Optimizing the Design of Off-Grid Micro Grids Facing Interconnection with an Unreliable Central Grid Utilizing an Open-Source Simulation Tool

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Hiermit erkläre ich, dass ich die vorliegende Arbeit selbstständig und eigenhändig sowie ohne unerlaubte fremde Hilfe und ausschließlich unter Verwendung der aufgeführten Quellen und Hilfsmittel angefertigt habe.

Berlin, den 24. Juni 2019
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Optimierung des Designs von Off-Grid Micro Grids mit zukünftigem Anschluss an ein unzuverlässiges Stromnetz durch ein Open-Source Simulationsprogramm

Während nationale Stromnetze traditionell vorherrschende Elektrifizierungsprojekte von Regierungen sind, enthalten neuere, mehrspurige Pläne auch dezentrale Versorgungsoptionen, z.B. off-grid Micro Grids. In ihrer Studie *Energy for All Case*, die vollständige Elektrifizierung bis 2030 zum Ziel hat, schätzt die IEA ab, dass 44 % der Haushalte durch Micro Grid elektrifiziert werden. Unsicherheit bezüglich des Stromnetzausbaus ist das Haupthindernis ihrer Implementierung: Investoren sind besonders vorsichtig, wenn ein möglicher zukünftiger Netzausbau zum Projektort die Gefahr impliziert, dass die gesamte Investition zu versunkenen Kosten wird. Dadurch können ganze Gemeinschaften, die ansonsten gute Projektbedingungen aufweisen, ohne Strom verbleiben. Es gibt allerdings auch postitive Erfahrungen zum Anschluss eines Micro Grids zum Stromnetz. Doch Forschung zu solchen Betriebsoptionen, insbesondere verbunden mit versorgungsunsicheren nationalen Netzen, ist selten.
Diese Studie setzt an diesem Schnittpunkt an. Um mögliche Betriebsoptionen eines off-grid Micro Grids nach dem Anschluss an ein verlässliches sowie unsicheres nationalen Netzes zu evaluieren, wurde ein open-source Simulations- und Optimierungstool programmiert, das auf dem Open Energy Modelling Framework (oemof) basiert. Das simulierte Energiesystem kann einen Netzanschluss, Generator, Windkraftanlage, PV-Anlage und Batterien sowie Wechsel- und Gleichrichter enthalten, und sowohl DC- als auch AC-Bedarf versorgen. Die Kapazitäts- und Dispatchoptimierung kann eine jährliche Unterversorgung erlauben oder die Erfüllung eines Stabilitätskriteriums sowie einen minimalen Anteil von erneuerbaren Energien erzwingen. Aus den Ergebnissen werden die Systemkennzahlen berechnet: Versorgungssicherheit, regenerativer Anteil, Autonomie, Kapitalwert, Strombereitstellungskosten und Andere.
Das Tool wird angewendet auf und validiert durch eine Fallstudie, die auf einem Elekrifizierungsplan für den nigerianischen Staat Plateau basiert und 544 potentielle Projektorte beinhaltet. Das Paradigma, dass Micro Grids zu gestrandetem Kapital werden, wenn ein verlässliches Stromnetz den Projektort erreicht, wird bestätigt, sofern keine passenden Richtlinien vorhanden sind. Wenn allerdings das Stromnetz unsicher ist, können off-grid Micro Grids 17 % der Projekte ihre Gemeinde zu geringeren Kosten versorgen. Die Betriebsoptionen eines Micro Grids, das nach fünf Jahren off-grid Betrieb an das nationale Stromnetz angeschlossen wird, werden untersucht. Berücksichtigt sind on-grid Betrieb sowie Nachrüstung, Transformation zu einem Stromeinspeiser oder Stromverteiler, sowie Entschädigung and Stilllegung. Die Untersuchung stellt fest, dass die Betreiber eines Micro Grids einen fortlaufenden on-grid Betrieb, sofern Subventionen bereitgestellt würden, oder die Auszahlung von Entschädigungen bevorzugen. Wenn das Stromnetz unsicher ist, zöge der Betreiber hingegen Entschädigungen vor. Der Betrieb des Micro Grids wird in diesem Fall eingestellt, und die Gemeinschaft ohne sichere Versorgung zurückgelassen. Aus der Perspektive eines Elektrifizierungsplaners ist daher eine Fortführung des Betriebs vorzuziehen, da es die kostengünstigste Option darstellt, die Versorgungssicherheit garantiert. Aus diesem Grund sollten Staaten den Wert von Versorgungssicherheit einbeziehen und, neben Entschädigungen, auch Subventionspläne entwickeln, die zu einem fortlaufenden Betrieb von Micro Grids ermutigen, insbesondere wenn das nationale Stromgrid durch Versorgungsengpässe gekennzeichnet ist.

