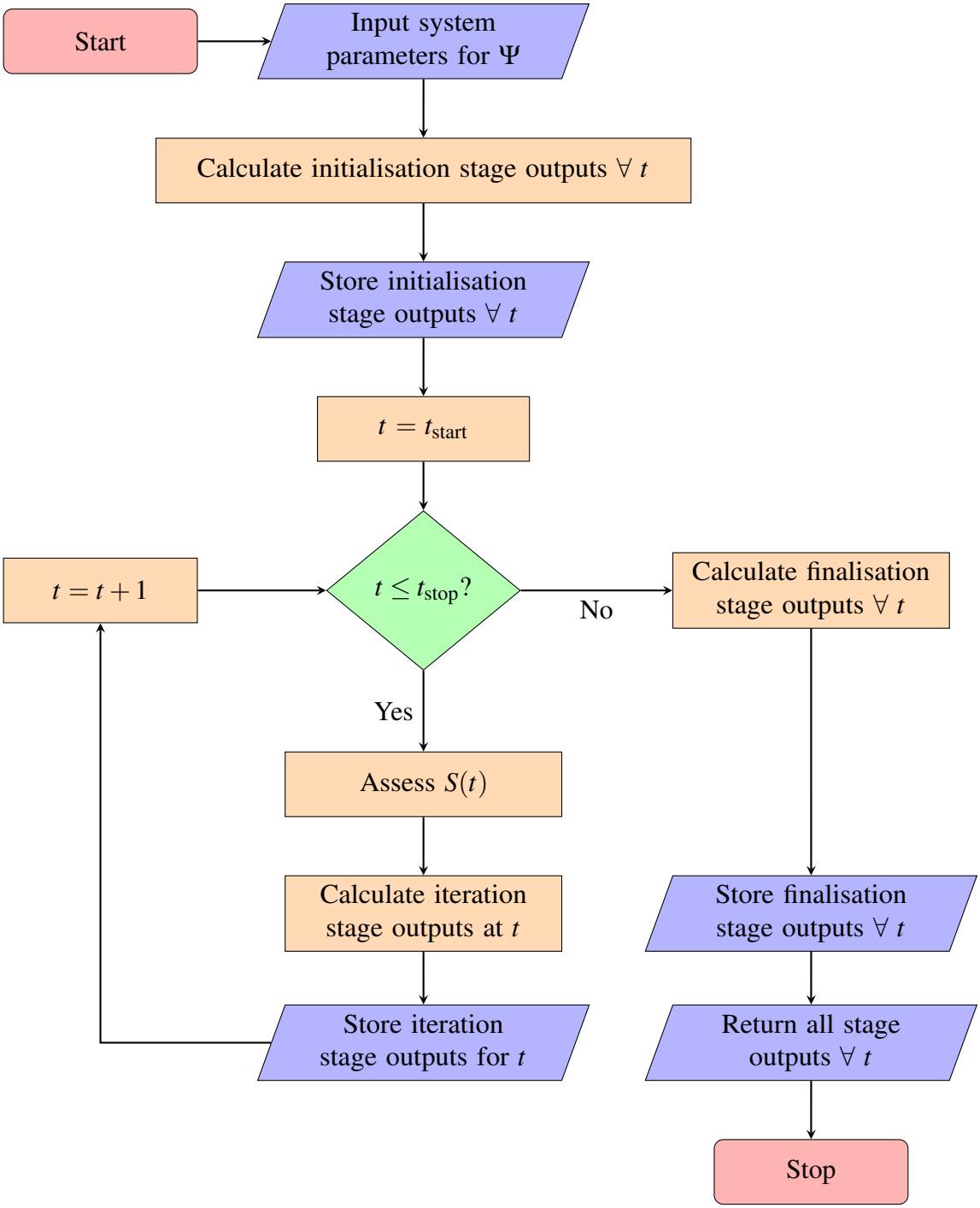


Fig. 6.2 Flowchart overview of the simulation process.

Table 6.1 Energy system outputs generated at the initialisation, iteration and finalisation stages of the simulation process. Blackout times are recalculated in the finalisation stage only if diesel generation is used.

Simulation output	Description
Initialisation stage	
Renewables power	Generation of each renewables source, $R^i(t)$
Load power	Power required to meet load demand, $E_L(t)$
Grid power	Power supplied by the grid, $E_G(t)$
Direct power	Total renewables power supplied directly to loads
Direct power by source	Renewables power supplied directly to loads by each source
Iteration stage	
Battery storage level	Total energy in the battery storage, $S(t)$
Storage power supplied	Total power supplied by battery storage to loads
Storage from renewables	Storage power supplied, segregated by renewables source
Storage from grid	Storage power supplied originating from the grid
Battery health	Degradation factor of the battery storage, $\delta^{\text{bat}}(t)$
Energy surplus	Excess energy from renewables that cannot be used or stored
Energy deficit	Energy that is demanded during blackouts but not satisfied
Blackout times	Times when blackouts occur, $B(t)$
Finalisation stage	
Diesel times	Times when diesel generator is on (1) or off (0)
Diesel Power	Power supplied by diesel backup generator, $E_{\text{DBU}}(t)$
Blackout times	Times when blackouts occur, $B(t)$

The simulation outputs correspond the values of each parameter at each time t in the simulation. This allows the user to, for example, evaluate the energy generated by different renewable sources, monitor the state of charge of the battery, and characterise blackout periods to an hourly resolution. This can allow for a detailed analysis of the performance and usefulness of the energy system which would be impossible if using assessment criteria averaged over the simulation period.

6.5 Lifetime optimisation

6.5.1 Overview

Different combinations of technological solutions can produce similar results in terms of satisfaction of the demand of the community. Furthermore, energy systems with similar costs or GHG emissions could have significant differences in performance. For this reason I simulate and assess many different combinations of technologies, firstly to judge their suitability for the community and secondly to select an optimum system to be installed.

The user defines two criteria that are used in the optimisation process. The first is the sufficiency criterion, which I take to be the blackout threshold B_{thr}: any system that has $\overline{B} \leq B_{\text{thr}}$ is deemed to be adequate at meeting the needs of the community and can be considered as a viable electrification option. The second is the optimisation criterion, which I take to be the system with the lowest LCUE. This process therefore selects a single system which is both viable and provides electricity at the lowest cost. Other parameters could also be used to select an optimum system, however in this work I focus on these parameters only for clarity and comparability to other studies. This approach ensures that the supply of electricity provided to the community is both reliable and affordable before its sustainability and potential to mitigate GHGs is assessed.

The optimisation process spans the lifetime of the system and is divided into shorter time intervals. At the beginning of each shorter time interval the processes for system sizing and simulation are run and the optimum system for that time interval is selected. This optimum system is chosen to be installed at the start of that short time interval. For the next time interval the process repeats, and continues until the end of the lifetime of the system. For example, for a system lifetime of 20 years and a time interval of four years, the optimisation process initially considers the first four years only in the first interval. Systems are simulated over the period from the first day of the first year to the last day of the fourth year, their

performances are analysed, the optimum system for those first four years is identified, and it is chosen to be installed at the start of the first year. In the second interval, systems are simulated from the first day of the fifth year to the last day of the eighth year only, their performances are analysed, the optimum system for the second period of four years is identified, and it is chosen to be installed at the first day of the fifth year. The process then continues similarly until the end of the system lifetime is reached. This section provides a mathematical description of this process and the algorithms governing it.

6.5.2 Optimisation process

Evaluating the considered systems

The optimisation process runs from $t = 0$ to $t = t_{\text{max}}$ and is composed of N_{int} equal and successive time intervals. Each of these intervals begins and ends at t^s_{start} and t^s_{stop} respectively for interval number $s \in \mathbb{Z} : s \in [1, N_{\text{int}}]$ and where $t^1_{\text{start}} = 0$, $t^{N_{\text{int}}}_{\text{stop}} = t_{\text{max}}$ and $t^{s+1}_{\text{start}} = t^s_{\text{stop}} + 1$. The user preinitialises the optimisation process by defining t_{max}, s, the community demand profile and the reliability or absence of a grid connection and diesel backup generation. The blackout threshold B_{thr} is also selected as the value for the sufficiency criterion. During each of these intervals a variety of energy system simulations are performed, with a different combination of sizes of renewable energy technologies, to assess their suitability. Every combination of renewable generation capacities and battery capacities are considered as independent systems $\Psi^s_j \in \xi^s_{\text{sys}}$, the set of considered systems for interval s.

Before the first interval the user selects each technology to be included in the simulation, $i \in \xi_R$, and defines a initial minimum $\alpha^{i,1}_{\text{min}}$ and maximum $\alpha^{i,1}_{\text{max}}$ capacity that the technology can have for the simulation period $s = 1$. The user also defines a step size, α^i_{step}, which determines resolution at which the different possible capacities are investigated and is subject

to the condition

$$\frac{\alpha^{i,1}_{\max} - \alpha^{i,1}_{\min}}{\alpha^{i}_{\text{step}}} \in \mathbb{Z}^{+} \tag{6.5.1}$$

This produces a set of initially available capacity sizes for the technology given by

$$\xi^{1}_{\alpha^i} = \{\alpha^{i,1}_{\min}, \alpha^{i,1}_{\min} + \alpha^{i}_{\text{step}}, \ldots, \alpha^{i,1}_{\max} - \alpha^{i}_{\text{step}}, \alpha^{i,1}_{\max}\} \tag{6.5.2}$$

which are used in the first simulation period. An equivalent process is used to determine the set of available battery capacities ξ^{1}_{Bat} from which the initial rated capacity $S^{1}_{r} = \beta^{1} S_{\text{unit}}$ will be chosen. For an arbitrary simulation period s, eq. (6.5.2) is generalised to

$$\xi^{s}_{\alpha^i} = \{\alpha^{i,s}_{\min}, \alpha^{i,s}_{\min} + \alpha^{i}_{\text{step}}, \ldots, \alpha^{i,s}_{\max} - \alpha^{i}_{\text{step}}, \alpha^{i,s}_{\max}\} \tag{6.5.3}$$

and the corresponding equation for ξ^{s}_{Bat} is given by

$$\xi^{s}_{\text{Bat}} = \{\beta^{s}_{\min}, \beta^{s}_{\min} + \beta_{\text{step}}, \ldots, \beta^{s}_{\max} - \beta_{\text{step}}, \beta^{s}_{\max}\} \tag{6.5.4}$$

from which the number of functional units of battery storage is selected.

The total number of simulations, N^{s}_{sys}, given by

$$N^{s}_{\text{sys}} \equiv |\xi^{s}_{\text{sys}}| = |\xi^{s}_{\text{Bat}}| \prod_{i} |\xi^{s}_{\alpha^i}| \tag{6.5.5}$$

for the simulation period s. Each simulation requires the same computational time but the total time taken for each interval of the optimisation process can be altered by changing N^{s}_{sys}, for example by reducing $|\xi^{s}_{\alpha^i}|$.

Selecting the optimum system

Of the N^s_{sys} systems considered for s, some of Ψ^s_j will meet the sufficiency criteria I considered earlier, $\overline{B} \leq B_{\text{thr}}$, and would therefore be viable options for meeting the electrification needs of the community. I consider these $\Psi^s_k \in \xi^s_{\text{suff}} \subset \xi^s_{\text{sys}}$ where Ψ^s_k is a system meeting the sufficiency criteria and ξ^s_{suff} is the set of all system for which this is true.

One of these systems will have the lowest LCUE, given by the function $\mathscr{L}(\Psi)$. I define the optimum system to be Ψ^s_{opt} and is given by the condition

$$\mathscr{L}\left(\Psi^s_{\text{opt}}\right) = \min\left(\mathscr{L}\left(\Psi^s_k\right)\right) \forall\ \Psi^s_k \in \xi^s_{\text{suff}} \tag{6.5.6}$$

where Ψ^s_{opt} has the installed generation capacities $\alpha^{i,s}_{\text{opt}}$ and total battery capacity $S^s_{\text{opt}} = \beta^s_{\text{opt}} S_{\text{unit}}$. I therefore choose the system Ψ^s to be installed after simulation interval s, where

$$\Psi^s\left(\alpha^{i,s}, \beta^s\right) = \Psi^s_{\text{opt}}\left(\alpha^{i,s}_{\text{opt}}, \beta^s_{\text{opt}}\right) \tag{6.5.7}$$

and is optimised up to and including the current situation interval.

Increasing system capacity

The first interval of the optimisation process evaluates simulations in the range $0 \leq t \leq t^1_{\text{stop}}$ and yields the optimum system $\Psi^1\left(\alpha^{i,1}, S^1_r\right)$. The next system, Ψ^2 for the range $t^2_{\text{start}} \leq t \leq t^2_{\text{stop}}$, will depend on the combination of generation sources installed for Ψ^1: installations made in the first generation period will still be producing electricity in the second period, allowing for energy to be generated at no further installation cost. Furthermore, as the demand of the community grows in response to increased energy access, the generation of the system must also increase to meet the same levels of community satisfaction; this assumption may not be the case for systems where device ownership is, for whatever reason, static or decreasing, however the optimisation process is designed for instances of increasing

energy access and therefore the user should take sufficient care when modelling systems where this is not the situation. The effect of this is that it is counterproductive to assess a smaller installed capacity for the second period than the first, for example $\alpha^{i,2} < \alpha^{i,1}$, as this increases N_{sys}^{s} and with it the total simulation time. It also may be the case that, as demand has grown, $\alpha_{\text{opt}}^{i,2} > \alpha_{\text{max}}^{i,1}$; this means that the optimum generation capacity of Ψ^2 would not be simulated and therefore not able to be selected. This therefore requires us to simulate larger-capacity systems to satisfy an increased demand for electricity.

To do this the user selects two values which are used to define the sets $\xi_{\alpha^i}^{s+1}$ and ξ_{Bat}^{s+1} based on the values of $\alpha^{i,s}$ and β^s. The two values, $\lambda_{\text{min}}^{i} \in \mathbb{N}$ and $\lambda_{\text{max}}^{i} \in \mathbb{N} : \lambda_{\text{max}}^{i} \geq \lambda_{\text{min}}^{i}$, are set and used such that

$$\alpha_{\text{min}}^{i,s+1} = \alpha^{i,s} + \lambda_{\text{min}}^{i} \alpha_{\text{step}}^{i} \tag{6.5.8}$$

and

$$\alpha_{\text{max}}^{i,s+1} = \alpha^{i,s} + \lambda_{\text{max}}^{i} \alpha_{\text{step}}^{i} \tag{6.5.9}$$

for the new set of considered capacities, $\xi_{\alpha^i}^{s+1}$, using eq. (6.5.3). Comparable inputs and an equivalent process are used to generate ξ_{Bat}^{s+1} from β^s. This gives the set of considered generation capacities and battery storage sizes to be, explicitly in terms of the values from the previous interval,

$$\begin{aligned} \xi_{\alpha^i}^{s+1} = \{&\alpha^{i,s} + \lambda_{\text{min}}^{i} \alpha_{\text{step}}^{i}, \alpha^{i,s} + \left(\lambda_{\text{min}}^{i} + 1\right) \alpha_{\text{step}}^{i}, \ldots, \\ &\alpha^{i,s} + \left(\lambda_{\text{max}}^{i} - 1\right) \alpha_{\text{step}}^{i}, \alpha^{i,s} + \lambda_{\text{max}}^{i} \alpha_{\text{step}}^{i}\} \end{aligned} \tag{6.5.10}$$

and

$$\begin{aligned} \xi_{\text{Bat}}^{s+1} = \{&\beta^s + \lambda_{\text{min}}^{\text{Bat}} \beta_{\text{step}}, \beta^s + \left(\lambda_{\text{min}}^{\text{Bat}} + 1\right) \beta_{\text{step}}, \ldots, \\ &\beta^s + \left(\lambda_{\text{max}}^{\text{Bat}} - 1\right) \beta_{\text{step}}, \beta^s + \lambda_{\text{max}}^{\text{Bat}} \beta_{\text{step}}\} \end{aligned} \tag{6.5.11}$$

The user can set the current generation capacity to be the smallest one considered by the next interval by setting $\lambda^{i}_{\text{min}} = 0$, or if the demand increases significantly they can use a larger λ^{i}_{min} to discount smaller systems and reduce computational time. Similarly λ^{i}_{max} can be limited if the real-world constraints of the system limit the amount of energy generation that could be installed at once, for example the amount of land that can be obtained at a site in the considered timeframe. This therefore gives a new range of potential generation capacities which can be modelled in the next simulation process, allowing the capacity to be increased in response to increasing demand.

Optimising over the system lifetime

Once an optimum system Ψ^{s} has been found for the simulation interval s and the new selection of considered systems $\Psi^{s+1}_{j} \in \xi^{s+1}_{\text{sys}}$ have been simulated, the new viable systems $\Psi^{s+1}_{k} \in \xi^{s+1}_{\text{suff}}$ must be identified. This is done by considering the impact of transitioning from the installed system Ψ^{s} to every considered system Ψ^{s+1}_{j} as well as the previous impact of Ψ^{s}. The impact of the system, in terms of blackouts, energy generation, costs and other factors, is calculated to up to and including the end of the interval $s+1$ to assess the cumulative impact of the system up to $t = t^{s+1}_{\text{stop}}$. It is this cumulative assessment that is used to find the sufficient systems Ψ^{s+1}_{k} and the optimum system Ψ^{s+1}_{opt}, which is then installed as Ψ^{s+1} and used as the starting point for the next simulation interval.

The optimisation process continues until the final interval for which $s = N_{\text{int}}$ and $t^{s}_{\text{stop}} = t_{\text{max}}$. At this point, assuming the sufficiency condition has been met during each simulation interval, the optimised installed systems $\Psi^{s}\ \forall\ s$ are returned to the user in addition to information about their impacts after each period in the system lifetime. An overview of the optimisation process is shown in fig. 6.3.

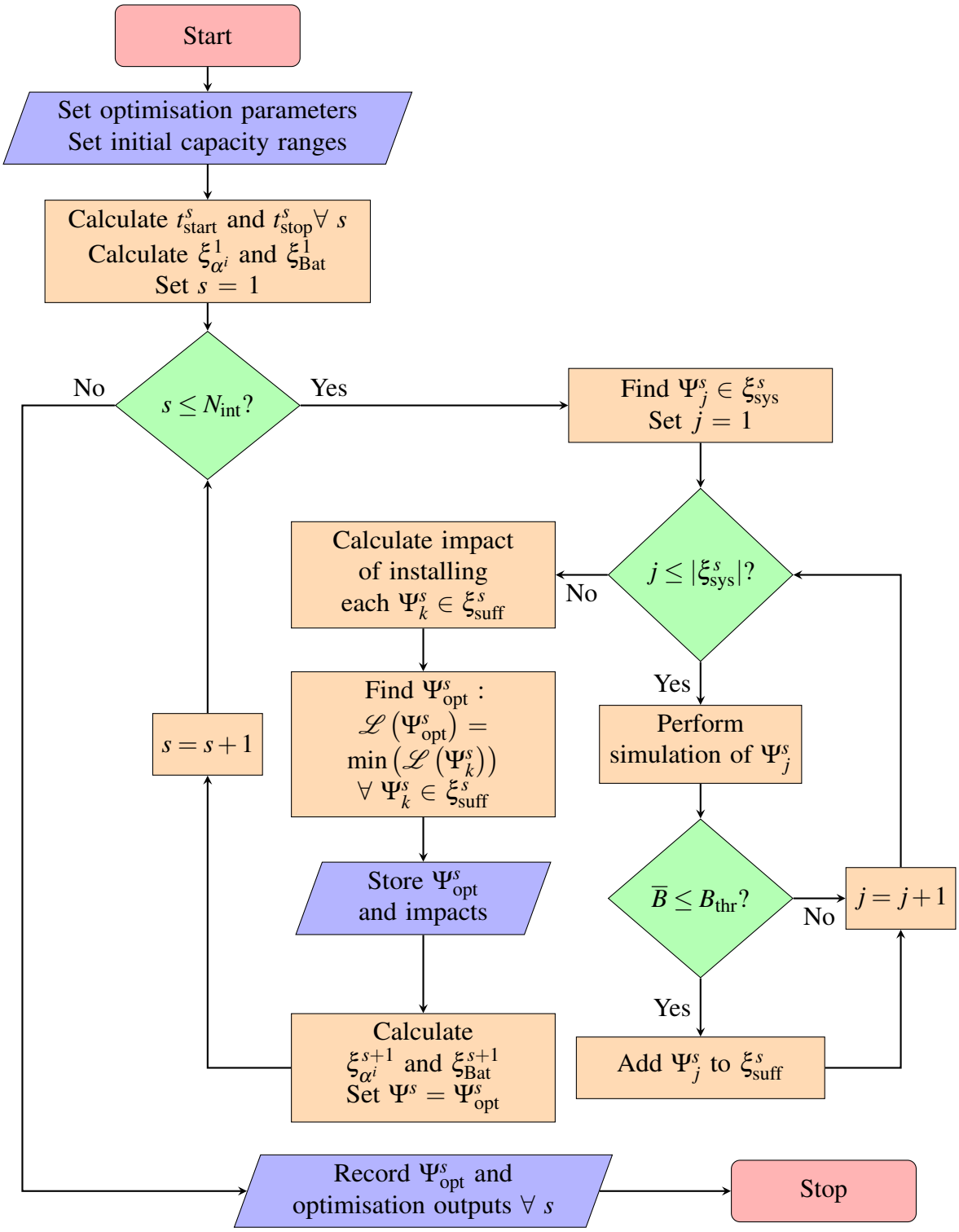


Fig. 6.3 Flowchart overview of the optimisation process.