Stichworte:
Micro grids, Ankunft des nationalen Stromnetzes, Blackouts, Elektrifizierungsplanung

Optimizing the Design of Off-Grid Micro Grids Facing Interconnection with an Unreliable Central Grid Utilizing an Open-Source Simulation Tool

While national grids are traditionally the predominant electrification projects of governments, recent multi-track plans also include the utilization of decentralized supply, such as off-grid micro grids. In their Energy for All Case aiming at full electrification by 2030, the IEA expects that 44 % of the households will gain electricity access by connecting to a micro grid. Uncertainty regarding national grid extension plans poses the main implementation barrier: Investors are especially cautious when the possibility of a future national grid extension to their project site implies the danger of rendering their whole investment to sunk costs. This can leave whole communities, otherwise feasible project sites, without electricity. However, there are successful examples of micro grid interconnection. But research into post-interconnection options, especially connected to often unreliable national grids, is rare.
This study contributes to this gap. In order to evaluate possible post-interconnection options of previously off-grid micro grids with the arrival of both a reliable and an unreliable national grid, an open-source techno-economic optimization and simulation tool based on the Open Energy Modelling Framework (oemof) is developed. The energy system simulated can include grid connection, generator, wind power, PV panels and storage as well as inverters and rectifiers, supplying both DC and AC demand. The capacity and dispatch optimization can allow annual shortage or require a stability or minimal renewable share criterion to be fulfilled. From the optimization results, the simulation tool calculates the systems performance indicators: supply reliability, renewable share, autonomy, Net Present Value, Levelized Costs of Electricity and others.
The tool is applied to and validated by a case study based on an electrification plan for the Nigeria's Plateau State, analysing 544 potential project sites. The paradigm of micro grids becoming stranded assets after the arrival of a reliable grid is confirmed, if no appropriate policies are in place. If, however, the arriving grid has a low supply reliability, 17 % of the project locations could supply their communities at lower cost off-grid.
The post-interconnection options of a micro grid, if the national grid was to arrive after five years of off-grid micro grid operation, are evaluated, considering: on-grid operation, capacity adaptation (refitting), transformation into a Small Power Producer (SPP) or Small Power Distributor (SPD) as well as reimbursement and abandonment. This reveals, that the micro grid operator would favour on-grid operation, if subsidies were provided, or reimbursement. In case of an arriving unreliable national grid however, the operator would choose reimbursement over continued operation. The micro grid operation would be terminated and communities left without reliable electricity supply. From an electrification planners perspective, continued on-grid operation of the micro grid would be preferable, as it is the least-cost option ensuring reliable supply.
Therefore, governments should consider the value of reliable supply and, next to reimbursements, develop subsidy schemes that encourage operators to continue operation, especially if the national grid experiences blackouts.