6.5.3 Optimisation outputs

The optimisation outputs are recorded for each system Ψ^s. They give the user information about the capacities of the system necessary to be installed at $t = t^s_{\text{start}}$ and about the impacts and performance of the system at $t = t^s_{\text{stop}}$, for example the energy generated by system components, the financial and environmental costs and the blackout proportion. A summary of the outputs of the optimisation process is given in table 6.2; for further assessment, the user can take the results of the optimisation process to define a system in the simulation process. This would give an hourly analysis of the performance of the optimum system over its lifetime and would complement the aggregated lifetime values yielded by the optimisation process.

6.5.4 Advantages and limitations

An advantage of this optimisation process is that it mimics the real-life considerations of developers planning minigrid systems. A system designed to perform for a set period of time can be relied upon to deliver a service to the community, ensuring the developer a steady revenue stream over that period, and then upgraded as necessary to perform satisfactorily until the next evaluation. Depending on the nature of the developer this time period could be longer or shorter: businesses, for example, may wish to reevaluate systems more frequently to identify ways to increase energy consumption and revenue, but government agencies may have a longer-term view in line with wider development targets.

Furthermore, the interval-based approach reduces the risk in the prediction of future electricity usage. Estimating the future demand of the community is critical in designing a well-optimised system and estimates over shorter timescales are likely less likely to deviate significantly from predictions over longer time periods, which may be subject to unforeseen events. Selecting systems based on their short-term performance, and allowing for long-term increases in capacity, allows the system designer to reduce oversizing and tailors the system

Table 6.2 Outputs generated for each interval of the optimisation process.

Optimisation output	Description
System capacity	
Renewables capacity	Total capacity installed for each source, α^i
Battery storage capacity	Total installed capacity of batteries, $S_r(t_{\text{start}})$
Final battery capacity	Capacity of the battery after the interval, $S_r(t_{\text{stop}})$
Diesel capacity	Capacity of diesel backup generator
Blackout proportion	Average blackouts experienced, $\overline{B}$
Performance (kWh)	
Direct energy	Total energy supplied by renewables
Grid energy	Total energy supplied by the grid
Storage energy	Total energy supplied by battery storage
Grid storage energy	Total battery storage energy originating from the grid
Diesel energy	Total energy supplied by diesel backup generation
Unmet energy	Total energy demanded during blackouts but not satisfied
Discounted energy	Total energy supplied after discount rate is applied
Financial ($)	
LCUE	Levelised cost of used electricity (per kWh), $\mathscr{L}(\Psi^s)$
Off-grid system cost	Total discounted cost of off-grid system components
Grid cost	Total discounted cost of grid electricity
Diesel fuel cost	Total discounted cost of diesel fuel
Kerosene cost	Total discounted cost of kerosene for lighting, K_{C}
Environmental ($\text{kgCO}_{2\text{eq}}$)	
Off-grid system GHGs	GHG emissions embedded in off-grid components
Grid GHGs	GHG emissions from grid electricity
Diesel GHGs	GHG emissions from diesel generation
Kerosene GHGs	GHG emissions from kerosene for lighting, K_{GHG}
Kerosene GHGs avoided	GHG emissions mitigated by reducing kerosene, $M^{\text{K}}_{\text{GHG}}$
Total GHGs	Cumulative GHG emissions from all sources

to the present needs of the community. It may also be the case that incrementally increasing the system capacity allows a developer to take advantage of falling system component costs, which are possible to include in the CLOVER model.

The user should be aware that this method may not deliver the most effective long-term solution. A system that is the result of two optimisation intervals, Ψ^2_{ex}, may not be the same as a system optimised for one interval of twice the duration, Ψ^1_{ex}, as the performance of the first system installed for Ψ^2_{ex} influences the installation requirements of the second. If the

load profile changes significantly, for example from demand mainly occurring during the evening to mainly during the daytime, a capital investment in the first interval of Ψ^2_{ex} may not be fully utilised during the second interval. This could increase the costs of the system by adding new capacity or encourage the designer to continue investing in the less suitable technology, becoming locked-in and making Ψ^2_{ex} less effective. On the other hand, significant amounts of generation capacity in Ψ^1_{ex} could go unused. For example, if the user expects demand to grow rapidly, this could potentially waste resources as they go underutilised initially and degrade before they can be fully exploited. In this case it would have been more effective to use two intervals and install Ψ^2_{ex}.

It is imperative that the user appreciates the nature of optimisation process when designing systems. Many situations will not allow the flexibility for issues such as these to manifest, for example if intervals must be of a given length to conform to a business plan or government strategy, but where these constraints do not exist the user should demonstrate adequate acknowledgement of the implications of the optimisation process. If desired, the user could exploit these features to analyse the impact of the most effective rural electrification strategies under different conditions and constraints.

6.6 Conclusions

6.6.1 Summary of the model

In this chapter I have outlined the simulation and optimisation framework used by the CLOVER model. I presented how energy generation in the model, including renewable sources, grid electricity with a quantifiable amount of uncertainty of supply, battery storage, and backup diesel generation to reduce the extent of blackout periods. The user is therefore able to select any combination of these generation technologies for consideration in the

minigrid system to understand the potential benefits and drawbacks of using each generation source, or a combination of them.

I presented a novel approach to modelling energy demand based on previously described processes from the literature [70] and chapter 5 and also by introducing the potential for device ownership, and hence the aggregated load of the community, to increase over time. Considering both the increase in the number of households with access to a connection to the system and increasing device penetration as the community becomes more wealthy, the model is able to reflect the effects of economic development parameterised by the user. Furthermore, in addition to simulating the demand for electricity, the model also considers the usage of kerosene lamps by the community during times when power is unavailable which allows us to quantify the kerosene mitigation potential and, importantly, the resultant cost and GHG savings made possible by supplying electricity for household lighting.

The minigrid simulation process that I describe provides an overview of the computational steps taken to simulate the technological performance of the system during the considered time interval. I also listed the outputs of the simulation model in three distinct categories: initialisation stage outputs, which are calculated before the simulation is performed; iteration stage outputs, describing the hourly performance of the system during the simulation time interval; and finalisation stage outputs, resulting from post-simulation analysis and the usage of backup power supplies. These outputs can be further analysed by the user to understand the operation of the system over time, for example diagnose where power is sourced from and when it is unavailable, and also to quantify lifetime averages of the system performance to compare minigrids of different compositions, for example using the blackout percentage $\overline{B}$.

Finally, I described the novel multi-stage optimisation process. Using two criteria, the blackout percentage to determine whether or not a minigrid system is sufficient enough in providing reliable power and the LCUE to identify the least-cost system, allows the model

to suggest the system which supplies both reliable and affordable power to the community. Using the reoptimisation steps and considering potential future systems with greater capacities allows the user to investigate the effect of increasing community energy demand and better reflects the usefulness of the system over its lifetime. After the optimisation process, the user can analyse the lifetime performance of the system in terms of the recommended generation and storage capacity, the energy provided by each source, and financial and environmental metrics including the lifetime LCUE and GHGs. This optimisation process, and these performance metrics, will allow us to assess various electrification strategies for communities in rural India in chapter 7.

6.6.2 Modelling the GHG mitigation potential of PV

The goal of developing this modelling framework is to assess the potential of PV technologies to mitigate GHG emissions. As we have seen in chapter 3 and the literature, it is possible to simulate off-grid minigrid systems and to calculate their costs and embedded GHG emissions however we have seen previously how it is also important to include other factors to understand the overall impact of the deploying a PV minigrid. The system must be reflective of the reality of rural electrification; in addition to PV as a generation source, I have also considered the usage of diesel for backup power and an unreliable grid network, both of which may either be present at the time of the system being installed or may be introduced over the system lifetime. By integrating these into the modelling framework the CLOVER user can choose to assess how these generation sources can work together, or in opposition, to provide power to the community whilst accounting for their costs and embedded GHGs.

In chapter 5 I identified the need to consider the usage of kerosene lamps in assessing the total GHG emissions, and mitigation potential, of an electricity system and for this reason I have integrated it into the CLOVER modelling framework. Communities with no access to electricity produce significant GHG emissions from kerosene lamps and the

mitigation of this should be considered as a motivating factor in providing electricity. This benefit could be treated similarly to, for example, replacing a diesel generator with a PV system or by assessing those two generation sources as options for a village without access to electricity. Understanding and quantifying the benefit of deploying a minigrid system in terms of its long-term cost and GHG emissions reductions can reframe rural electrification as an investment, rather than an expenditure.

Finally, I discussed in chapter 3 that considering a single simulation period of 20 years would potentially be unrealistic in modelling long-term system performance. Simulating increasing electricity demand, possible using CLOVER, allows the user to include a reflection of the economic growth that could stimulate this and can help the user understand the long-term requirements of the community. Furthermore, using the multi-stage optimisation process facilitates designing appropriately designed systems to avoid oversizing and, in doing so, could decrease the costs and embedded GHGs of potentially superfluous system components. This will allow systems reliant on any generation technology to reduce redundancy and help to supply communities with power at a lower cost and with reduced GHG emissions.

In chapter 7 I will demonstrate a potential usage of the CLOVER modelling framework in assessing the impact of several rural electrification strategies in meeting the needs of a community in rural Uttar Pradesh, India which previously had no access to electricity. Using the findings of chapters 3 and 5 and the processes described in this chapter I will present the results of using minigrid systems for domestic and commercial energy access using on- and off-grid minigrid systems composed of PV and battery storage, diesel generation, and a hybrid combination of the two. I will further consider the impacts of integrating an unreliable grid network and evaluate the benefits of supplying electricity in comparison to incumbent energy sources, including kerosene lamps. The analysis presented in chapter 7 will provide a representative overview of the potential of the CLOVER model to assess the performance

and suitability of minigrids for rural electrification and, in doing so, the demonstrate the potential of PV to mitigate GHG emissions.

Chapter 7

Impact of using minigrids for energy access in rural India

Acknowledgement of contributions

Surabi Menon (ClimateWorks Foundation) organised and participated in the discussions with stakeholders in Delhi in July 2016. Arunabha Ghosh and Abhishek Jain (Council on Energy, Environment and Water), Deepak Gupta (Shakti Foundation), Disha Banerjee (Smart Power India) and Chandra Bhushan (Centre for Science and Environment) gave input through interviews to the direction of research. Rishab Shrestha installed smart meters from which the reliability of the electrical grid was calculated and provided information for the utilisation of commercial devices, with work overseen by Clementine Chambon, Amit Saraogi and Philip Sandwell. Jenny Nelson and Ned Ekins-Daukes advised on the direction of research and supervised the work. All other work is that of the author.

Previous presentation of this work

Sections of this work have been published as an article in *Energy Procedia* [225]:

Sandwell P, Ekins-Daukes N and Nelson J. What are the greatest opportunities for PV to contribute to rural development? *Energy Procedia*. 2017; **130**:139-146. DOI:j.egypro.2017.09.416. Work from this article is reproduced with permission [112].

Sections of this work were presented as a poster presentation:

Sandwell P, Ekins-Daukes N and Nelson J. What are the greatest opportunities for PV to contribute to rural development? At *SNEC 11th International Photovoltaic Power Generation Conference & Exhibition*, Shanghai, China, 17–20 April 2017.

7.1 Introduction

7.1.1 Overview

In this chapter I will demonstrate an example usage of the CLOVER modelling framework and bring together the findings of the previous chapters to consolidate our understanding of the suitability of PV minigrids for rural electrification. Informed by my previous conclusions I will use the processes described in chapter 6 to integrate the data and modelling techniques to provide a more complete analysis of the potential of PV to effectively mitigate GHG emissions. In particular the ways in which I consider growing demand profiles, use the multi-stage optimisation process, integrate a weak grid network, assess the benefits and drawbacks of battery storage charged from the grid, and quantify the ability of systems to mitigate existing incumbent energy sources provide a novel analysis and contribution to the literature.

A graphical overview of this chapter is given in fig. 7.1; in this work I focus on the case of India, but a similar process could be used to investigate rural electrification in other countries. In section 7.1 I provide a summary of the research presented previously and outline the aims and objectives of this chapter. In section 7.2 I provide an overview of the modelling process including the minigrid configurations I consider, a description of the community and their existing energy access, the types of demands I investigate and the simulation and optimisation parameters I use. In section 7.3 I analyse off- and on-grid minigrid systems for domestic or commercial uses in terms of their LCUEs and GHGs and discuss the impact of their use. In section 7.4 I assess the impacts of off-grid minigrids to reduce total expenditure and GHGs by mitigating the usage of kerosene in domestic settings and incumbent diesel generation for commercial purposes. In section 7.5 I explore the breakeven distances of off-grid PV minigrids in comparison to grid-connected hybrid systems for a range of community sizes and investigate the effect of introducing a carbon price. Finally, in section 7.6 I summarise

my findings and evaluate the impact of using PV minigrid systems for energy access in rural India.

7.1.2 Assessment criteria

In this chapter I use life cycle assessment to evaluate the viability of PV minigrid systems and, as in previous chapters, I will use several performance indicators to assess their financial and environmental impact. During the simulation and optimisation I use the proportion of time that the system fails to provide power, the blackout percentage $\overline{B}$, as the sufficiency criterion and the levelised cost of used electricity (LCUE) as the optimisation criterion. As before, the LCUE is calculated in US dollars per kWh ($/kWh) using the process described in section 2.5.3. The LCUE is considered using costs incurred and electricity provided from all sources cumulatively.

I use the total GHG emissions, measured in tonnes of CO_{2eq} or tCO_{2eq}, as the primary measure of the environmental impact of the system. In contrast to the earlier usages of emissions intensity to judge performance, which captures only those emissions from electricity production, I use the cumulative GHGs which allows us to integrate the GHGs from kerosene lamps more effectively which would not be considered when assessing the impact of electricity alone. The GHG emissions associated with each system are calculated using the processes described in section 2.6.2.

To assess the impact of minigrid systems in mitigating the usage of existing energy sources, namely kerosene lamps and incumbent diesel generation, I present the findings in terms of their potential to reduce the costs and GHGs of community members in terms of per capita expenditure per year ($/year) and per capita emissions per year ($kgCO_{2eq}$/year). This will allow us to evaluate the effectiveness of these interventions at the individual level, as well as the system level as before. I further present these impacts in terms of the total reductions

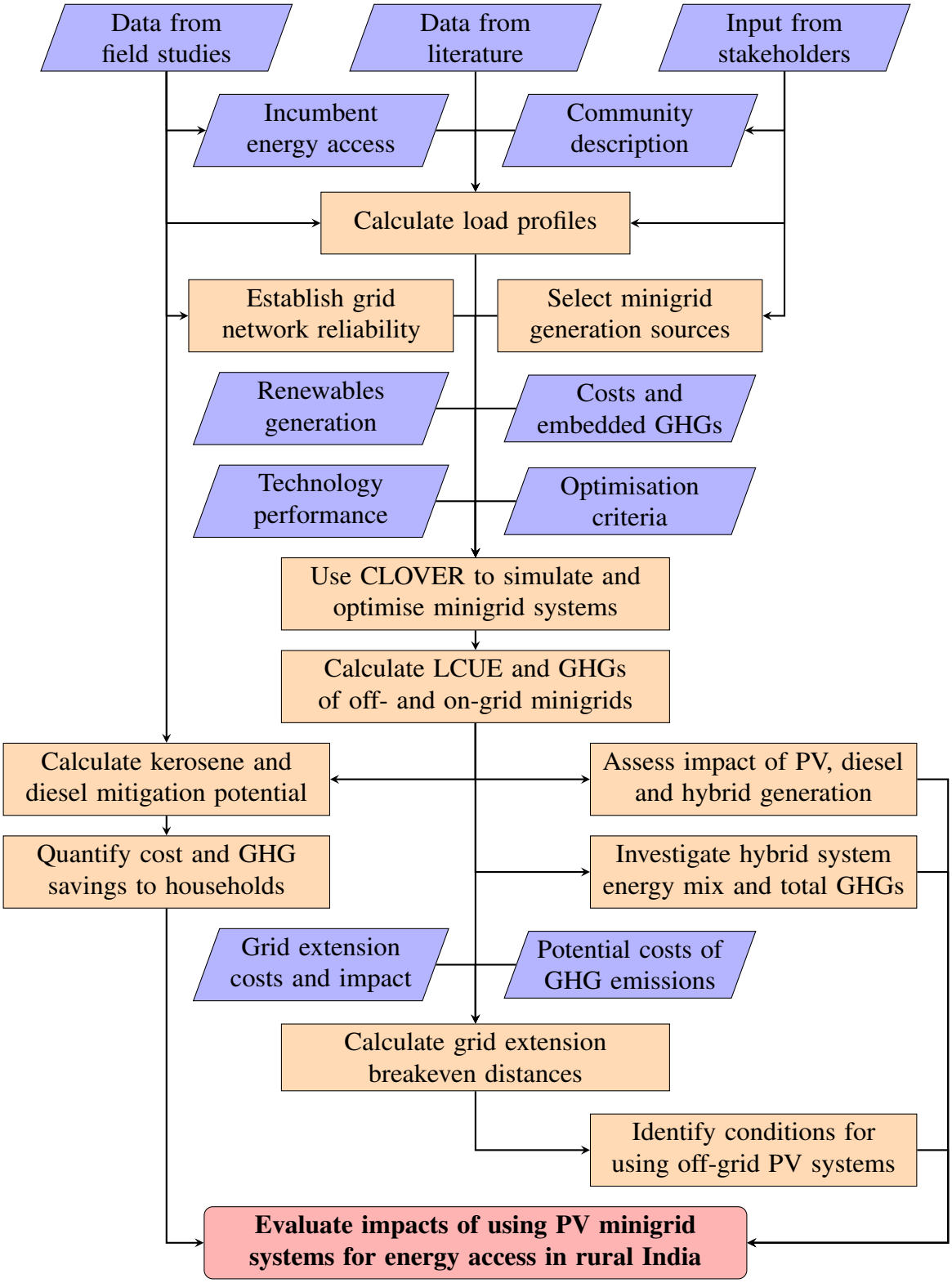


Fig. 7.1 Graphical overview of chapter 7.

in expenditure and GHG emissions available when using minigrid systems compared to using the incumbent energy sources.

Finally, I calculate the grid extension breakeven distance for off-grid PV systems compared to on-grid hybrid systems using the process outlined in section 2.5.4. This allows us to assess the distance from existing infrastructure at which it is more beneficial to install an off-grid system rather than extend the grid network. I further include the effects of policies equivalent to introducing prices on carbon, described in section 2.6.6.

7.1.3 Summary of previous work

In chapter 3 I found that off-grid PV systems can provide sustainable and reliable power to rural communities and can successfully mitigate GHG emissions when compared to either diesel generation or grid electricity. Mature technologies outperform their emerging counterparts and, whilst OPV may be effective if the technology performance improves and costs decrease, CPV is unlikely to be selected for rural electrification owing to its comparatively high reliance upon battery storage. I have assessed the potential of innovative designs of CPV modules in chapter 4 but, as this PV technology is unsuitable for deployment in rural minigrid systems, I will not consider it in this chapter. I will focus instead on the dominant PV technology, c-Si, for rural minigrids owing to its wide scale of deployment and its significant and continuing cost reductions [116].

I identified in chapter 3 that using different load profiles, specifically in providing household energy services and for supplying additional income generating activities, can have an impact on minigrid system design but this was not explored in depth. To address this I incorporated the results of data gathered from fieldwork studies in chapter 5 and integrated the results into stochastic demand simulations to capture the effects of variability, both day-to-day and seasonally, in the load demanded by the community using a previously-described

process [70]. This was further developed in chapter 6 where I include increasing demand for energy services resulting from economic development.

Furthermore, chapter 3 highlighted that comparing PV minigrids to diesel generation and grid extension does not fully capture their GHG mitigation potential and the reduction in kerosene usage should also be included. The baseline of incumbent energy access provided by chapter 5 provides an opportunity to assess that impact in the current chapter. By integrating an unreliable grid network, which was earlier taken to be completely reliable as an idealistic simplification in chapter 3, I am able to better inform potential grid extension plans in this chapter by including a supplementary local minigrid to augment the electricity provision to an acceptable level.

The modelling process used in chapter 3 relied on a single 20-year simulation period; whilst this is recommended for LCAs of PV installations [16] it would be unlikely that an electricity system designed in such a way would be sufficient to successfully meet the needs of a rural community in the long term, particularly if demand for energy services is expected to grow. For this reason I have used a multi-stage optimisation process, described in detail in chapter 6, to help address this issue and investigate the potential of systems to expand modularly in response to increasing demand.

7.2 Modelling process

7.2.1 Introduction

Overview

The goal of this chapter is to assess the impact of various minigrid configurations in meeting the energy needs of a rural community using the CLOVER modelling system described in chapter 6. I appraise energy systems using the same assessment criteria for each to investigate their relative benefits and drawbacks and to compare their suitability in terms of providing

reliable, affordable and sustainable energy access. My ultimate aim is to assess the GHG mitigation potential of PV as part of a minigrid energy system and, in order to do this, I must appreciate the conditions under which it would be considered a viable electrification option and when other options would be considered as more practical. In this section I outline the community electrification scenarios in this chapter and the types of demand being met, and throughout this chapter I will draw on the findings and conclusions of previous sections of this work. The codes used to generate these results are available in appendix B and a compilation of the parameters used in the modelling process is given in appendix D.

Stakeholder inputs

In July 2016 we conducted interviews in Delhi, India with stakeholders representing organisations with interests in providing energy access to rural communities in India. These were facilitated by Surabi Menon of the ClimateWorks Foundation, an NGO based in the United States which mobilises philanthropic capital with the aim of reducing GHG emissions, including those associated with rural energy access. During the interviews the modelling framework and research direction of the work described in this chapter were discussed to understand the interests and needs of practitioners, funding agencies and advocacy groups with respect to the most important challenges facing rural communities. The stakeholders described a particular interest in the potential of minigrid systems to satisfy increasing amounts of electricity demand as the village develops, how systems could mitigate incumbent energy sources such as kerosene lamps, the effect of an unreliable grid network on system reliability, and how to provide electricity services with the lowest amount of cumulative GHG emissions. The opinions that were shared were used to inform the most impactful directions for the research; all of the analysis presented in this chapter was conducted independently of any commercial interests and no conflict of interest exist between the academic goals of this work and the objectives of any of the organisations interviewed.

7.2.2 Minigrid configuration

Overview

In this chapter I consider the use of several configurations of minigrid systems defined by the type of demand they aim to meet, their energy generation technologies, whether or not they have a connection to the national grid network, and whether or not this connection allows the storage of grid power in the battery system. A summary of these systems is shown in table 7.1.

Table 7.1 Overview of system configurations for on- and off-grid systems meeting demand and commercial demand types.

(a) Generation sources available to on- and off-grid systems.

System	Generation type			Grid		Notes
	PV	Storage	Diesel	Supply	Charging	
Off-grid						Independent of grid
PV	✓	✓	✗	✗	✗	Similar to chapter 3
Diesel	✗	✗	✓	✗	✗	Dispatchable generation
Hybrid	✓	✓	✓	✗	✗	Diesel as backup
On-grid						With/without grid charging
PV	✓	✓	✗	✓	✓ / ✗	Storage prioritises PV power
Diesel	✗	✗	✓	✓	✓ / ✗	Diesel backup for grid
Hybrid	✓	✓	✓	✓	✓ / ✗	All options available

(b) Devices available in domestic and commercial systems.

Device	Demand type		Notes
	Domestic	Commercial	
Fixed lights	✓	✓	LED lighting
Phone charging	✓	✓	Basic handset
Fans	✓	✓	Tabletop fan
Televisions	✓	✓	Low-energy LED TV
Refrigerators	✓	✓	Suitable for single household
Mill	✗	✓	Agroprocessing machinery e.g. rice husker
Workshop	✗	✓	Handheld tools e.g. for carpentry
SME	✗	✓	Home industry e.g. sewing machines

Off-grid systems

Off-grid systems are those which operate entirely independently of the national grid network. I take these to be similar to those used in chapter 3 which are composed of a central power source, battery storage if available, and a distribution network from the system hub to each household or business receiving electricity services. I investigate in this chapter three power supply options which are summarised in table 7.1 a). The first is electricity supplied by PV and storage, as considered earlier in chapter 3. This relies solely on locally-generated renewable power from solar PV which is either used directly by the community or to charge battery storage; as in chapter 3, I again consider the use of lithium ion batteries as the storage technology in this chapter. The second is diesel generation alone, which is dispatched under the conditions given in section 6.2.6 and prioritises the periods of greatest demand which will allow the diesel generator to be operated must efficiently and cost-effectively. This method is common in rural India where diesel generation is cheap and straightforward to operate. Finally, hybrid systems can use any combination of PV, battery storage and diesel backup generation that will meet the sufficiency and optimisation criteria under consideration.

On-grid systems

On-grid, or grid-connected, systems use power from the national network under the conditions given in section 6.2.3; as the reliability of the grid is insufficient to meet the needs of the community a local community minigrid system is used to augment the availability of power. One could consider this as a grid-backup system however, when low blackout percentages are required, then the minigrid supplies more power via local generation than from the grid and so describing the system deployed in the community as a backup may be misleading.

On-grid systems can either provide a direct power supply only or both a power supply and the charging of minigrid batteries. When each is available on-grid systems prioritise power supplied from the grid network, direct generation from PV, power from battery storage, and

finally diesel generation. When grid-charging of minigrid battery storage is available the order of prioritisation remains the same, and batteries are charged preferentially from PV generation and secondly from the grid, if permitted. Storing power from the grid can maximise the usage of cheap grid electricity but may require stronger technical and policy regulation: if a large number of communities were using the grid both for their immediate demand requirements and to charge batteries then the strain on the network would be increased and, if the demand for electricity at these times is not met by a sufficient increase in generation capacity, would make blackouts more likely to occur. This would have a particular impact in areas where communities are undersupplied by the grid already, such as in rural regions I consider. In this work I will analyse the usage of grid-storage minigrids without considering the effect that they may have on the national grid network although the conclusions I draw will be mindful of this issue.

Power distribution

I assume the systems use a low-voltage DC distribution network, which has a number of advantages: it allows for the safe transmission of power, minimises conversion losses as both PV and battery storage output DC power, and common devices such as LEDs and phone charging use DC power [35, 223]. Furthermore an increasingly large DC-compatible market is becoming available and new devices are being designed to take advantage of the efficiency of DC power including for productive, commercial and agricultural devices [231, 232]. The drawback of this, however, is that power from PV and battery storage must be converted to the appropriate transmission voltage, and AC power from diesel generators and the grid must be converted to DC, both of which suffer conversion losses. As the technologies governing these transitions are still under development and the ultimate costs are not yet known, I take it that these electric power converters have the same performance and costs [74, 233–235]. In reality these will vary and will depend on the systems being used but this simplification

allows for a fairer and more general comparison between the various power supply options in the absence of detailed technological specifications that would be possible in dedicated case studies. Further work could investigate any variation in using different current conventions.

Demand types

I consider two kinds of demand to be met by the minigrid systems and the devices available to each shown in table 7.1 b). Domestic systems are designed to meet the needs of households, with the devices I consider being similar to those made available in the simulations from chapter 5 and an improvement from those in chapter 3. These devices allow households in the community to use electric lights, charge their cell phones and use fans, and also the opportunity to use televisions and refrigerators.

Commercial systems include the additional provision of income-generating activities in a more detailed analysis that in chapter 3. The power requirements of rural businesses will vary extensively and so in this work I generalise the service demands into three categories. In order of decreasing power requirements I consider mills, representing any small-scale agroprocessing machinery such as rice huskers or grinding machines; mechanical workshops requiring tools such as for carpentry and vehicle repair; and SMEs, which could household industries using small equipment such as sewing machines or for making handicrafts. As with the domestic devices I consider the ownership of commercial devices on the basis of an average per household, but for the purposes of the simulation it is immaterial whether these devices are located in individual households or conglomerated, for example in a tailor shop. These two configurations may have an effect on the way that the local distribution is designed but, in the absence of a specific case study example, I assume that any differences in the two cases will have a negligible effect on the findings.

For both domestic and commercial demands I assume, where available, that the community uses high-efficiency devices which provide the same level of service but with lower

energy requirements that more traditional devices, for example using LED lights rather than incandescent bulbs. This would be preferable for minigrid designers as the same amount of generated electricity can serve a greater number of customers or provide more power to each, and increasing the usage of DC devices has been suggested as a key opportunity for off-grid systems to both reduce cost and provide superior levels of service [35, 76, 223, 231, 232].

In section 7.2.4 I describe in more detail how the electricity demand of the community is calculated. The total demand depends on many factors and therefore, for the purposes of comparability and reproducibility, the device usage in all of the domestic scenarios is considered to be the same, and similarly for the commercial scenarios. The ownership each device type and how quickly this grows will have an effect on the optimum system required to meet the demand: if LED light ownership is high and fan ownership is low, for example, the overall load profile will be different than the reverse case, and furthermore if fan ownership grows far more quickly then the seasonality of the load profile will change from highest in the winter to highest in the summer, as we saw in chapter 5. In this work I discussed the potential growth scenarios with the stakeholders to obtain reasonable assumptions of increases of device ownership over time in line with their expectations of economic development; these discussions resulted in the parameters chosen to model device ownership over time shown in appendix D.

7.2.3 Scenario

Community description

Throughout this chapter I consider a community located in a rural area of Bahraich District, Uttar Pradesh and representative of the villages surveyed in chapter 5. A community size of 100 households serves as the functional unit as it allows the application of the results found here to larger communities whilst also being representative of the size of many villages and hamlets in rural Uttar Pradesh. I assume all 100 households receive electrification

via the minigrid system at the start of the analysis period; whilst it may not be the case that every household receives a connection at the same time, or that every household in a community receives a connection at all, the results of this work can be extrapolated to fit realistic expectations of how connections in a community will grow. I assume that the average occupancy of each household is seven people; this is lower than the average I found in chapter 5 but is more representative of Bahraich District and Uttar Pradesh as a whole [55] and so, for generalisability, I chose to use this value.

Incumbent energy access

I take it that the community which receives the minigrid has no prior access to electricity and households rely on kerosene lamps for their lighting needs. This assumption, and the data used in the model for it, is taken from the survey data described in chapter 5. In practice some households may already have access to solar home systems but I take it that the usage of these will be replaced by a superior level of service from the minigrid.

Households continue to own kerosene lamps after the minigrid system is installed. I assume that whenever electricity is unavailable when lighting is required then the households use their kerosene lamps as a backup, but otherwise they go unused. This is similar to what I observed in chapter 5 that candles were owned as a source of lighting but used only when other sources were unavailable. As we saw in chapter 5 it may be inaccurate to assume all kerosene usage will be removed when an alternative energy source is available; the cost and GHG mitigation potential I present in this chapter will therefore be an upper estimate of the impact of the system. Providing a reliable electricity service will help make this transition more likely but other interventions may also be required in order for it to happen.

If kerosene lamps are used then the expense and GHGs resulting from their usage are included in the total lifetime impact of the system. Owing to the high cost and GHGs of

kerosene I will show in later sections that it is typically desirable for a system to mitigate their usage as much as possible.

Grid reliability

As reported by Jain et al. [52], and also anecdotally by respondents in chapter 5, grid services fall short of user expectations and power is available for only a minority of the time with frequent and unpredictable blackouts. In order to assess the viability of grid-connected minigrid systems I must first understand and be able to characterise the reliability of grid service in rural regions of Bahraich District.

To address this issue Philip Sandwell, working in collaboration with Clementine Chambon and Amit Saraogi of Oorja Development Solutions Ltd., planned the collection of data from sites with a grid connection in Mirjapur Chauraha, a small market town on the outskirts of the district capital. Smart meters were installed by Rishab Shrestha, working for Oorja Development Solutions Ltd., in three businesses in the area and the power usage by these businesses was monitored remotely from March to July 2016. Data on instantaneous voltage, current and power consumption was recorded by the smart meters at three-minute intervals and transmitted to a remote server. After the data was collected Philip Sandwell analysed each hour of the monitored duration and calculated the average number of three-minute intervals, of a maximum of 20, in which power was available and then assigned each hour of the duration to its corresponding hour of the day and took the average of these; this represents the probability that the grid was available at a given hour of the day. I assign these values as γ_H for the hour of the day H and, following the process given in section 6.2.3, derive the grid availability profile $G(t)$.

As explained section 6.2.3, I assume that blackout periods occur independently, at random, and depend only on the time of day. I also assume that the reliability of the grid is the same each day and does not exhibit seasonal variation; in reality this may not be the case as energy

demand and generation, especially from renewable sources, will vary throughout the year and will change the likelihood of grid blackouts occurring. With only around nine hours of electricity supply per day, the reliability of the grid is low enough to merit the introduction of a minigrid system to augment the supply to acceptable levels; this is what I consider via on-grid systems throughout this chapter.

7.2.4 Energy demand

Device utilisation

The utilisation profiles derived and used in chapter 5 were also incorporated into this work using the processes described in section 6.3.3. Device utilisation varies throughout the day and throughout the year depending on the desire for energy services: I show this in fig. 7.2 where the average total number of hours per day each device i is used, U_D^i, is shown for every day D of the year. The commercial load profile considered in this work also contains all of household energy services included in the domestic profile under the assumption that a minigrid installed with the goal of energy access would not omit the needs of households from its design; in fig. 7.2 these energy uses are segregated for clarity.

The smooth variation in the profiles is an artefact of the interpolation process used to generate the utilisation profiles. The exception in fig. 7.2 is the utilisation of the fan, shown in pink, as I derived this from weather data rather than from data derived from surveys of from the literature. I use the same utilisation profiles as in chapter 5 for domestic demand but the commercial demand is a new addition. These utilisation profiles were suggested by Rishab Shrestha during his work with Oorja Development Solutions Ltd. in which he interviewed local business owners on their current energy use and the seasonalities of their enterprises. He found their operations were seasonally variant, especially for agroprocessing, with heightened periods of activity outside of the main growing seasons, from March to July and October to January. Other businesses were also more active outside of the growing

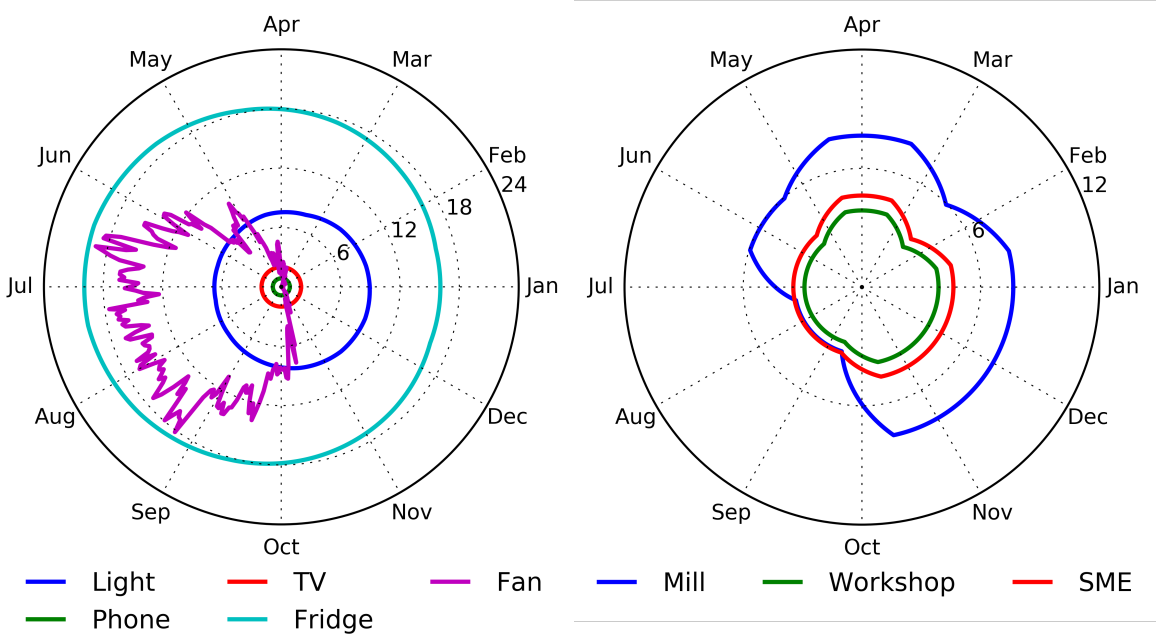


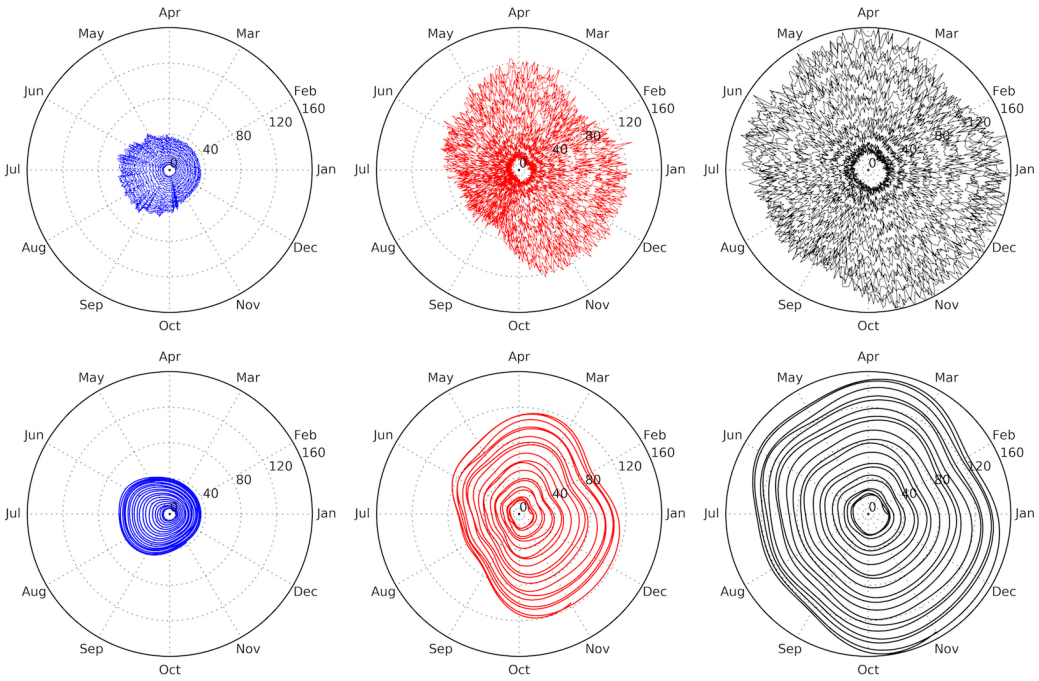
Fig. 7.2 Utilisation for domestic (left) and commercial (right) devices, shown as their total number of hours of use per day (radial scale), throughout the year (polar axis). The commercial load profile used in this work also contains all of the domestic devices, but these have been segregated for clarity.

seasons as business owners often had their own crops requiring attention. I have integrated these findings as the utilisation profiles for commercial devices, shown in fig. 7.2.

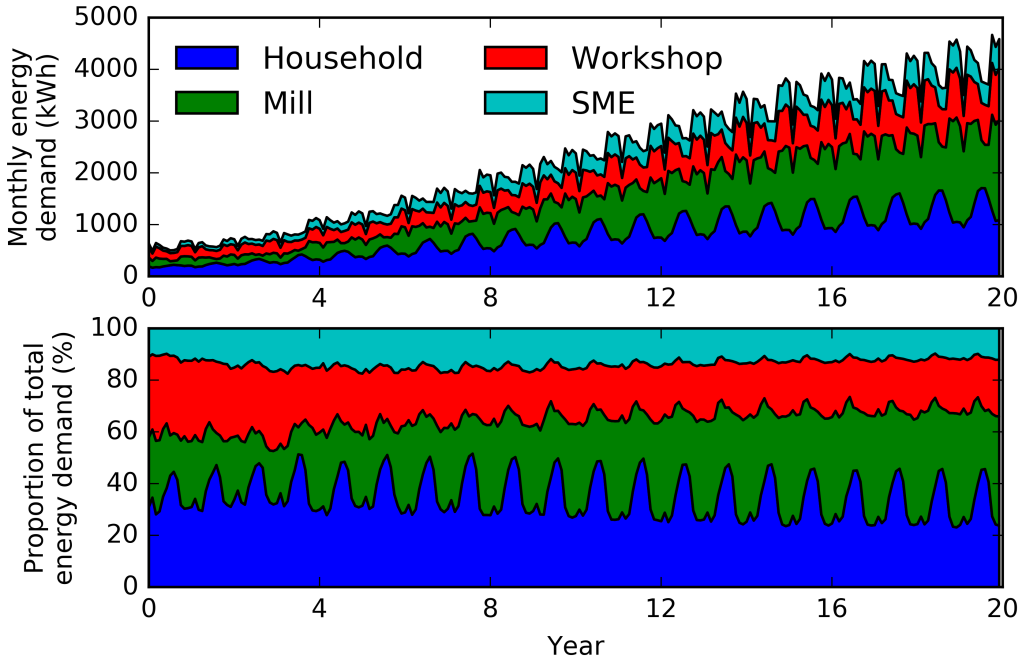
Increasing domestic and commercial energy demand

I model the demand for domestic and commercial services using the processes given in section 6.3 where the combination of utilisation profiles, device ownership and statistical estimation is outlined and yields a total electricity demand profile. A description of the parameters used to generate the load profiles used in this chapter is given in appendix D and the resulting loads are displayed in fig. 7.3.