Keywords:
Micro grids, national grid arrival, blackouts, electrification planning

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Names and Abbreviations

AC	Alternating Current
CAPEX	Capital expenditure
cbc solver	Coin-or Branch and Cut Solver
CG	Central grid, a post-interconnection option
CRF	Capital Recovery Factor
DC	Direct Current
DisCo	Distribution company
DSM	Demand-Side Management
FIT	Feed-in Tariff
GDP	Gross Domestic Product
GHG	Greenhouse Gas Emissions
GHI	Global Horizontal Irradiation
GIS	Geographic Information System
IRR	Internal rate of return
LCOE	Levelized Costs of Electricity
LF	Load Factor of a diesel generator, i.e. share of maximum load utilized
MG	Micro grid
MILP	Mixed-Integer Linear Programming
MTF	Multi-Tier Framework of Electricfication
MYTO	Multi Year Tariff Order
NEPA	National Electric Power Authority (of Nigeria)
NERC	Nigerian Electricity Regulatory Commission
NESP	Nigerian Energy Support Programme
NESP study	Project *Nigeria Rural Electrification Plans* in the scope of the *Nigerian Energy Support Programme*
NPV	Net Present Value

O&M	Operation and Management
OEM	Optimal Energy Mix
oemof	Open Energy Modelling Framework, a Python library
Off-MG	Off-grid micro grid, a post-interconnection option
Off-MG-C	Micro grid designed for off-grid operation, connected to central grid for consumption, a post-interconnection option
Off-MG-CF	Micro grid designed for off-grid operation, connected to central grid for consumption and feed-in, a post-interconnection option
On-MG-C	Micro grid designed for on-grid operation, connected to central grid for consumption, a post-interconnection option
On-MG-CF	Micro grid designed for on-grid operation, connected to central grid for consumption and feed-in, a post-interconnection option
OPEX	Operational expenditure
PCC	Point of Common Coupling
PHCN	Power Holding Company of Nigeria
PPA	Power purchase agreement
PPP	Public-private partnership
PV	Photovoltaic
Pyomo	Pyomo is a library for python
Python	Python is an open-source programming language
REA	Rural Electrification Agency
RLI	Reiner Lemoine Institut
SDG	Sustainable Development Goal
SHS	Solar Home System
SOC	State of Charge of a battery
SPD	Small Power Distributor, a post-interconnection option
SPP	Small Power Producer, a post-interconnection option
TCN	Transmission Company of Nigeria
WACC	Weighted Average Cost of Capital

List of Symbols

A	Annuity [USD/a]
AF	Autonomy factor of an energy system [-]
C	Investment costs [USD]
CAP	Capacity [kW, kWh, kW$_p$]
CF	Cash flow [USD/a]
CRF	Capital recovery factor [1/a]
E	Accumulated electricity flow over a certain time frame [kWh/a, kWh/d]
FIT	Feed-in tariff [USD/kWh]
L	Limit of constraint [-]
NPV	Net Present Value [USD]
P	Power [kW]
PV	Present Value [USD]
RES	Renewable factor of an energy system [-]
T	Project duration [a]
η	Reliability of an electricity supply solution to supply demand [-]
a	Specific annuity [USD/unit/a]
c	Specific investment costs [USD/unit]
$capex$	Specific CAPEX [USD/unit]
d	Discounting factor [-]
k	Number of replacements [-]
$opex$	Specific OPEX [USD/unit/a]
p	Price per unit (variable costs) [USD/kWh, USD/l]
q	Used volume, eg. electricity [kWh/a, l/a]
r	profit margin [-]
t	Time, eg. year of grid arrival or component lifetime [a]
tax	Tax on component costs [-]
$wacc$	WACC [-]