The seasonality of the total resultant load can be seen in fig. 7.3 a) with the load profiles used in the simulation shown on the top row and the average load, without the application of the statistics governing the fluctuating demand, shown on the bottom row. Domestic demand,



(a) Cumulative daily energy demand (radial axis) throughout the year used in the simulations (top) and daily averages (bottom) showing domestic (blue), commercial (red) and total (black) loads. Adapted from Sandwell et al. [225].



(b) Breakdown of monthly energy demand growth (top) and as a proportion of total demand (bottom) for households (blue), mills (green), workshops (red) and SMEs (cyan).

Fig. 7.3 The electricity demand of the community used in the simulation a) as cumulative daily amounts and averages displaying seasonal variation and b) as monthly amounts and as a proportion of the total.

in blue, has its highest daily energy values between June and August, owing to the increased usage of fans and refrigeration, whilst commercial demand follows the agricultural seasons and highest in April to June and October to January. Commercial demand is greater than domestic demand as the power requirement of each device is greater. In all cases the average daily energy demand increases over time, shown here as spiralling out from the centre: this is caused by my assumption that the community will have access to more devices over time as the local economy develops and households have more opportunities to invest in new energy services.

The monthly energy demand over time, shown in fig. 7.3 b), demonstrates this growth. Over the lifetime of the system the energy demand grows from around 500 kWh per month to more than 4500 kWh per month, owing mainly to an increase in commercial demand as the village economy develops and more households can afford access to income-generating appliances. The proportion of energy demand accounting for each demand segment remains relatively constant from year to year, albeit with an annual periodicity of high domestic demand in the warmest periods coinciding with times of lower commercial demand.

7.2.5 Simulation and optimisation parameters

I consider a system lifetime of 20 years for comparability to other studies, including that of chapter 3. Each lifetime simulation is divided into five periods of four years each and for which I perform the simulation and optimisation processes described in sections 6.4 and 6.5. The four-year period was chosen as a reasonable amount of time that a minigrid operator could plan for in advance: a shorter period may increase the costs to the company as equipment would need to be regularly shipped to potentially remote locations, and minigrid developers may be reluctant to make repeated installations at the same site and would prefer to invest equipment for new communities, for example. A longer time period, however, could present a greater risk in correctly sizing the minigrid components. Stakeholders agreed

during the interviews that this time period would be appropriate and would, for example, suit their typical funding cycles for energy access projects. Using a different time period for simulations, which would be possible using CLOVER, would be likely to have an effect on system design: a shorter time period may incentivise the use of diesel generators, for example, whereas longer periods of consideration may result in investments in PV being selected by the optimisation process as more worthwhile. A sensitivity analysis of the length of time periods could be performed but owing to the time limitations of the work, this was not investigated.

I select the minigrid configurations for each optimisation trial and use the blackout percentage, $\overline{B}$, as the sufficiency criteria throughout the system lifetime. Sufficient systems are screened from all of the simulated combinations of generation capacities and the system with the lowest LCUE in each period is selected as the optimum and its outputs are recorded. By varying the allowable blackout percentage I am able to analyse the impact of system reliability on, for example, the LCUE and GHG emissions and use these performance indicators to assess the viability of the minigrid configurations.

For comparability between the various configurations of minigrid systems I use the same domestic and commercial demand profiles for all systems. I also use the same weather profiles, which would otherwise affect the performance of PV and the utilisation of devices such as fans, and the same grid profile $G(t)$ for all on-grid systems. This allows us to fairly compare the performance of minigrid systems in meeting the needs of the community and ensures repeatability between the simulation and optimisation trials.

7.3 Analysis of minigrid systems

7.3.1 Introduction

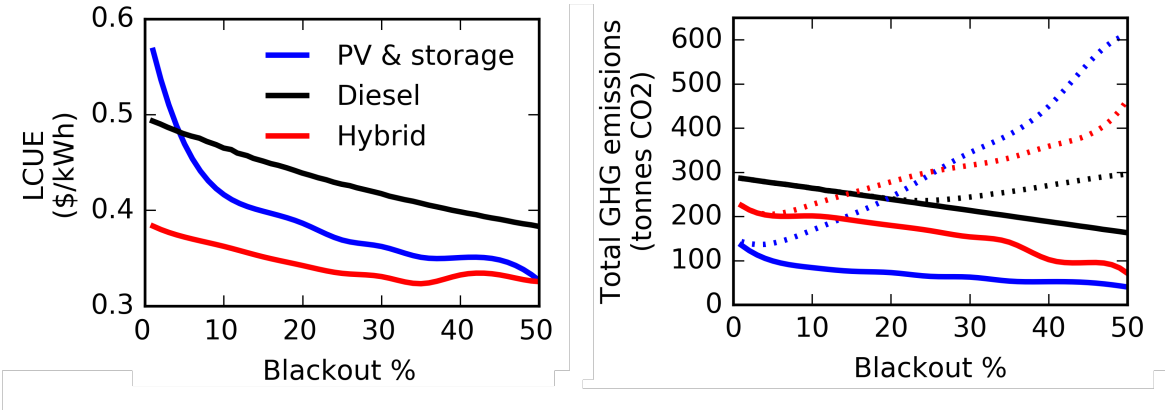
In this section I consider the impact of two types of minigrids: those operating independently of the national grid network and those with a connection to an unreliable grid supply. I assess both of these by addressing first the impacts of systems which are designed to meet domestic household demands only, and second with the additional commercial loads that would provide an economic benefit to the community. In each of these scenarios I simulate and optimise the use of three generation types: PV and battery storage, diesel generation, and a hybrid system composed of the two. Furthermore, I assess the impacts of both off-grid minigrids and those with a grid connection.

Here I display the LCUE of each configuration at blackout percentages in the range 1–50% and the total GHGs emitted over the lifetime of the system. Solid lines correspond to impacts related to the electricity system and, for the GHGs, this can be interpreted as a proxy for the system emissions intensity. Dotted lines show the additional impact of kerosene usage for lighting when electricity is unavailable. The results for off-grid systems are shown in fig. 7.4 and those for on-grid systems are shown in fig. 7.5.

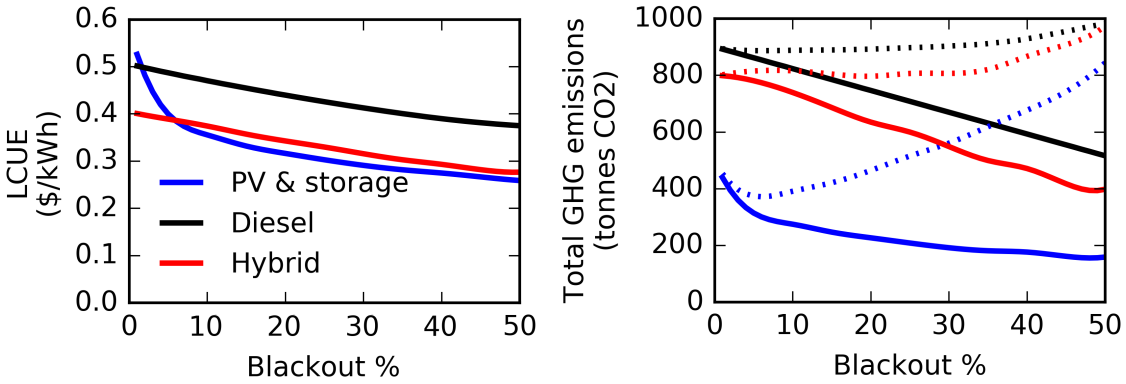
7.3.2 Off-grid minigrids

Domestic systems

The impacts from domestic off-grid systems are shown in fig. 7.4 a). I calculate that, despite the high initial capital investments, PV minigrids can offer lower LCUEs than diesel systems at almost all levels of reliability. Systems with very low blackout percentages, however, exhibit higher LCUEs as a result of the necessary but comparatively high investment in the system. With negligible GHGs emitted during operation, the emissions intensities of PV systems with blackouts percentages of 10–50% are in the region 400–450 gCO_{2eq}/kWh and



(a) Impacts of off-grid minigrids for domestic electricity access.



(b) Impact of off-grid minigrids for commercial electricity access.

Fig. 7.4 The LCUEs and GHGs (solid lines) of a) domestic and b) commercial off-grid systems supplied by PV & storage (blue), diesel generators (black) or a hybrid (red) and the additional impact of kerosene lamps (dotted lines). Adapted from Sandwell et al. [225].

far lower than the diesel alternative; this is reflected in the relatively low total GHGs incurred from system deployment. As in chapter 3, this considers the electricity used as part of the off-grid system and as a result is expectedly higher than for utility-scale PV installations.

Diesel systems yield the highest LCUEs, other than at the highest levels of service reliability, and incur the greatest emissions intensities for the power they provide. Hybrid systems, meanwhile, take advantage of PV generation during the day and diesel power when required at night, allowing them to keep costs low. By relying very little on storage, lowering both initial and replacement costs, they can provide the lowest LCUEs at all reliabilities.

Their emissions intensities are lower than those for diesel generation but are significantly higher than for PV systems.

The inclusion of kerosene lighting as a backup energy source has a significant impact on the total GHGs emitted during the lifetime of the system. For systems with blackout percentages of 20% or lower, the PV and storage systems are reliable enough to mitigate most of the kerosene usage and provide a net benefit. Above this blackout percentage, however, PV systems perform comparatively worse than diesel generation: outage periods for the former occur in the evening when kerosene lamps are in highest demand, whilst outages for the latter occur typically during the day for domestic demand.

The reliance on several power sources in a hybrid system significantly reduces LCUE but comes at a cost. Despite their GHG emissions from electricity production providing an improvement over diesel generation, the total GHGs for hybrid systems remain high. When kerosene is considered neither the total cost nor the total emissions of hybrid systems is the lowest at any reliability threshold, which could lead policymakers with intentions to reduce cumulative costs or GHGs to incentivise either diesel or PV minigrids instead.

Commercial systems

The LCUEs and total GHGs for systems supplying commercial loads are shown in fig. 7.4 b); in contrast to domestic-only systems, I find that commercial off-grid systems powered by PV and storage are cheaper than hybrid systems at almost all blackout thresholds. This is a result of two factors, the first of which being that greater daytime demand matches the generation profile of PV better than for domestic demand only, increasing the proportion of power that is used directly by the community.

Secondly, this is a result of the timescales over which the system is optimised. When considering a relatively short timeframe of only a few years, the least-cost option for a hybrid system is to invest in low capital expenditure diesel generation to meet high capacity loads on

demand. This locks the system in to a diesel-dominated route: over short time horizons, once the initial investment in diesel has been made, at no point is it cheaper to step backwards and invest heavily in PV and storage instead of greater diesel capacity. The evolution of the size of hybrid systems is relatively independent of the reliability: the capacity of PV, storage and diesel generation grows modestly throughout the system lifetime, but the diesel generator is used more frequently when higher reliabilities are required.

I calculate that PV systems remain the least effective option in mitigating kerosene usage but, considering the total GHG emissions, they outperform both other generation options. For a blackout percentage of 5% the total GHGs when using PV systems is less than half those of either diesel or hybrid systems, demonstrating a clear advantage, although as the systems become less reliable the GHGs from kerosene have an increasingly large impact.

As commercial loads supply far more power than their domestic counterparts the systems can benefit from economies of scale: the distribution network, for example, does not need to be made proportionately larger for greater loads as it is more dependent on the density of the community. This is one of the contributing factors to the LCUE of commercial systems being lower than those supplying domestic loads only and this effect was also shown in section 3.3.1. I also find that commercial systems had lower emissions intensities than domestic systems however, as the demand is much greater, the total GHGs are also larger.

Discussion of off-grid systems for domestic and commercial energy access

The low initial costs and high levels of operational experience of diesel generators have made them a common choice for power supply in rural India. When considering their preferential displacement of kerosene during operation, diesel generation for domestic energy access is the most effective at mitigating emissions when more than blackout periods of 25% or more are acceptable. I have also found, however, that the LCUEs of diesel generation for domestic systems make it the most costly option other than for the most reliable systems.

Diesel minigrids are simple and effective at supplying electricity on demand but if the goal is to provide affordable and clean power reliably throughout the day then another option must be considered.

PV and storage off-grid minigrids can supply domestic power at a lower cost, and with lower GHGs, than diesel but there are two main disadvantages. Firstly, to meet the very highest levels of load satisfaction requires an increasingly large initial capital investment, relatively oversizing the system and reducing its overall cost-effectiveness to achieve the aim of meeting smallest final fractions of demand. Secondly, energy shortfall periods generally occur at the same times as demand for lighting and so their ability to mitigate kerosene usage, and the associated GHGs, is reduced.

My results suggest that hybrid minigrids should be the preferred option for system operators in providing domestic energy access. Their low LCUEs can provide the lowest tariffs and the resilience of the system offered by having both PV and diesel generation provides the guarantee of at least some power being supplied even if one source goes offline. Hybrid systems emit more GHGs than PV systems but less than those supplied by diesel, and retain the ability of the latter to be effective at kerosene mitigation.

When considering commercial energy access, the higher initial investments in PV and storage pay off in the long term in more ways than one. In addition to providing the lowest LCUE, these systems also yield the lowest total GHGs both with and without kerosene usage being considered. At all but the highest fractions of demand they consistently outperform hybrid systems, which in turn outperform diesel-only systems, in terms of LCUE.

PV and storage are the wisest option to invest in at the start of the project in the commercial case and, once deployed, result in further deployment that ultimately results in a lower LCUE. When PV generation is as option in a hybrid system, rather than a necessity in a PV-only system, the optimisation process selects some PV and storage but become locked-in to diesel generation to reduce this investment. As diesel generation has a lower capital

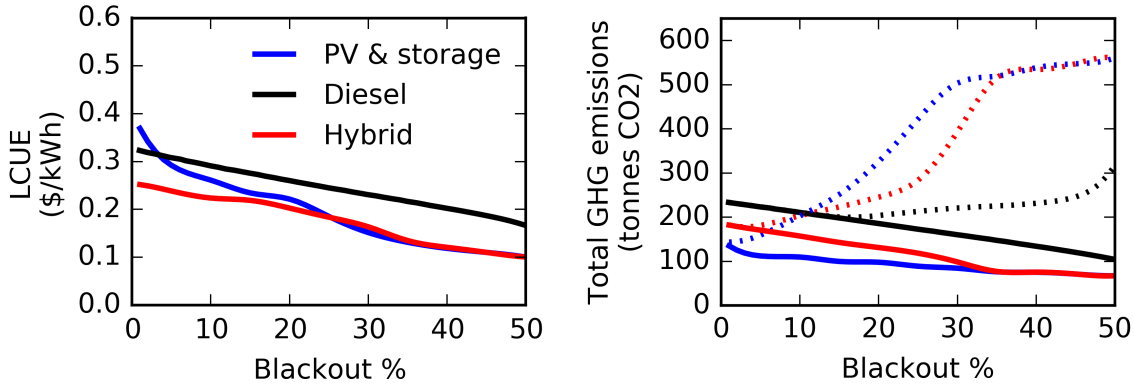
investment it can provide a lower LCUE in the short term, and is therefore selected by the optimisation process, even though in the LCUE is higher in the long term. This optimisation selection can be explained by the nature of the modelling framework but also reflects the reality of minigrid operators being unable or unwilling to invest in a new generation system, in this case PV and storage, that will pay off only in the long term. Being locked in to diesel generation means that the cost of power is higher than necessary and that the GHGs emissions are far greater. If this issue can be overcome then off-grid PV minigrids could become the preferred option and provide a substantial benefit in providing power for commercial loads.

7.3.3 On-grid minigrids

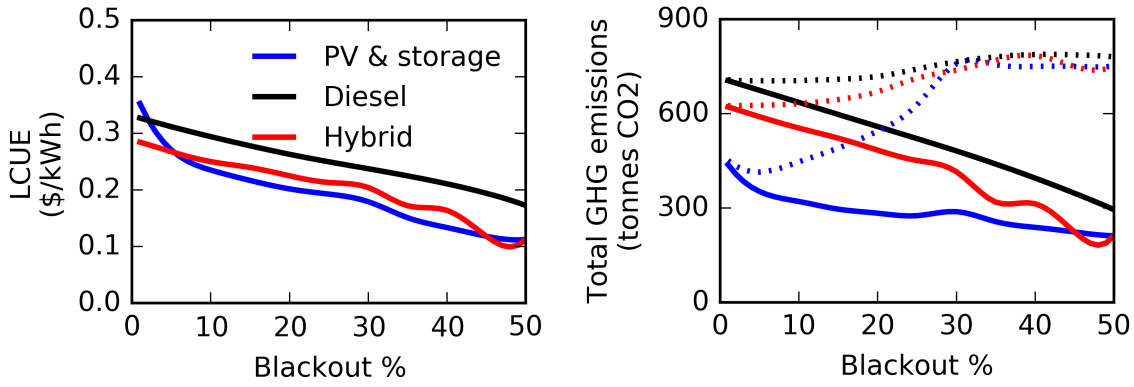
Domestic systems

The impacts from domestic on-grid systems without grid charging are shown in fig. 7.5 a). The availability of grid power has a normalising effect on the system impacts as the supply from the grid reduces the size of the minigrid necessary to reach a given blackout percentage in comparison to the off-grid case. At blackout percentages of less than or equal to 30% the minigrid supplies power for the majority of time, albeit with grid electricity used preferentially when available, and as the system reliability increases the results tend towards those of the off-grid case.

In all cases the LCUE is significantly reduced by the addition of cheap grid electricity and, as in the off-grid case, PV systems feature a sharp increase in LCUE at the lowest blackout percentages. I find that at blackout percentage of greater than 5% PV systems are cheaper than diesel generation but, as before, more costly than hybrids. In the regime of blackout percentages greater than 35% the optimum hybrid system is the same as the optimum PV system: this is because the availability of grid electricity, backed up by small amounts of PV and storage, is adequate at meeting the threshold blackout criteria without the need for a backup diesel generator.



(a) Impacts of on-grid minigrids for domestic electricity access.



(b) Impact of on-grid minigrids for commercial electricity access.

Fig. 7.5 The LCUEs and GHGs (solid lines) of a) domestic and b) commercial on-grid systems supplied by PV & storage (blue), diesel generators (black) or a hybrid (red) and the additional impact of kerosene lamps (dotted lines).

PV and storage also provide power with the lowest GHGs emissions for on-grid systems. When I consider the additional kerosene emissions the PV systems have the lowest total emissions for blackout percentages of 11% and below only, again as a result of being less effective at supplying power when lighting is needed. Above this threshold I calculate that diesel systems are more effective at mitigating kerosene usage, and hybrid systems to a lesser extent, and have total emissions around half of those resulting from the use of PV systems.

Commercial systems

The LCUE and GHGs associated with on-grid systems are shown in fig. 7.5 b). Once again the integration of grid electricity reduces the overall system LCUE significantly and, as for off-grid commercial systems, I calculate that PV and storage offers a lower LCUE in the long term, other than for the highest reliability systems. I find that hybrid systems provide the lowest LCUE at very low blackout percentages and the cost of electricity of diesel is the highest at almost all levels of demand satisfaction.

In contrast to domestic on-grid systems, I find that PV minigrids satisfying commercial demands have the lowest GHGs both with and without kerosene usage being considered. For high-reliability systems with blackout percentages of 10% or less the total emissions from PV systems are 25% lower than their closest competitors, hybrid systems, and at low reliabilities the total GHGs are approximately equal, albeit with diesel systems maintaining the highest emissions intensities.

Systems with grid charging

Centralising battery storage in a local minigrid system could present economies of scale in comparison to individual ownership at the household scale and, if systems with a grid connection are permitted to store power from the grid in batteries rather than local generation alone, this would have an effect on system design.