List of Indices

$1st$	First
A	Abandonment
CG	Central grid
DG	Fossil-fuelled generator
MG	Micro grid
PV	Photovoltaic panels
RES	Renewable share
RE	Renewable energy sources
R	Reimbursement
$cons$	Consumption from the central grid
dem	Demanded
$distr$	Distribution grid
el	Electricity
ext	Central grid extension
$feedin$	Feed-in into the central grid
$fossil$	Fossil energy sources
$fuel$	Diesel fuel
gen	Generation
$global$	Global, electrification planner's point of view
$inst$	Installed
$intercon$	Interconnection or interconnected system
inv	Inverter
i	Item of a set
$last$	Last
min	minimal
$offmg$	Off-grid micro grid
$ongrid$	On-grid micro grid solution
op	Future operation costs of a system
pcc	Point of Common Coupling, transformer station
$proj$	Project
pv	PV system

p	Peak
res	Residual
$retail$	Retail revenues
$short$	Penalty due to shortage
$solar$	Solar
spd	Small Power Distributor
spl	Supplied
spp	Small Power Producer
s	Stability
$total$	Total
t	Connected to a certain year
$wear$	Variable costs due to wear
$wind$	Wind plant

1. Introduction

With electricity access improving public welfare, the goal of universal electricity access has joined the Sustainable Development Goals (SDGs) [1] and long been in the focus of countries of the Global South. Today, electrification plans include not only grid extension but also the utilization of decentralized supply [2], [3]. While standalone systems are introduced to areas with the least demand density, micro grids are used for communities with reasonably high demand [4, 40f]. They are competitive starting from a certain distance to the national grid [5, 203ff] and increasingly popular in electrification plans [4, p. 45]. In their Energy for All Case aiming at full electrification by 2030, the IEA expects that 44% of the households gaining access to electricity will do so by connecting to a micro grid. However, existing policies only lead to 25 % of the new connections through micro grid implementation [4, p. 49].
Micro grids are also an option if extension can not promise sufficient electricity supply: With insufficient generation and possibly faulty infrastructure, electricity provided by the national grid can be of low quality and ridden with frequent blackouts [6, p. 25].
Uncertainty remains if future grid arrival is expected at a potential micro grid project site: Requiring comparably high initial investments, uncertainty connected to its future operation in case of national grid arrival can limit the willingness of investors to support micro grid projects [7, 147f]. This can leave whole communities, otherwise suitable project sites, without electricity. The fear of the whole system being left as sunk costs remains, even though there are successful examples of micro grids connecting to the national grid [8], [9, pp. 285-311].
For an existing micro grid, grid arrival requires a techno-economic re-evaluation of whether and how to continue its operation. Frameworks for this procedure do not jet exist [4, p. 45]. With an unreliable national grid the decision whether to support, implement or continue the operation of a micro grid becomes more complicated.

Research Questions The number of research studies addressing post-interconnection operation of micro grids, especially in regards to an unreliable central grid, is very low [2]. Therefore, this thesis addresses this gap and aims to decrease the uncertainties related to micro grid projects by answering the following questions:

- How can an off-grid micro grid and its different post-interconnection options be simulated in an integrated manner?
- Can the paradigm be confirmed, that off-grid micro grids are abandoned when a reliable or unreliable national grid arrives?
- What are the different post-interconnection options of off-grid micro grids to a reliable or an unreliable national grid and what are their potentials?

By answering these questions, this thesis helps micro grid operators to evaluate the potential of their project site facing future grid arrival. It also can inspire policy designers to encourage micro grids implementation.

Methodology Addressing the research questions, an open-source techno-economic optimization and simulation tool is created, utilizing the Open Energy Modelling Framework (oemof) [10]. It evaluates the performance and economic feasibility off-grid PV-hybrid micro grids as well as their post-interconnection options after the arrival of a reliable as well as an unreliable grid. For that, it determines optimal capacities as well as their dispatch based on the annuity method. The tool is applied to the 544 potential project sites of a case study based on an electrification plan for Nigeria's Plateau State.
Three scenarios are evaluated: First, the simulation tool is validated by comparing its results with the initial electrification plan. Then, the paradigm of micro grids becoming stranded assets after the arrival of both a reliable and an unreliable grid is evaluated. Finally, the potential of future post-interconnection options is compared. Among these options are on-grid operation of the micro grid designed for off-grid supply, optimized design for on-grid operation, transformation into small power producer (SPP) and small power distributor (SPD) as well as reimbursement and abandonment. Both micro grid operator's and electrification planner's perspective are presented. A sensitivity analysis considering time of grid arrival completes the analysis.