When considering systems with the lowest LCUEs I find that grid electricity, backed up by batteries, is able to supply baseload power and is reliable enough to maintain the storage backup to avoid blackout periods in all but the highest-reliability systems. For domestic systems, as the cost of grid electricity is so low, investments in PV are too costly to be considered for installation and diesel generation is used only for small fractions of the time and systems with grid charging have LCUEs of around half those without. For commercial systems with grid charging a small amount of PV is chosen to be installed and provides a moderate amount of energy for systems with blackout percentages in the range 10–40%. For systems less reliable than this the grid alone is sufficient in meeting demand, and for more reliable systems diesel generation displaces the use of PV. The effects that grid charging systems have on GHG emissions is explored in more detail in section 7.4.4.

Discussions of on-grid systems for domestic and commercial energy access

I have found that a connection to the national grid network has a normalising effect on the impacts of the minigrid. In comparison to off-grid systems, the LCUEs are reduced as an effect of the integration of cheap grid power, whilst the GHG emissions from power generation are shown to increase for PV and hybrid systems but decrease for those using diesel generation.

For on-grid domestic systems, hybrid generation again supplies power at the lowest LCUE whilst PV systems offer the lowest total GHGs for systems with low blackout percentages. The threshold for PV systems changes, however, and on-grid PV systems must have a blackout percentage of 11% or less to have the lowest GHGs, rather than 20% for off-grid systems. For commercial systems, I observe again that early investment in PV and storage systems returns significant LCUE savings in the long term and are the most cost-effective systems. Furthermore, they can result in around 25% lower GHG emissions after kerosene is accounted for in comparison to hybrid systems for blackout thresholds of 10% and below.

On-grid systems in which grid storage is permitted can provide lower LCUEs than those without and rely very little on local generation sources. PV is used only modestly in commercial systems and is replaced by diesel to achieve the lowest blackout percentages, with diesel generators also being used in domestic systems.

7.4 Impacts of deploying minigrids

7.4.1 Introduction

In this section I consider the impact of using off-grid systems in comparison to two cases of incumbent energy technologies. First, I investigate providing domestic electricity access and its benefits in comparison to a counterfactual case where the community relies on kerosene lamps for lighting. In the second case study, I evaluate the effects of providing off-grid systems for commercial electricity access and compare this with using incumbent diesel generation to provide the same levels of service.

I assess the impact in terms of the average expenditure and GHG emissions per capita per year of the system lifetime. This helps us to understand the effects of the system at the individual level and will allow a comparison to other interventions. I also present the reductions in total expenditure and GHGs as a percentage decrease in comparison to the counterfactual cases. The results are shown in figs. 7.6 and 7.7 with expenditure per capita on kerosene (dashed lines) also displayed.

For domestic kerosene reduction I do not account for the benefits of the additional services that are provided for as part of the electricity provision. In terms of my analysis, these benefits are considered as a bonus of electrification rather than used as a performance indicator. For commercial diesel reduction I assume that the minigrid systems are using modern, efficient devices rather than incumbent inefficient devices, hence allowing a comparison between

present and future diesel usage. I assume that the electricity services provided in the commercial cases are otherwise identical.

7.4.2 Domestic kerosene reduction

The impacts and benefits of off-grid systems providing domestic energy access are shown in fig. 7.6. As shown before at the system level, diesel generation results in the highest cost of electricity but here one can see explicitly how it provides the greatest kerosene mitigation as expenditure on kerosene is present for systems with blackout percentages of 20% or higher. PV systems are least effective at mitigating incumbent lamps and result in continued dependence on buying kerosene. When I consider the electricity tariffs and kerosene expenditure combined, hybrid systems with 1–20% blackouts can provide expenditure savings of up to 50% for rural communities compared to incumbent energy usage.

PV and storage systems can provide the greatest GHG savings for systems with blackout percentages of less than 20%, peaking at a reduction of up to 85% compared to kerosene lamps and emitting less that 10 $kgCO_{2eq}$ per capita per year for electricity services. Above this threshold, diesel generation provides the greatest aggregated GHG savings as its kerosene mitigation potential outweighs its high emissions from power generation.

All of the electrification options provide savings relative to kerosene usage both in terms of cost and GHGs. I calculate that PV systems provide the greatest GHG reduction but this comes at a price premium and is reliant on achieving low blackout percentages to mitigate kerosene. Hybrid systems, however, offer greater expenditure savings both for electricity services and kerosene usage, whilst also significantly reducing GHGs.

7.4.3 Commercial diesel reduction

The impacts of using off-grid minigrids for commercial energy access in comparison to incumbent diesel generation are shown in fig. 7.7. I find that, analogous to fig. 7.4 b), PV and

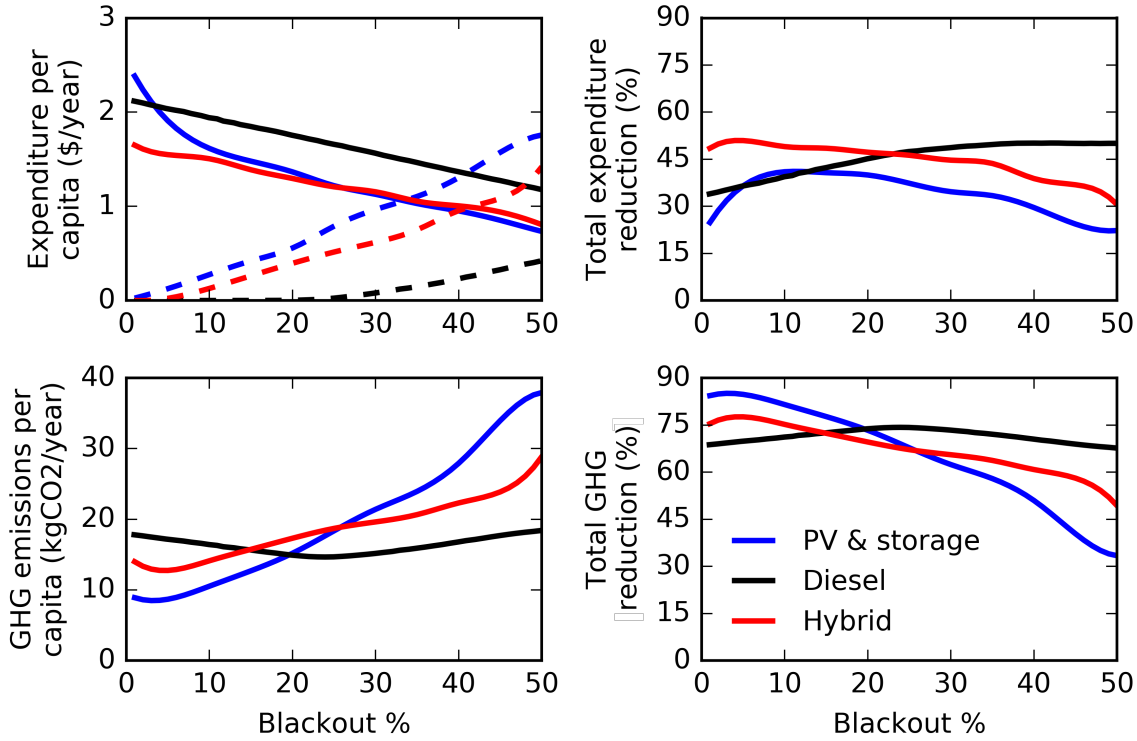


Fig. 7.6 The impact of domestic energy access in displacing kerosene usage via off-grid minigrids (solid lines) supplied by PV & storage (blue), diesel generators (black) or a hybrid (red), and the additional impact of expenditure on kerosene lamps as a backup (dashed lines).

storage systems offer the greatest expenditure savings on average by providing the lowest LCUE option. Furthermore, despite not mitigating all of the expenditure on kerosene at blackout percentages of 5–20%, I calculate that the total reduction in expenditure is more than 60% in this range compared to incumbent diesel. Hybrid systems can reduce expenditure by around 55% whilst using efficient devices in minigrid systems can reduce the cost of diesel generation by around half.

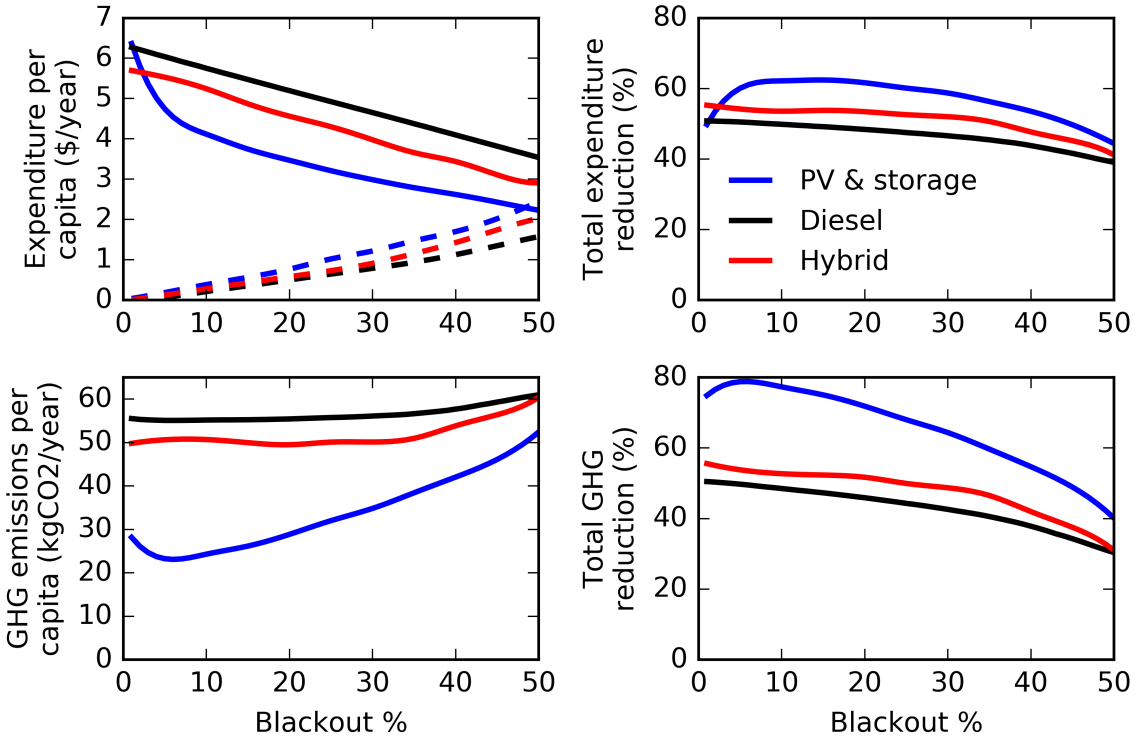


Fig. 7.7 The impact supplying commercial loads compared to using incumbent diesel generation via off-grid minigrids (solid lines) supplied by PV & storage (blue), diesel generators (black) or a hybrid (red), and the additional impact of expenditure on kerosene lamps (dashed lines).

The increased electricity usage for commercial purposes leads to greater annual per capita GHG emissions compared to domestic usage only, but also present an opportunity for significant GHG mitigation relative to incumbent diesel generation. I find that systems supplied by PV and storage can provide a maximum reduction of 80% for GHGs whilst hybrid and diesel systems can offer up to 56% and 50% reductions respectively, the latter

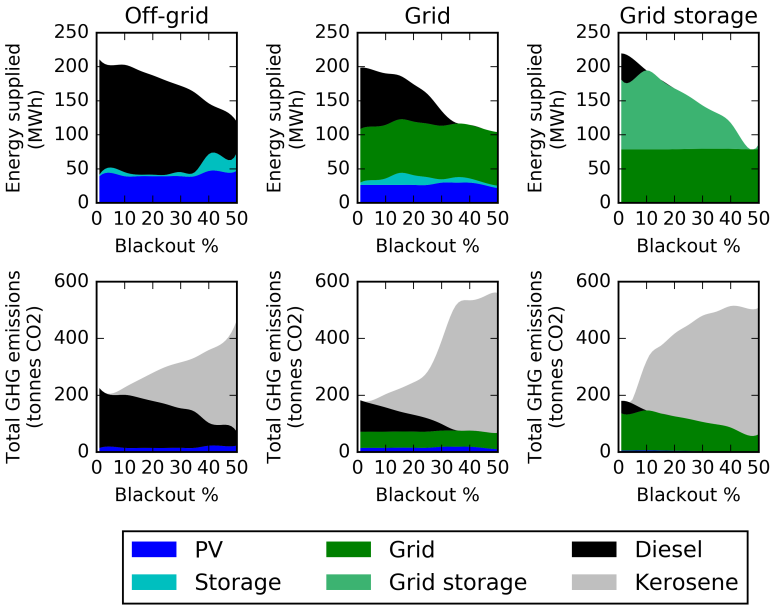
being a direct consequence of using more efficient devices. Critically, I find that PV and storage systems can simultaneously deliver expenditure savings of more than 60% and GHG reductions of more than 75% for systems with 5–10% blackouts: this is an important step in providing reliable, affordable and sustainable power.

7.4.4 Hybrid system energy mix

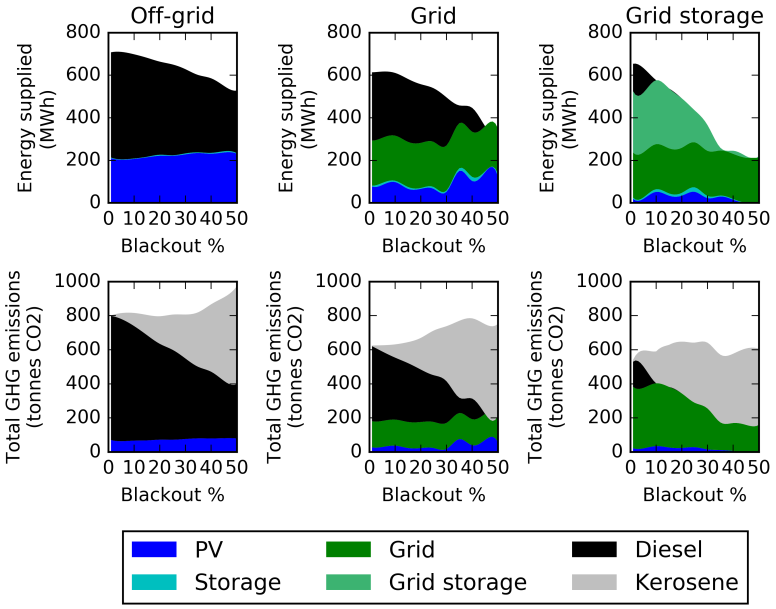
Hybrid energy systems select the cost-optimal configuration of energy sources but, as we have seen, this does not always present the most long-term benefit: for domestic off- and on-grid systems I found hybrid generation to provide the lowest LCUEs but this was not the case for commercial systems. Furthermore, their emissions were higher than PV systems and more difficult to characterise, as was their energy mix, owing to the variety of generation sources. For this reason I further investigate hybrid systems in more detail. In fig. 7.8 I show the total energy supplied and total GHG emissions over the lifetime of the system for a) domestic and b) commercial energy access for off-grid systems and those with and without grid charging.

Domestic energy access

As shown in fig. 7.8 a), in the off-grid and grid-connected cases I find that a baseload of PV power is supplied at all blackout percentages which reflects the benefit of PV in meeting daytime demand. This is augmented by grid electricity: in the daytime this reduces the total amount of PV required, and at night this offsets the need for some diesel generation. Battery storage plays a modest role in both of these scenarios by supplying small amounts of evening power before diesel generation is dispatched to meet the higher levels of demand satisfaction. Greater supply of diesel generation is the most effective means of supplying additional power at lower blackout percentages. For grid-storage domestic systems, however, grid power is used exclusively at all but the lowest blackout percentages owing to its low cost.



(a) The energy mix (top) and total GHG emissions (bottom) of hybrid systems for domestic energy access.



(b) The energy mix (top) and total GHG emissions (bottom) of hybrid systems for commercial energy access.

Fig. 7.8 The energy mixes and cumulative GHG emissions of hybrid systems without the grid, with the grid, and with grid storage for a) domestic and b) commercial energy access, with additional GHGs from kerosene also shown.

The GHGs associated with electricity generation, not yet considering kerosene, are broadly similar for each system type with off-grid systems having marginally greater emissions owing to their higher reliance on diesel generators. The use of diesel generators, however, is critical in mitigating emissions from kerosene, as I can see that for all systems the GHGs from kerosene are greater when those from diesel are lower. This is particularly evident for grid-storage systems: the reliability profile of the grid has the effect of concentrating blackout periods into the times of the day during and a few hours after grid supply is lowest, typically when in the evening when lighting demand is highest. If several hours have passed without grid supply and the batteries are exhausted then the system will be unable to supply power, resulting in high kerosene usage and hence high GHG emissions.

Commercial energy access

The total energy supplied and total GHGs emitted over the lifetime of the commercial systems are shown in fig. 7.8 b). I find that PV features in all system types owing to the improved matching of the times of generation and commercial demand; this is greatest for off-grid systems where between 30–45% of energy is supplied by PV and negligible amounts of power are supplied by battery storage as PV meets demand directly during the daytime whilst diesel generators are used during times of low irradiance or at night. On-grid systems, both with and without grid storage, also feature PV which provides power during the daytime at times when the grid is unavailable and when commercial activities are high. Diesel generation is relied upon significantly in off-grid systems but its usage is mitigated, although not entirely, by grid power.

As grid-storage systems are less reliant on diesel generation I find that they emit lower GHGs from electricity generation that on-grid systems without grid storage and also less than off-grid systems, despite using the least amount of PV. When kerosene usage is considered the total GHG emissions is relatively independent of the blackout percentage: any reduction in

diesel generation is met by an increase in kerosene usage, as many of the high-demand periods which are preferentially met by diesel are now during the daytime owing to commercial activities, rather than at night as was true in the domestic case. My results suggest that using grid power to offset diesel generation, for example by switching from off-grid hybrid systems to grid-storage hybrid systems, results in a decrease in total GHGs of 25–30% for systems with blackout percentages in the range 1–10%.

7.4.5 Discussion of the impacts of deploying minigrids

I have observed in this section that displacing incumbent energy sources can significantly reduce the expenditure and GHG emissions of rural communities. Off-grid systems of all kinds can effectively mitigate kerosene usage if they are suitably reliable and hybrid systems in particular can provide expenditure reductions of around 50% whilst also reducing GHGs by more than 75%. PV and storage systems are less effective at reducing expenditure but would nevertheless provide a significant financial benefit to rural communities whilst also offering lower GHG emissions.

Displacing incumbent diesel generation would also allow financial and environmental savings. Here I have shown that investments in PV and storage systems pay off in the long term with the lowest LCUEs and also provide the highest GHG savings. Both hybrid systems and diesel systems using efficient devices can also yield cost and GHG reductions compared to diesel systems already deployed.

We have seen before that PV and storage minigrids are most expensive at low blackout percentages as they must be comparatively oversized to achieve the highest levels of service. From the analysis in this section, however, when compared to incumbent kerosene and diesel usage I find that the greatest expenditure and GHG savings occur in the region of 5–10% blackouts. In this region the reliability of electricity is sufficient to offset the usage of

kerosene, in particular, and to provide a net cost benefit to the users despite a relatively high electricity tariff.

Hybrid electricity systems are designed with short-term cost optimisation in mind; whilst they provide the lowest LCUE for on- and off-grid domestic energy access, they are outperformed by PV systems for commercial access and, in the case of grid storage, systems are dominated by grid power and diesel generation with only small amounts of PV. Despite their high emissions I find that diesel generators are critical in hybrid systems for mitigating GHGs from kerosene since, at present, grid electricity alone is inadequate. On-grid hybrid systems for domestic access, for example, exhibit a sharp rise in kerosene GHGs for blackout percentages of 25% or higher which correlates with the decreasing use of diesel generators.

Grid-storage minigrids provide power with the lowest LCUEs but are also the most vulnerable. I have found that domestic systems with blackout percentages of more than 10% rely entirely on grid power and battery storage, whilst commercial systems also incorporate small amounts of PV generation. This is reliant on the supply of grid power: if the grid is unavailable for several hours and the batteries are depleted, which is most likely to happen during the evening, grid-storage systems may be ineffective in mitigating kerosene emissions which we observe in particular in fig. 7.8 a). This is an effect of the statistical modelling of the grid profile which is not the same as for the other technologies and, since the latter are considered to be not subject to probabilistic failures in performance, one should take appropriate caution in interpreting this effect. Furthermore, the kerosene mitigation potential and system reliability of grid-storage systems will be dependent on the performance of the batteries; fast-discharging batteries, for example, will supply larger amounts of power if demanded but will be depleted earlier and result in longer blackout periods.

The results I present here suggest that the performance of battery technology will have an impact on the viability of grid-storage systems and, in particular, their resilience to periods when the grid is not available. I found that including diesel generation for grid-charging

systems is cost optimal for blackout thresholds of 10% or less and mitigates the risk of shortfalls caused by the batteries, and therefore additional GHGs from kerosene usage. Including diesel generation as a fallback option in systems with higher blackout percentages, however, would come at a price premium.

7.5 Effect of grid expansion

7.5.1 Introduction

Off-grid PV systems and on-grid hybrid systems could be considered as ideological opposite electrification strategies. Assuming they are suitably reliable, off-grid PV minigrids provide electricity with low GHG emissions and higher initial investments are returned as lower long-term LCUEs, particularly for commercial systems. Hybrid on-grid systems, however, are cost-optimal in the short term but not necessarily over the lifetime of the system and are reliant on diesel generation and grid electricity, both of which have higher GHGs from power production. The comparison between these two strategies are considered in this section.

I inform the decision on whether a community should receive an off-grid or on-grid minigrid system by calculating the grid extension breakeven distance. I have calculated the breakeven distance at which off-grid PV systems become cheaper than on-grid hybrid systems in terms of their total cost, including kerosene expenditure, and in two scenarios, one where grid charging is not permitted and one where it is. Systems with the same blackout threshold are compared but, owing to the differences in system composition, blackouts may occur at different times of the day or year.

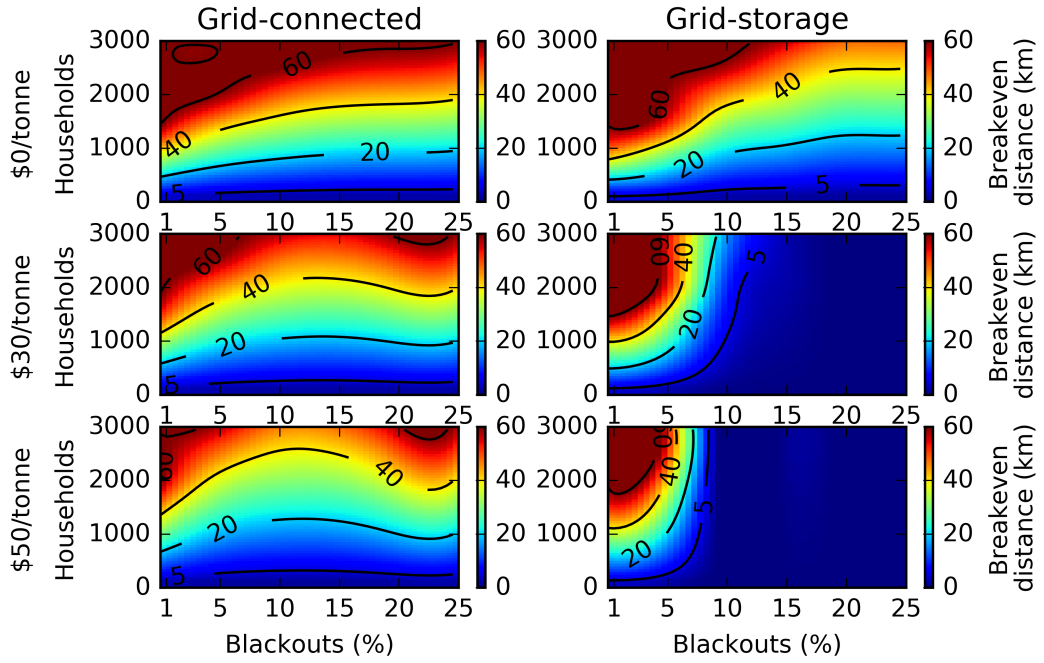
In larger communities the costs of grid extension are relatively cheaper, as the expense is shared amongst a larger number of households and a greater amount of electricity usage; for this reason I consider a range of community sizes to identify any differences in electrification strategies. The number of households does not necessarily need to be in one contiguous

community but should be nearby in comparison to the required extension distance; for example, two villages of 500 households each which are 1 km apart but 15 km from the nearest grid infrastructure could be considered as a single community of 1000 households requiring a total grid extension of 16 km. This assumes the agent aims to electrify all of the communities in a region via branches from an existing grid and not necessarily via a topologically and topographically optimised network, which would require a mathematical modelling process beyond the scope of this analysis.

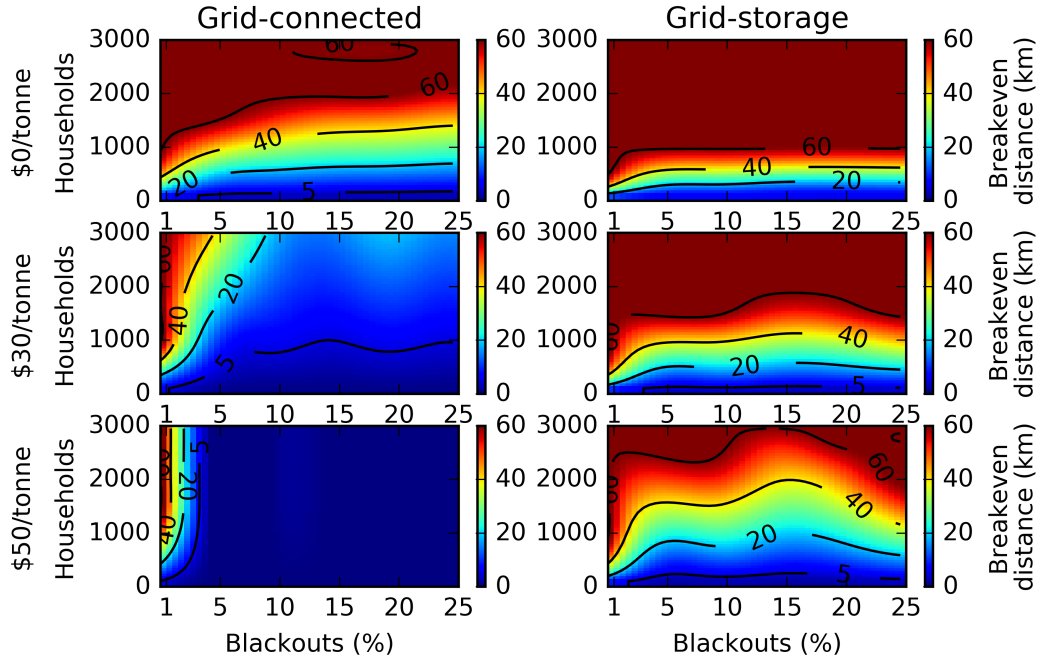
To incorporate the environmental impacts of the systems I include carbon prices which could be introduced either directly or indirectly as the result of, for example, reducing subsidies on kerosene or fossil fuel generation. In addition to the current situation of no carbon price, I also show the results of a price of \$30/tCO_{2eq} and \$50/tCO_{2eq} as potential future scenarios [110] to demonstrate their impact. All GHGs are considered, including those from kerosene emissions, to fully capture their effect. Finally, as the aim of the study is to provide reliable power to rural communities, I consider systems with blackout percentages in the range 1–25%, rather than 1–50% as before. The results of this analysis are shown in fig. 7.9.

7.5.2 Breakeven distances for domestic systems

The breakeven distance for off-grid PV systems to be more cost-effective than on-grid hybrid systems is shown in fig. 7.9 a). In the grid-connected case, without grid storage, I find that the breakeven distance is dictated mainly by the community size: for larger communities, the grid extension cost is shared between a greater number of households and decreases relative to the total cost. Introducing a carbon price has a moderate effect on systems with 5–10% reliability as off-grid PV systems have lower GHG emissions than on-grid hybrid systems, but off-grid systems are preferable mainly for smaller remote communities, for example villages of 500 households which are more than 10 km from the grid.



(a) Breakeven distances for domestic energy access.



(b) Breakeven distances for commercial energy access.

Fig. 7.9 The breakeven distances off-grid PV minigrids for a) domestic and b) commercial energy access at various carbon prices. Adapted from Sandwell et al. [225].

In the case of grid charging systems, when no carbon price is considered and at low blackout percentages, I find that the breakeven distances are comparatively high owing to systems supplied by cheap grid power and diesel generation outperforming relatively oversized PV systems. When a carbon price is considered the breakeven distance changes from being dependent mainly on community size to being governed by the blackout percentage. As I have shown in fig. 7.8 a), grid-storage hybrid systems for domestic access emit very large amounts of GHG emissions for blackout percentages of 10% and higher which the carbon price penalises. This has the effect of incentivising off-grid PV systems ahead of grid connections to the extent that, for blackout percentages of more than 10–15%, it is more cost effective to deliver off-grid systems to communities of almost any size even if they are adjacent to existing grid infrastructure.

7.5.3 Breakeven distances for commercial systems

The introduction of commercial energy access has a significant effect on the breakeven distance, shown in fig. 7.9 b). Firstly, comparing off-grid PV systems to hybrid systems without grid charging and with no carbon price, the breakeven distances decrease in comparison to domestic systems as a result of the relative reduction in extension costs caused by the increase in total electricity usage. When I introduce carbon prices, however, the breakeven distance switches its dependence from mainly community size to overwhelmingly blackout percentage. At a carbon price of \$30/tCO_{2eq} even large communities of 1000 households or more have breakeven distances of less than 20 km, and at a carbon price of \$50/tCO_{2eq} any community is more effectively provided with electricity via an off-grid PV system for all but the lowest blackout percentages. This is because, in the range I consider here, total lifetime GHG emissions from off-grid PV systems are around 25% lower than those for on-grid hybrids and the carbon price impacts the former far less than the latter.

Although commercial grid-storage hybrid systems also emit significant GHGs over their lifetimes, shown in fig. 7.8 b), their cost of electricity is lower as a result of drawing more power from the grid. Their low cost of electricity means that, when no carbon price is considered, I find that the breakeven distance is highly dependent on system reliability and all but the smallest communities of a few hundred households or less would best receive electrification via grid-storage hybrid systems. The prohibitively high breakeven distances are reduced, however, when I introduce a carbon price. For communities of 1000 households, for example, off-grid PV systems are more competitive at distances of around 30 km or more from the grid at a price of \$50/tCO_{2eq}, whereas with no carbon price this distance was more than 60 km. Nevertheless, at present the low cost of grid-storage systems for commercial energy access outweighs the environmental benefit of off-grid PV systems and, if grid charging were permitted, only the most remote communities would be suitable for off-grid PV.

7.5.4 Recommendations

The most cost-effective method of providing power to a rural community depends its size, the reliability requirements, its distance from existing infrastructure, whether grid charging of storage is permitted, and the presence and magnitude of a price of carbon. The decision to extend the grid or not will depend on each community under consideration, but using my results I can infer the conditions under which off-grid PV systems would be favourable.

As expected, smaller and more remote communities provide better candidates for off-grid PV systems than those larger and closer to the grid. When no carbon price is considered then the breakeven distance in all scenarios, both with and without charging and for domestic and commercial access, is dependent predominantly on community size. When all costs are considered, including those from kerosene usage that has not been mitigated, commercial

on-grid hybrid systems with grid storage display the greatest breakeven distances owing to their low cost of electricity.

I observe two effects when introducing carbon prices in my analysis. When comparing off-grid PV to hybrid systems without grid storage for domestic access, and also to hybrid systems with grid storage for commercial access, the breakeven distances decrease but remain governed mainly by community size. For the domestic case this is caused by both options having relatively similar GHG emissions, and for the commercial case with grid storage it is a result of the very low cost of grid electricity. When comparing to systems with grid storage for domestic access and systems without for commercial access, however, incorporating a carbon price has the effect of making breakeven distances governed more by the blackout percentage achieved. This is a result of both of these on-grid systems having significantly higher GHGs which, other than at the lowest blackout percentages, are not offset by the low cost of power.

From these results I suggest that off-grid PV systems should be designed to achieve between 5–10% blackouts. Systems in this range would have marginally lower breakeven distances with no carbon price, but would provide long-term benefits if one were introduced during their operational lifetime and, furthermore, have significantly lower GHGs than on-grid hybrid systems. For larger communities a grid-connected system will likely be cheaper if a high reliability is required, but the introduction of a carbon price could be used to make off-grid PV systems the cheaper long-term option for communities even if they are close to existing grid infrastructure.

7.6 Conclusions

7.6.1 Summary of results

In this chapter I have demonstrated the application of the CLOVER model and evaluated the effectiveness of minigrid systems in many scenarios. For off-grid minigrids I found that PV minigrids can satisfy domestic demands at a lower cost and GHGs than diesel generation, but only the systems with the lowest blackout percentages were able to effectively mitigate kerosene usage. Hybrid minigrids, however, were more effective and provided electricity with lower LCUEs. For commercial access, however, investments in off-grid PV minigrids yielded the lowest lifetime LCUE and lowest emissions owed in part to better demand matching. Being locked-in to diesel, either solely or as part of a hybrid system, provides lower LCUEs in the short-term but greater expense over the lifetime of the system.

A connection to the national grid network had a normalising effect on the minigrid systems: low-cost grid power reduced the average LCUE but increased the total GHG emissions. Once again the lowest LCUEs are available to hybrid systems for domestic generation and PV systems for commercial generation. Systems with grid storage have the lowest LCUEs as they maximise the usage of grid power, however their reliance on an inherently unpredictable power supply makes them the most vulnerable to grid outages. Considering grid-storage hybrid systems, the kerosene mitigation potential is dependent on the performance of the battery storage and the presence of a diesel generator and the system is vulnerable to blackouts if one of these were to become unavailable.

I have found that off-grid PV systems for domestic energy access can provide up to 85% reductions in GHG emissions from kerosene lamps, reducing per capita emissions from electricity access to just 10 $kgCO_{2eq}$ per year. Hybrid systems provide the greatest expenditure reductions with a slightly lower reduction in GHGs, and all generations options provide both cost and GHG savings compared to kerosene lamps. For commercial energy

access, PV systems can reduce expenditure by more that 60% compared to incumbent diesel generation and reduce GHGs by up to 80%. Off-grid PV systems outperform the other generation options, both in terms of cost and GHG emissions, in supplying commercial loads.

I investigated the grid extension breakeven distance for two electrification options: off-grid PV minigrids and on-grid hybrid systems, both with and without grid charging. The smallest and most remote communities would be the best candidates for off-grid PV systems, however when a carbon price equivalent is introduced the dependence of breakeven distance on community size changes. For domestic on-grid hybrid systems with grid storage and commercial on-grid hybrid systems without grid storage, the carbon price introduces a dependence on blackout percentage rather than community size: in these cases, mitigating GHGs via off-grid PV systems would be particularly beneficial. The most effective long-term electrification solution will depend significantly on the community size, supply reliability requirements and the ways in which on-grid systems will be permitted to interact with the national network, however this analysis shows that many of these conditions favour the deployment of off-grid PV systems for energy access even when existing grid infrastructure is nearby. This highlights the effect of considering externalities, such as kerosene mitigation and GHGs, in the long-term planning of electrification options.

7.6.2 The GHG mitigation potential of PV

The results of this chapter suggest a significant potential for PV technologies to mitigate GHG emissions. In domestic settings off-grid PV systems are not the cheapest option but can still provide cost savings compared to incumbent kerosene usage whilst reducing total GHG emissions by up to 85%. For commercial off-grid systems, long-term investments in PV generation result in systems that provide both the cheapest and lowest-emissions electricity for productive uses and can also expand in capacity to facilitate economic growth. When considering the impact of grid electricity I found that off-grid PV minigrids can achieve

similar or lower costs than grid-connected hybrid systems, even nearby to an existing grid, under the certain conditions: these could be achieved with the introduction of a carbon price or an equivalent subsidy towards promoting renewable energy, which are already being proposed.

In order for PV to realise its potential it will still need to overcome several challenges. Grid-connected systems that are permitted to store power from the network can achieve very low costs of electricity and typically do not include considerable amounts of PV generation; these are, however, likely to be more vulnerable to outages. The most cost-effective PV systems, those which facilitate commercial energy access, rely on the early deployment of PV and sufficient growth in productive daytime usage to improve demand matching. These system will therefore be reliant on communities developing their economies to grow local demand sufficiently and to provide a market for their power, despite them formerly lacking significant electricity access. The provision of electricity will provide one component of catalysing energy growth but many more, including favourable policies, successful business models, community engagement and economic development will also play important roles. PV has the opportunity to provide substantial reductions in GHG emissions but in order to do so it must also rely on other influencing factors.

Chapter 8

Conclusions

8.1 Introduction

Throughout this work I have aspired to gather and analyse evidence in order to assess the potential of PV in mitigating GHG emissions. This was done in two ways: to assess the potential for emerging PV technologies, and to assess the application of PV technology in the context of minigrids for rural electrification in India.

In chapters 1 and 2 I presented a review of the literature, the research gaps that I aimed to fill, and the frameworks and methodology that I used in doing so. In chapter 3 I assessed the performance of mature and emerging PV technologies in minigrid systems in rural India and compared them to incumbent fossil fuel generation. In chapter 4 I presented an LCA of a novel design of HCPV module and assessed its potential to mitigate GHGs from the grid network in several high-irradiance locations. In chapter 5 I analysed the results of fieldwork undertaken in rural communities in Uttar Pradesh, India, to provide a baseline for my later energy systems modelling and to gather primary data on the requirements and usage of electricity services in rural households. In chapter 6 I presented a novel model for simulating, optimising and assessing minigrids for rural electrification and I applied it in chapter 7, where I used several assessment methods to compare the costs and GHGs associated with PV minigrids in comparison to other electrification options.

In this final chapter I will combine the key results to assess the overall potential of PV technologies to mitigate GHG emissions, particularly in the context of rural electrification in Uttar Pradesh, and identify areas for future work.

8.2 Key results of the research

8.2.1 Emerging PV technologies

Organic photovoltaics

In chapter 3 I found that manufacturing innovations in OPV technology could lead to it becoming competitive with more mature PV technologies in minigrid systems in India. If these innovations are transferred to the commercial scale, OPV could supply electricity to rural communities at an LCUE similar to, or lower than, those of c-Si and CdTe. Combined with the low GHG emissions expected from the future OPV manufacturing process, the specific emissions of the electricity could be similarly low. When I compared future OPV to diesel generation supplying the same community demand, I found that the former could mitigate GHG emissions with a MAC of only \$16/tCO_{2eq}, less than half that of mature technologies.

The potential for OPV to mitigate GHG emissions in practice will depend on how the technology develops. OPV has been successfully deployed at large scales and in the context of rural electrification [126, 127] but module degradation, leading to short lifetimes, may make the technology incompatible with the challenging environments often found in remote regions of developing countries. The greater robustness of, for example, c-Si PV means that minigrid developers have little incentive to risk a relatively unproven technology which would be a critical component their system. Furthermore the projected cost decreases for OPV modules are still yet to occur and, until these happen and the technology becomes commercialised, OPV is unlikely to used in this context. For these reasons mature PV technologies are more likely to be deployed, and are currently being deployed, ahead of OPV in the contexts I have explored and in others. Research continues to find methods of reducing the environmental impact of the technology and to increase its lifetime and so in the future,

when the technology has matured, it may play a greater role in GHG emissions mitigation in other scenarios [236, 237].

Concentrating photovoltaics

CPV was found to be far less effective in minigrid systems in rural India than other technologies. Greater systems costs, in particular caused by a greater requirement for battery storage, made the LCUE of CPV prohibitively high for rural electrification. The emissions intensity was found to be lower than for c-Si but the MAC in comparison to diesel was much greater, and unjustifiably high to be considered in the context of electricity access. I therefore chose to assess CPV in more favourable conditions where the advantages of the technology can be exploited.

My analysis of a new design of CPV module in chapter 4 provides an extension to the literature of CPV LCAs [16, 25–30]. I found that the reduced materials usage of the module also reduced the embedded energy and GHGs, performing favourably against other HCPV technologies, and that systems using the modules which are deployed in high-irradiance locations can provide EPBTs and CPBTs on the order of months, rather than years. Although this analysis presents only a small number of favourable potential deployment locations it suggests that the emissions intensity of energy generated and exported to the grid in those countries would be far lower than both the national network and other renewables technologies, providing a high potential for GHG mitigation in high DNI regions.

The decision to deploy of CPV technology, and therefore its potential to mitigate GHGs, may rest on its financial competitiveness in comparison to other options. Although my analysis suggests that HCPV can supply electricity at an LCOE lower than that of the SunShot target, this is dependent on the technology achieving an installed cost of \$1.00/W_p. This could come as a result of manufacturing improvements made possible by increasing global installed capacity but this is not currently the case. Annual installed capacity of CPV

systems peaked in 2012 at more than 120 MW but this figure had almost halved by 2014, and in 2016 less than 15 MW of CPV capacity was installed [5]. Compared with mature PV technologies, whose annual installed capacity in 2016 was three orders of magnitude greater than those for CPV [1], it may now be impossible for CPV to catch up and be deployed at large scales [238]. The introduction of carbon prices, or equivalents, could incentivise technologies like HCPV with very low emissions intensities but if the LCOE premium of HCPV compared to other renewables remains high then the latter would be wiser to install at the utility scale. If HCPV systems are deployed in favourable locations then they could significantly mitigate the GHGs of the local grid network, but at present it appears that more mature renewables technologies would likely be installed instead.

8.2.2 PV for rural electrification

Off-grid minigrids

In chapter 3 I demonstrated that mature PV technologies have several advantages over fossil fuel sources in providing power to several off-grid communities in India. Although in this chapter I found that the LCUE of all PV technologies was higher than that of diesel generation, the lower emissions of PV meant that mitigating GHGs from diesel was possible at a MAC of \$94/tCO_{2eq} for c-Si, or just \$34/tCO_{2eq} for CdTe. PV minigrids were also found to have much lower GHG emissions than the Indian national grid. My analysis of hybrid systems suggests that, at present technology and fuel prices, a transition is occurring between those mainly supplied by diesel generation to those mainly supplied by PV; this is accompanied by a halving of the GHG emissions of the system. My results suggest that introducing PV into existing systems, or deploying new hybrid systems dominated by PV generation, in similar communities in rural India could significantly reduce GHGs compared to either diesel-only systems or the grid.

In order to make my analysis more realistic, to be able to better capture a variety of potential scenarios and contexts, and to align it with the most important research areas [76], I developed a new modelling framework called CLOVER which is described in chapter 6. To make my analysis more robust to the case of rural electrification in northern India I collected and analysed data from rural households in Uttar Pradesh, described in chapter 5, which also provided more information on the sources of GHGs to be mitigated. Households without access to electricity were found to be heavily reliant on kerosene lamps for lighting which, in addition to being expensive and providing a poor quality of service, are responsible for GHG emissions of 381.1 $kgCO_{2eq}$ per household per year. Quantifying the mitigation of these emissions is not typically considered in minigrid simulations [58] and highlights an additional consideration for my analysis.

In chapter 7 I focused solely on the use of c-Si PV as it is the dominant technology both in the global PV market and for off-grid systems [5]. Using my analysis of energy access in rural communities in Uttar Pradesh I found that PV minigrids for commercial activities can supply power at both a lower LCUE and lower GHGs than either diesel or hybrid systems, both with and without accounting for kerosene mitigation; for domestic access, PV minigrids are still responsible for the lowest GHGs but hybrid systems are cheaper. PV minigrids are also effective at reducing total domestic expenditure on energy services and can reduce per capita GHGs by up to 85% in household settings. When compared to incumbent diesel generation for commercial systems, PV minigrids offer both the greatest savings and GHG mitigation potential of any system. Although these findings are specific to the case of villages in rural regions of Uttar Pradesh, the CLOVER model has the capability to be applied to other rural electrification scenarios elsewhere in India and around the world to explore the optimum minigrid systems in an analogous way.

These results are very positive for PV minigrids and show that, in this context, PV can provide affordable GHG mitigation as well as reliable energy. With recent subsidy schemes

in India, and in Uttar Pradesh in particular [54], favouring the deployment of PV minigrids it may be the case that diesel and hybrid systems become priced out of the rural electrification market, but this may also be a risk. Subsidies on initial capital expenditures may incentivise system oversizing, contrary to the methodology used in this work, which may increase costs and relative GHGs in the long term. If this were to happen, however, this would firstly result in greater kerosene mitigation as the oversized systems would likely be more reliable, and secondly would likely provide a satisfactorily reliable supply for longer, which would minimally affect system design in the long term. Minigrid developers could increase electricity use by providing the community with more devices, in particular productive loads, which would increase their energy sales [34, 47]. This would also mitigate any errors in load estimation which may have taken place at the minigrid design stage potentially owing to a scarcity of relevant data, a risk I aimed to reduce by undertaking primary fieldwork described in chapter 5.

Grid-connected systems

In chapter 7 I found the using a minigrid system in the same region of Uttar Pradesh to augment an unreliable grid connection and provide a superior level of service reduces the overall LCUE in comparison to off-grid systems, but increases the GHGs. The overall cost of electricity is far greater than the cost of grid power in India alone but one should not draw a false equivalency between these two scenarios: firstly, the level of service of the grid alone is insufficient in providing reliable electricity access, and secondly the GHGs from kerosene are greatly reduced when a minigrid system is also installed.

Systems which are permitted to charge battery storage from the grid network can reduce both blackout periods and costs, but they are potentially more vulnerable than those which are not permitted to do so: if several hours of consecutive blackouts occur then the system may be offline for long periods. Systems with grid storage also rely most heavily on centrally-

generated electricity from fossil fuel power plants, rather than local generation, and as a result will likely be locked in to GHG-intensive electricity in the long term. Furthermore, whilst greater integration with the grid is suggested as a likely future for rural minigrids both in India and globally [34], drawing larger amounts of electricity from the grid when power is available may exacerbate the issue of blackouts if utility-scale generation does not increase as much as demand. This could create ripple effects throughout the wider network and cause reductions in service elsewhere, ultimately further increasing GHG emissions from alternative sources of electricity such as diesel generators or from kerosene lamps.

I consider the grid extension breakeven distance, which was simple to find in chapter 3 as 19 km for mountainous terrain and 28 km for plains terrain, with more care in chapter 7. Incorporating several factors, I found that the lowest breakeven distances were typically available for systems designed for smaller community sizes with moderate reliability of supply, and that higher carbon prices could help further reduce them. The introduction of a carbon price also revealed that under certain circumstances the grid extension distance was negligible, meaning that off-grid systems were cost effective adjacent to existing infrastructure. A similar effect would likely be achieved with a subsidy for PV minigrids, which suggests that current policies may be in the process of realising the effect that minigrids can provide power at a lower cost, and lower GHG emissions, to communities nearby to the grid network.

8.3 Overall conclusions

8.3.1 An uncertain future for emerging techologies

Emerging PV technologies have a limited potential to mitigate GHG emissions and face several significant challenges. Overcoming the dominance of c-Si PV, or even capturing a market share from other mature technologies, is becoming increasingly difficult as their costs

continue to fall and so competing on the same terms may be outside of their ability. I have demonstrated this in the specific case of minigrids for energy access in India in chapter 3 where I found that, both at present and in the future scenario I modelled, neither OPV nor CPV provided a compelling economic alternative to mature PV. Whilst all technologies would be able to mitigate GHGs from grid electricity or diesel, this is dependent on their deployment and long-term viability and neither OPV nor CPV outperformed c-Si and CdTe PV. For this reason, I conclude that emerging PV technologies do not offer a potential to mitigate GHGs in the context of the rural electrification of villages in India.

Furthermore CPV is similarly limited in its potential to mitigate GHGs in utility-scale contexts. As I showed in chapter 4, whilst a new lightweight design of HCPV module can reduce the environmental impact of the electricity it produces, its deployment is dependent on its economic viability. The estimates of LCOE for the Fullsun systems even in the most favourable deployment locations are only marginally less than the LCOEs of established PV technologies and, given the rapid and continuing decline of PV costs, it is likely that Fullsun systems are now economically impossible to justify. I therefore conclude that the Fullsun HCPV systems will not be able to mitigate GHG emissions.

Both technologies may need to rely on niche applications for their future development. For OPV it may be possible to exploit its flexibility or aesthetics in fields such as building-integrated photovoltaics however other technologies, including more mature technologies, may inhibit growth in this area. For CPV this would be impossible and as a result it will need to rely on utility-scale installations in the most favourable locations in order to be deployed, in particular given the geographic and resource constraints which govern the effective use of the technology, and so other designs of HCPV systems are likely to continue to struggle against mature PV. For both technologies it may be the case that future interests in PV systems with extremely low GHG emissions will catalyse their deployment but, at present, it

is likely that systems will continue to use mature PV technologies. This limits the potential of OPV and CPV to actively mitigate GHG emissions.

8.3.2 A new paradigm for rural electrification in India

There is a significant potential for PV minigrids to mitigate GHG emissions via their deployment for rural electrification in Uttar Pradesh. My findings in chapters 3, 6 and 7 present considerable evidence in favour of using PV minigrids both to mitigate existing GHG emissions from kerosene lamps and instead of other incumbent electricity sources such as diesel generation and grid extension. This is underpinned by my findings that, in the rural communities of Uttar Pradesh that I consider, the costs of energy services from PV minigrids are lower than current expenditures on kerosene and that PV generation can supply power at a lower LCUE than either diesel or hybrid generation under current and expected future prices.

I have shown that PV minigrids can be designed to provide different levels of electricity access to rural communities in Uttar Pradesh, including increasing it over time, and can be designed to complementarily integrate into the local Bahraich District grid network which was described in chapter 7 that either already exists or if the grid is extended towards it. Under certain conditions I explored it may even be the case that PV minigrids can provide reliable electricity at a lower cost, and with much lower GHG emissions, than an adjacent grid network. My results allow me to conclude that PV minigrids are technically and economically viable in providing reliable power to communities in Uttar Pradesh and that they can mitigate current GHG emissions from kerosene lamps, diesel generators and the Indian grid network.

The results I have presented are applicable to the case study locations in Uttar Pradesh I consider, and specifically rural areas of Bahraich District, but as discussed in chapter 5 and elsewhere many of the situations I have modelled will be relevant to other scenarios across India and beyond. Local costs and climatic data will be specific to Uttar Pradesh but the

results I have presented could be extended to similarly remote and unelectrified communities across the states of northern India. Device ownership and usage patterns would likely be different in other areas owing to varying levels of affluence, cultural factors, and the times of sunrise and sunset. Extrapolating my results to southern states may be less valid as climatic conditions and levels of poverty and electrification can vary considerably, in addition to the reliability of the grid network. Furthermore the socioeconomic data I gathered, modelled and used to draw my conclusions will not be representative of the wider rural Indian context, either for rich regions of Uttar Pradesh or similarly poor regions of other states. As a result of these factors my conclusions and subsequent recommendations are limited to low-income rural areas of Uttar Pradesh, or Bahraich District at their most restrictive, but constitute a representative case study of remote areas in the region I have focused upon. I acknowledge that extrapolation to similar scenarios and communities elsewhere in India would be possible but should be accompanied by a suitably robust analysis of the differences between the two situations.

I have not explored many of the wider social and political issues in this work and as such cannot comment on them in detail, but my results and conclusions may be used to inform them. As stated previously, my work is specific to Uttar Pradesh and could potentially be used to inform the policy of that state on PV minigrids; my results align with the goals of the first iteration of this policy, the first of its kind in India, which was published in 2016 and the subsidy schemes it includes would reduce the costs of the PV minigrids I have described and would further support my conclusions of their potential to mitigate GHGs and facilitate energy access. National-level legislature for all of India would require much further investigation into the benefits of energy access provided by a variety of sources, including minigrids supplied by different technologies, solar home systems and grid extension, and would be likely to focus on the total potential to provide households with electricity quickly and cheaply, rather than with the goal of mitigating GHG emissions. Nevertheless, my

conclusions that PV minigrids have a significant potential to mitigate GHGs by supplying affordable energy for energy access in Uttar Pradesh would be able to contribute to the development of such a policy in combination with many other analyses.

In order for PV minigrids to achieve their maximum impact will need to be supported by government policies and regulations, technical research and development and innovative business models. If this is achieved then they will be able to satisfy many government and international development agendas [2, 34, 54, 119] and PV minigrids will be able to provide sustainable, affordable and reliable electricity to rural communities whilst significantly reducing GHG emissions. Furthermore the additional cobenefits that clean electricity access can bring, for example reducing indoor air pollution, providing opportunities for employment, increasing hours of study for children and improving community safety have not been quantified in this work but would likely further add to the body of evidence in favour of using PV minigrids for sustainable development.

8.4 Future work

8.4.1 Emerging PV technologies

Organic photovoltaics

As OPV technology develops it will be essential to continue research into its potential applications. Performance improvements and cost decreases, especially if commercial scale manufacture is achieved, could open up new avenues for the technology to be applied to scenarios where flexible, lightweight, low cost and low GHG modules would have a unique advantage. It may be the case that OPV modules with sufficiently long lifetimes would one day provide a cost-competitive alternative to mature technologies and diesel generation in the context of rural electrification in India. This was explored in this work, and further in other work using CLOVER [239], but it will be necessary to verify these predictions with accurate

and recorded performance and cost data, rather than projected data, once these improvements are achieved.

The application of OPV to solar home systems should also be explored. The area available on the rooftop of a typical rural household would be sufficient for an OPV module to be installed and the lightweight nature of the module would further facilitate this. The relatively low energy requirements of solar home systems would also be adequately met by an OPV module of this size. Finally as solar home systems are typically expected to provide electricity services for periods on the order of years, rather than decades as would be the case for minigrid or national grid infrastructure, the relatively short lifetime of the OPV modules may be less of a hinderance if the entire solar home system is to be replaced, upgraded or renovated at the same time.

Concentrating photovoltaics

As is the case for OPV, advancements in CPV technology should be accompanied by research into their prospective applications. Multijunction solar cells used in CPV systems are likely to continue breaking efficiency records and provide the highest-performing systems which will remain well-suited to locations with high irradiance and little cloud cover. In the future they will need to capitalise on these opportunities by reducing manufacturing costs, allowing them to combine efficient energy generation with lower system investments and to achieve a cost of electricity competitive with those of mature PV and other renewable technologies. Systems using CPV modules, both those investigated in chapter 4 and others, have been shown to provide extremely low GHG emissions in comparison to both fossil fuel generation and other renewable sources. It may be this feature which leads to greater deployment of CPV systems: as the need to mitigate GHGs grows, technologies which can provide electricity at lower and lower emissions intensities may experience greater deployment.

8.4.2 PV for rural electrification

Energy systems modelling

This work has demonstrated an application of the CLOVER modelling framework applied to specific scenario in rural India. Although I have aimed for my work to be appropriately generalisable it is inevitable that the results that are presented and the conclusions that are drawn are dependent on the considered application and the parameters that I chose. In particular, the load growth scenarios that I use in my modelling work are consistent with the aspirations of international organisations and the expectations of the stakeholders we discussed them with for rural communities in India but, as with all projections, these may not be realised in the future. Further work should be undertaken to analyse the effect of different predictions for growth in electricity demand for remote communities in Uttar Pradesh, both in terms of the eventual total load demand and the rate at which this total is achieved, and the effects this would have on system design strategies. Furthermore a variety of combinations and penetrations of devices for both domestic and commercial services should be investigated as this may have additional impacts on system design owing to, for example, differences in the seasonality of their utilisation. These recommendations are all possible within the CLOVER modelling framework; using the data I have gathered this could be used to further investigate systems in Uttar Pradesh, or if additional relevant data were gathered it could be used to explore systems deployed in other geographic regions.

In this work I have considered in detail the usage of c-Si PV for rural electrification. The work undertaken in chapter 7 could be repeated for the other PV technologies considered in chapter 3 to assess any potential variation in results or identify any advantages of the other technologies. In particular reassessing CdTe would provide an informative insight into whether another mature and viable PV technology should be considered for use in rural PV minigrids, both in terms of its cost and potential to mitigate GHGs, in addition to c-Si PV. Owing to their lower embedded emissions it is likely that other PV technologies

would have a greater potential to mitigate GHGs but this would need to be assessed in the context of a continued market dominance of c-Si PV. Furthermore it would be valuable to explore the effects of different kinds of energy storage technologies, perhaps comparable to the study presented in chapter 3, to investigate the most suitable battery chemistry for rural electrification.

Other renewable energy technologies that have been proven viable for rural electrification may also provide a significant potential to mitigate GHG emissions. The capability to integrate wind and hydropower electricity generation in minigrid systems has been included in the CLOVER model and used for analysis [240] but a detailed assessment comparable to the work presented here has not yet been undertaken. Furthermore minigrids supplied by bioenergy systems, for example by using biomass gasifiers, are relatively common in India and other developing countries. Integrating the capability for modelling bioenergy systems using CLOVER could provide a valuable comparison between its appropriateness for different applications and the appropriateness of PV, and identify the circumstances under which each technology would be superior. It would also be possible to assess any potential for the two technologies to work in concert to provide electricity as part of a wholly renewable hybrid system, displacing diesel generation.

The effect of the reliability of the grid network should also be investigated as in this work only one profile of grid reliability was used. Further work could be undertaken to assess the impact of different levels of total grid service, for example the total numbers of hours available per day, and the effect of reliability at different times of the day, for example greater or lesser availability in the evening times which would significantly affect kerosene usage. This could be used to represent the availability of the grid in other regions of India than the one I have considered or other parts of the world with similar issues. This would also affect the ability of on-grid systems with grid storage to mitigate GHG emissions or not. Introducing grid connectivity in later years, rather than at the start of the optimisation period

as considered here, may also affect the viability of PV systems. Furthermore, the potential of PV minigrids to mitigate GHG emissions would be affected if the emissions intensity of the grid network was varied to reflect various different levels of renewables penetration at the national scale, in line with the implementation of government policies.

Finally, the energy systems modelling framework described in this work could be used to simulate the performance of solar home systems. Many of the modelling processes would be very similar or identical to those used in this work, albeit at a much smaller scale, but could be used to assess the potential benefits, costs and differences in GHG emissions made available by using smaller single-household systems. This concept has been explored somewhat [241] but could be developed further to compare the benefits of different strategies for rural electrification in India and elsewhere.

Estimating rural electricity demand

The analysis in chapters 5 and 7 relies on detailed and accurate primary data. The limitations of the fieldwork meant that data was collected across several villages in Bahraich District; whilst this provides an overview of the situation of the district, it is not necessarily as applicable to a specific case study in a single village. In June 2017 a followup survey of households was undertaken by Philip Sandwell, Alexander Mellor, Clementine Chambon and Amit Saraogi in the village of Sarvantara, Bahraich District to provide the baseline for an impact assessment of the first minigrid deployed by Oorja Development Solutions Ltd. The survey used and the data collected were the same as those from chapter 5 of this work but with additional questions relevant to the minigrid deployment. These data would provide a localised and more robust case study for the energy access situation of a specific example village in rural India.

Furthermore, energy usage in selected households connected to this minigrid will be remotely monitored for a period of two years and the data gathered from this project could be

used to synthesise either community-level load profiles or, with further analysis, household- or even device-level load and utilisation profiles. As the data is being collected at the scale of minutes it will provide a higher resolution than the data collected in chapter 5 and, as it is being recorded electronically and *in situ*, it will likely also result in a higher degree of accuracy in estimating the electricity usage in rural Indian communities. Processing this data into the formats used by CLOVER would be straightforward and would help inform system design in the future.

Financial analysis

The financial and economic data used in my analysis is specific to the region of Uttar Pradesh I investigated and similarly specific conditions would exist elsewhere. For this reason, if the results of this work were extrapolated beyond Uttar Pradesh or India it would be important to consider the effects of changes in local costs, for example for system equipment, as well as financial climate, for example the rate of loan repayments. Any such extrapolations should be verified by reanalysing systems using locally appropriate data and case studies.

The financial analysis used to assess the suitability of different compositions of systems could be further developed. The inclusions of subsidies on renewable energy, for example, would lower the cost of PV minigrid systems and may change the composition of optimum hybrid systems. The expenditures on system components could be annualised to reflect new financing models being made available to minigrid developers and the discount rates and working costs of capital could be altered to understand the effects of investment risk in the project. This would provide a more well-rounded analysis in addition to the relatively unidimensional quantification used in this work and would more accurately represent some of the business model challenges that are being faced by practitioners.

These financial additions may affect the optimum strategy for system sizing. Large up-front subsidies on initial capital expenditures may promote system oversizing, or higher loan

repayments in the long term may have the opposite effect. These would have implications on the growth of the capacity of the system over time and may affect whether PV minigrids or hybrid minigrids, for example, are the most effective investment over the lifetime of the system. Further work could be done to quantify these effects and compare the financial mechanisms that would incentivise the deployment of systems with the lowest GHG emissions, for example.

Finally, throughout this work I have relied on cost estimates and projections to assess which minigrid system can provide the most affordable cost of electricity. This is determined, in part, by the cost of components and system inputs and so a sensitivity analysis with regards to the costs of PV modules, battery storage and diesel fuel may reveal sharp transitions in the design of optimum systems, as was found in chapter 3. Quantifying the impacts of future system costs may be possible using further energy system simulation and optimisation and would help researchers identify future trends.

8.5 Final summary

In this chapter I have summarised the conclusions from this work and presented the potential of PV technologies to mitigate GHG emissions in the scenarios that I have considered. I have found that emerging PV technologies may be able to have an impact on GHG mitigation if they can reach sufficient commercial scale, whilst mature PV has a demonstrable effect on reducing overall GHG emissions in the context of rural electrification. I have also outlined potential future research directions that would build on the work presented here and would continue the assessment of PV technologies in providing reliable, affordable and sustainable energy for all.

Finally, the methodology used in this work could be extended to rural areas in other regions of India and other countries. India has provided a suitable case study but similar rural electrification issues exist in developing countries around the world, and in partic-

ular Sub-Saharan Africa. Each country will also feature unique challenges and the most appropriate energy sources, and the energy services that they will aim to satisfy, will vary between countries and between regions within the same country. I hope that the research suggested here could be used to further investigate the GHG emissions mitigation potential of photovoltaic technologies.

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Appendix B

Modelling codes

Introduction

This appendix contains a brief description of the codes used in chapters 3 and 5 to 7. The codes are available for download from the links provided.

Code used in chapter 3

The code in chapter 3 was written in Python 2.7 and is available by **clicking here** or visiting goo.gl/S7Jk5Q. The model was originally designed in Microsoft Excel by Divyam Nagpal and was converted to Python by Alvin Chan in order to increase its potential computational functionality; Philip Sandwell further developed, tested and validated the model and updated its parameters to be relevant to the context explored in this work.

The model is composed of a central code file, PVBOT.py, which contains the simulation and optimisation methods used to analyse the performance of PV and hybrid minigrid systems and compare their impacts against diesel-only systems and the national grid. The code draws on meteorological and data supplied by .csv and .txt files and can be used to plot figures of the results. Further details of how the code operates are available in the supplementary information of Sandwell et al. [111].

Code used in chapter 5

The code in chapter 5 was written in MATLAB and is available by **clicking here** or visiting goo.gl/ffjxAy. The code was written by Philip Sandwell.

The results from each questionnaire was compiled and stored in Microsoft Excel files for basic analysis and then the relevant components were imported into MATLAB for further analysis and the plotting of boxplots and cumulative distributions. MATLAB was used for Monte Carlo simulations of the electricity demand of the community, owing to its superior

computational abilities in comparison to Excel, and was also used to plot the results of these simulations.

Code used in chapters 6 and 7

The code described in chapter 6 and used in chapter 7 was written in Python 2.7 and is available by **clicking here** or visiting goo.gl/iGdrvt. The code was written by Philip Sandwell. Python was chosen as the scripting language owing to its superior computational capabilities and flexibility.

CLOVER is composed of several scripts, each of which performs various related functions. Most of the code operates by generating, manipulating, storing, accessing and processing data structures whose elements correspond to time steps in the simulation. Parameters used for each function are stored in the scripts themselves and large data inputs and outputs are stored as .csv files to be accessed by the scripts. Generation from PV is calculated by PV.py and draws on meteorological data to return the generation output of 1 kW_p of installed capacity. Diesel.py controls the usage of the backup diesel generator and Grid.py provides the availability of the grid. Devices.py returns the numbers of each domestic device in the community at a given time, and Load.py uses this to return the electrical load of each device type; both of these functions are integrated into the same module for commercial devices in Commercial.py.

Simulations are performed by Energy_System.py drawing on the outputs and functions of the other modules. Optimisations are performed by Optimisation.py which runs the simulations and uses their information to assess their financial and environmental impact using Finance.py and Environmental_Impact.py respectively. Analysis.py uses the outputs of the optimisation process and others to analyse and plot data and was used to generate the figures used in chapter 7. Other miscellaneous scripts include Data_conversion.py, used to convert between data structures of difference lengths of time, and Grid_Meters.py, which

was used to analyse data from the smart meters that were installed to monitor the reliability of the grid.

The CLOVER model has been under continuous development and the version available from this appendix represents the version that was used for the analysis undertaken in this work. Further development of the model by Philip Sandwell, Scot Wheeler, Alexander Mellor, Ajay Gambhir and Louise Alter has increased its functionality but was not used in this work and is not included here. We plan to combine these developments, refine and simplify the code and make CLOVER both more accessible and freely available in the future.

Appendix C

Energy Access Survey

Questionnaire Number

OORJA HOUSEHOLD ENERGY QUESTIONNAIRE, 2015

INSTRUCTIONS FOR INTERVIEWER

Text in this style (bold)must be read to the survey participant.

Text in this style (italics) is for the instruction of the interviewer and should not be read to the participant.

Text in this font is for survey responses. These should be used to inform the interviewer of the correct format of responses.

Mark with a tick in the boxes [✓]where appropriate.

THE SURVEY BEGINS NOW.

Purpose and Benefit of the Study

The aim of this study is to accurately assess the household energy needs of your community. 'Oorja' is a company run by a team of four people. We are interested in establishing a biomass energy system that would serve your village. This could bring benefits such as clean and affordable electricity, cooking gas and a soil enhancement substance that will improve soil fertility and reduce fertilizer and water requirements.

In order to assess the requirements of your community we are surveying local stakeholders to learn about their needs.

Consent

This survey will ask questions about your personal situation, including your family and

finances. Information collected from you will be anonymous and identifying personal data will not be shared with anyone.

Participation in this study is entirely voluntary. Declining participation in this interview will not affect your access to any future Oorja services. At any time if you do not wish to answer a question, or wish to terminate the interview, please tell your interviewer.

Please answer the questions as accurately and honestly as possible as this will allow Oorja to potentially provide the best service to you in the future.

The duration of this interview is approximately twenty minutes. If you consent to this study, please sign your name below.

Place/Village Name:

District:

Household ID (from list):

Interview Date:

Interviewer ID:

Participant Name:

Participant Signature:

Interviewer Signature:

This survey was conducted in

[Hindi / English / Other: _____]

A. FAMILY AND FINANCIAL BACKGROUND

A.1 **Who lives in your household? Please tell me their age, sex, primary occupation, level of education. After listing the occupants, please specify the head of the household.**

Tick if unanswered [ ]

Interpret the response to fit as closely as possible to the categories below. If no category is suitable, use "9" (Other) and specify the response below.

	Occupation Codes	*Education Codes*
1	*Farmer*	*No formal education*
2	*Labourer*	*Primary (I-V)*
3	*Shop owner*	*Upper primary (VI-VIII)*
4	*Government employee*	*Secondary*
5	*Housewife*	*Bachelors*
6	*Student*	*Higher education*
7	*No employment*	*Vocational*
8	*Retired*	*Apprenticeship*
9	*Other*	*Other*
[Specify]		

RELATION TO PARTICIPANT [Example: Husband/wife, son/daughter, father/mother, grandfather/grandmother, cousin, friend]	*SEX [M/F]*	*AGE [YEARS]*	*OCCUPATION [Use code]*	*EDUCATION [Use code]*	*HEAD OF HOUSEHOLD? [Tick if yes]*
Participant					

A.2 **What was your total household income last year?**

Tick if unanswered [ ]

Total:

NUMBER [ ] INR

If you are a farmer, what was your seasonalincomein the last year?

Kharif (rice):

NUMBER [ ] INR

Rabi (wheat):

NUMBER [ ] INR

Inter-season:

NUMBER [ ] INR

A.3 **What is your personalmonthly income?**

Tick if unanswered [ ]

NUMBER [ ] INR

A.4 **What was your personal income last month?**

Tick if unanswered [ ]

NUMBER [ ] INR

*A.5***In the last month, what was your expenditure on the following?**

Tick if unanswered [ ]

Food:

NUMBER [ ] INR

Clothes:

NUMBER [ ] INR

Transport:

NUMBER [ ] INR

Farming inputs:

NUMBER [ ] INR

Festivals:
NUMBER [ ] INR
Education:
NUMBER [ ] INR
Health:
NUMBER [ ] INR
Water, cooking and other fuels:
NUMBER [ ] INR
Other *[specify]:* [ ]
NUMBER [ ] INR

A.6 **How many <u>rooms</u> are there in your home?**
Tick if unanswered [ ]

NUMBER [ ] rooms

A.7 **Do you <u>own</u> your home?**
Tick if unanswered [ ]

Yes **[ ]**
No, Rented **[ ]**
No, Other **[ ]**
If No, Other then specify: [ ]

<u>Farmers only (asset ownership)</u>

*A.8***If you are a farmer, do you <u>own and use</u> your land, or both?**
Tick if unanswered [ ]

User [ ]
Owner [ ]
Both [ ]

A.9 **What is the <u>size</u> of your plot of land and how long have you been the user/owner?**

Tick if unanswered [ ]

<u>Farm size</u>:

Marginal(< 1 ha = < 4 bigha) [ ]
Small (1-2 ha = 4-8 bigha) [ ]
Semi-medium (2-4 ha=8-16 bigha) [ ]
Medium (4-10 ha=16-40 bigha) [ ]
Large (> 10 ha = >40 bigha) [ ]

<u>Land tenure</u>:

NUMBER [ ] months [ ] years

A.10 **Do you own or raise <u>livestock</u>?**

Tick if unanswered [ ]

Yes [ ] **No** [ ]

B. PERSONAL ACTIVITIES

B.1 **Yesterday, how did you spend your day? For example, sleeping from 22h to 06h. The options are: sleeping, working (including any activity which generates income), cooking (including any food preparation), reading/studying, social activities (including with family and friends), travelling (for example to collect firewood or to market) or other activities (please specify).**

Tick if unanswered [ ]

More than one circle can be shaded for each hour. Horizontal lines denote approximate times of sunrise and sunset.

HOUR	SLEEP	WORK	COOK	READING STUDY	SOCIAL RELIGIOUS	TRAVEL	OTHER [SPEC]:
00	O	O	O	O	O	O	O
01	O	O	O	O	O	O	O
02	O	O	O	O	O	O	O
03	O	O	O	O	O	O	O
04	O	O	O	O	O	O	O
05	O	O	O	O	O	O	O
06	O	O	O	O	O	O	O
07	O	O	O	O	O	O	O
08	O	O	O	O	O	O	O
09	O	O	O	O	O	O	O
10	O	O	O	O	O	O	O
11	O	O	O	O	O	O	O
12	O	O	O	O	O	O	O
13	O	O	O	O	O	O	O
14	O	O	O	O	O	O	O
15	O	O	O	O	O	O	O
16	O	O	O	O	O	O	O
17	O	O	O	O	O	O	O
18	O	O	O	O	O	O	O
19	O	O	O	O	O	O	O
20	O	O	O	O	O	O	O
21	O	O	O	O	O	O	O
22	O	O	O	O	O	O	O
23	O	O	O	O	O	O	O

OTHER ACTIVITY: [ ]

B.2 **Would you like to spend more, less or the same amount of time doing these activities?**

Tick if unanswered [ ]

Sleep:	[ ] More	[ ] Less	[ ] Same
Work:	[ ] More	[ ] Less	[ ] Same
Cooking:	[ ] More	[ ] Less	[ ] Same
Read/Study:	[ ] More	[ ] Less	[ ] Same
Social:	[ ] More	[ ] Less	[ ] Same
Travel:	[ ] More	[ ] Less	[ ] Same
Other:	[ ] More	[ ] Less	[ ] Same

C. ENERGY SERVICES

C.1 **Do you have a connection to grid electricity?**
Tick if unanswered [ ]

Yes [ ] **No** [ ]

If yes, during what times did you have access to grid electricity yesterday?

Time: [ ] — [ ] **AM/PM**
[ ] — [ ] **AM/PM**

C.2 **Do you have access to off-grid electricity?**
Tick if unanswered [ ]

Yes [ ] **and it is** **Diesel** [ ]
Solar [ ]
Wind [ ]
Biomass [ ]
Other [ ]
Specify: [ ]

No [ ]

C.3 **How many of the following energy services does your household currently own in total?**
Tick if unanswered [ ]

Lighting:
Fixed Light: [ ] NUMBER
Solar Lamp: [ ] NUMBER
Kerosene Lamp: [ ] NUMBER
Torch: [ ] NUMBER
Candle: [ ] NUMBER
Other: [ ] NUMBER
Specify: [ ]

Batteries:

Car:	[ ] NUMBER
Solar:	[ ] NUMBER
Other:	[ ] NUMBER
Specify:	[ ]

Food Preparation:

Firewood Stove:	[ ] NUMBER
Gas Stove:	[ ] NUMBER
Electric Stove:	[ ] NUMBER
Manure Stove:	[ ] NUMBER
Other:	[ ] NUMBER
Specify:	[ ]

General:

Cell phone:	[ ] NUMBER
Radio:	[ ] NUMBER
Television:	[ ] NUMBER
Fan:	[ ] NUMBER
AC Unit:	[ ] NUMBER
Refrigerator:	[ ] NUMBER
Other:	[ ] NUMBER
Specify:	[]

C.4 **<u>Yesterday</u>, at what time did you use the energy services? For example Solar Lamps from 05h to 06h and from 19h to 22h.**

Tick if unanswered [ ]

More than one circle can be shaded for each hour. Horizontal lines denote approximate times of sunrise and sunset.

HOUR	FIXED LIGHT	SOLAR LAMP	KEROSENE LAMP	TORCH	CANDLE	OTHER LIGHTING	FIREWOOD STOVE	GAS STOVE	ELECTRIC STOVE	OTHER STOVE	RADIO	TELEVISION	FAN	AC UNIT	CELL PHONE [CHARGING]	OTHER GENERAL
00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
01	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
02	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
03	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
04	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
05	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
06	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
07	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
08	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
09	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

C.5 **How often do you travel to access the following services? How far away is the service located? How much does it cost?**

Tick if unanswered [ ]

Interpret the response to fit as closely as possible to the categories below. If the activity does not apply to the participant then leave the box empty.

Code	*How often:*	*How far (approximate)*
1	*Daily*	*Within village OR Less than 30 minutes*
2	*2-3 times per week*	*2-5 km OR 31 minutes – 1 hour*
3	*Weekly*	*5-10 km OR 1–2 hours*
4	*2-3 times per month*	*More than 10 km OR More than 2 hours*
5	*Monthly*	
6	*Less than monthly*	

In the 'per' column, state the unit which is being bought, e.g. 'per candle', 'per litre' (for kerosene or diesel), 'per charge' (for battery).

	ACTIVITY	HOW OFTEN	HOW FAR	COST	per
BUY	KEROSENE FOR LAMP				
	CANDLES				
	TORCH				
	BATTERIES				
	FIREWOOD				
	COOKING GAS				
	DIESEL FOR GENERATOR				
	OTHER [SPECIFY]				
COLLECT	FIREWOOD				
	MANURE				
	OTHER				

CHARGE	SOLAR BATTERY				
	CAR BATTERY				
	CELL PHONE				
	OTHER [SPECIFY]				

SPECIFY BUY [OTHER]: [ ]
COLLECT [OTHER]: [ ]
CHARGE [OTHER]: [ ]

Appendix D

Modelling parameters used in chapter 7

Introduction

This appendix contains a compilation of the parameters used in chapter 7. Many of these values, and any not explicitly listed here, are the same as used in chapter 3 for comparability.

Simulation and optimisation

The parameters used in the simulation and optimisation process are shown in table D.1. Timesteps are taken to be unitless counters of simulation time equivalent in size to one hour. Device options depend on whether domestic or commercial loads were chosen. Initial capacity and jump values were chosen manually to minimise computing time and were selected such that the optimum system for each simulation period was always found.

Table D.1 Simulation and optimisation parameters.

Parameter	Symbol	Value	Units	Notes
Optimisation start time	${t^1}_{\text{start}}$	0	timestep	–
Optimisation end time	$t_{\max}$	175,200	timestep	Equivalent to 20 years
Optimisation period	–	20	years	Total time period considered
Simulation intervals	N_{int}	5	–	Number of simulation intervals
Simulation period	–	4	years	Length of simulation interval
Sufficiency criterion	$\overline{B}$	–	–	Blackout percentage
Optimisation criterion	$\mathscr{L}(\Psi)$		\$/kWh	System LCUE
Renewables options	ξ_R	{PV}	–	PV generation only
Device options	ξ_D	Various	–	Dependent on demand type
PV initial capacity	$\xi^1_{\alpha^{\text{PV}}}$	Various	–	Scenario dependent
PV capacity step	$\alpha^{\text{PV}}_{\text{step}}$	1	kW	1 kW resolution
PV jump minimum	$\lambda^{\text{PV}}_{\min}$	Various	–	Scenario dependent
PV jump maximum	$\lambda^{\text{PV}}_{\max}$	Various	–	Scenario dependent
Storage initial capacity	ξ^1_{Bat}	Various	–	Scenario dependent
Storage capacity step	β_{step}	1	kWh	1 kWh resolution
Storage jump minimum	$\lambda^{\text{Bat}}_{\min}$	Various	–	Scenario dependent
Storage jump maximum	$\lambda^{\text{Bat}}_{\max}$	Various	–	Scenario dependent

Community

The parameters for community size are shown in table D.2. A functional unit of one community of 100 households was chosen as this both represents a typical village or hamlet size in Uttar Pradesh and also can be easily extrapolated to larger community sizes.

Table D.2 Community parameters.

Parameter	Symbol	Value	Units	Notes
Initial community size	H_0	100	household	Assumed to be homogenous
Community growth rate	g_y	1.5	%	Annual
Final community size	–	135	household	From above, after 20 years

Device ownership

Parameters for device ownership shown in table D.3 were informed by the fieldwork outlined in chapter 5, data from the Census of India, and through interviews with government officials, NGOs and minigrid companies during fact-finding meetings in Delhi and at a conference in Bangalore in July 2016. They were chosen to provide a representative energy demand in line with the aims of providing reliable and increasingly valuable energy access to rural communities in India.

Table D.3 Device parameters.

Demand type	Device	n_0^i	$n_{\max}^i$	p^i	q^i	W^i	Notes
Domestic	LED	2.0	4.0	0.04	0.50	3	From chapter 5
	Phone charging	2.2	3.0	0.02	0.20	5	From chapter 5
	Fan	0.1	1.0	0.04	0.30	10	[55, 59, 223]
	Television	0.08	0.90	0.03	0.25	10	[55, 59, 223]
	Refrigerator	0.0	0.20	0.02	0.20	45	[35, 224]
Commercial	SME	0.05	0.30	0.05	0.25	100	From stakeholders,
	Workshop	0.05	0.20	0.02	0.20	350	chapter 7 and
	Mill	0.01	0.10	0.02	0.20	750	[35, 224, 231, 232]
Kerosene	Lamp	3.4	4.0	0.02	0.10	–	From chapter 5

Technical performance

The performance of the energy systems technologies used in the modelling process are summarised in table D.4. These are taken from a combination of technical datasheets, academic and industrial publications and defined characteristics for the system.

Table D.4 Summary of technical parameters.

Parameter	Value	Unit	Notes
PV azimuth	180	°	South facing, defined
PV elevation	10	°	From horizontal, defined
PV lifetime	20	years	From [16]
PV NOCT	45.7	°C	From [242]
PV thermal performance	-0.45	%/°C	From [242]
Albedo	0.20	–	From [243]
Battery depth of discharge	50	%	From [75]
Battery C-rate	0.33	–	From [75, 244]
Battery lifetime	1200	cycles	From [244]
Battery round-trip efficiency	90	%	From [75, 245]
Diesel fuel usage	0.4	litres/hr per kW	From [246]
Diesel minimum load factor	35	%	From [95, 247]
Power conversion efficiency	95	%	From [74, 233, 234]
Network transmission efficiency	95	%	From [235]

Financial and environmental impacts

The financial and environmental impacts used in the modelling process are shown in tables D.5 and D.6. Where relevant, the values shown are per unit of nameplate capacity. US dollars (USD, $) are used as the currency for the simulations and any costs in Indian rupees (INR) were converted at a rate of 65.0 INR per USD.

Table D.5 Summary of financial impacts.

Item	Value	Unit	Notes
PV module (c-Si)	500	$/kW$_p$	From [5]
System installation and BOS	1310	$/kW$_p$	From [111]
Battery storage (Li-ion)	300	$/kWh	From [137, 145, 138]
Grid extension	5200	$/km	Plains terrain, from [44]
Grid electricity	2.75	INR/kWh	From [226]
Diesel generator	160	$/kW	From [61, 87]
Diesel fuel	56.1	INR/litre	From [149]
Kerosene lamp usage	0.48	INR/hour	From chapter 5
PV cost decrease	3.0	% p.a.	From [5]
Battery cost decrease	3.0	% p.a.	From [137, 145, 138]
Discount rate	10.0	% p.a.	From [61, 75, 104]

Table D.6 Summary of environmental impacts.

Item	Value	Unit	Notes
PV module	2.70	kgCO_{2eq}/W$_p$	Chinese manufacture, from [17, 248]
Battery storage	108.3	kgCO_{2eq}/kWh	From [142, 249]
Balance of systems	1.5	kgCO_{2eq}/W$_p$	From [250]
Grid	790	gCO_{2eq}/kWh	From [108]
	15.5	tCO_{2eq}/km	Extension, from [44]
Diesel fuel	2.7	kgCO_{2eq}/litre	From [251, 246]
Kerosene lamp usage	0.55	kgCO_{2eq}/hour	From [201]