Summary of results. The developed simulation tool is validated through the case study. Arrival of a reliable national grid introduces a competitor to the existing micro grid that has much lower Levelized Costs of Electricity (LCOE), threatening their operation. If the arriving grid, however, is unreliable, the national grid of 60 % reliability should not be extended to 18 % of the project locations, as they can be supplied at lower cost off-grid.
The potential analysis of different post-interconnection option shows that in case of reliable grid arrival after five years of off-grid micro grid operation, the micro grid operator can not compete with the electricity prices of the arriving national grid. On-grid operation would be preferable, but is only possible if subsidies were granted. Assumed Feed-In Tariff (FIT) and profit margin are not sufficient to make transformation into an SPP or SPD feasible. Reimbursement leads to as high LCOE from an electrification planner's perspective as continued operation. In case that the micro grid connects to an unreliable central grid, micro grid operators would choose reimbursement over continued operation. This micro grid termination, however, would deprive communities of reliable supply and would also be more expensive than continued operation from a electrification planners point of view. To ensure reliable supply and encourage micro grids to be build, governments should consider to introduce subsidies to cover for micro grids operational margins.

Structure of the master thesis In preparation for methodology and case study definition, a background research was performed (see Chapter 2), including an introduction to electrification access, electrification plans, micro grids and the issue of weak national grids. In Chapter 3 the methodology of this study is introduced. First, commonly used tools and the Open Energy Modelling Framework are presented. The developed simulation tool is outlined in Section 3.3. Both case study and scenarios are defined in Chapter 4. Their results are then described and discussed. Chapter 5 serves as a summary of the case study's results and points out their limitations. The research ends with a conclusion in Chapter 6.

2. Background research

The global push to reach the 17 Sustainable Development Goals (SDGs) of the UN by 2030 concentrates on a broad variety of aspects of daily life. Many of the addressed issues overlap with each other. Amongst those SDG 7 aiming at affordable, reliable, sustainable and clean energy access for all, is one of the goals with most diverse effect. A general introduction into the issue of electrification is provided in Section 2.1, including its definition, influence on public welfare and current trajectories. General electrification efforts of governments through electrification plans are presented in Section 2.2, including an overview over different technology solutions for providing electricity access for diverse consumers. The following Section 2.3 concentrates on one of these technologies and, thus, the focus technology of this master thesis: micro grid (MG) for rural electrification. Components of a MG as well as its planning process and implementation drivers and barriers are presented. In countries most struggling with bringing electricity access to their people, the central grids are often weak and overburdened by spiking demand, subsequently resulting in blackouts (see Section 2.4). This complicates the matter of post-interconnection MG operation, which is the focus of this master thesis.

2.1. Introduction to the issue of electrification

Sustainable Development Goal 7 plays an important role interconnecting the goals of fellow SDGs. To be able to reach SDG 7, it is necessary to have strong measurement metrics in place to evaluate its progress (see Section 2.1.1). With its far-reaching implications on education, health and welfare (see Section 2.1.2), it has been in the focus of governments, international unions, NGOs and companies for years. The current status on electricity scarcity is discussed in Section 2.1.3, while plans tackling electricity access are discussed in the next Section 2.2.

2.1.1. Defining electricity access

To tackle electricity scarcity, it is essential to have a strong and universal definition to measure electricity access.

Electricity access based on connection. The most basic definition labels a consumer as electrified if a electricity connection is available at home [11, p. 21]. While this enables a very quick categorization of households and can help to create a global picture on the state of SDG 7, this binary measure fails to take note of progress through off-grid solutions and can be misleading in case of unreliable or even lasting absence of electricity supply through a central grid. Additionally, it is often assumed that a community is electrified when a number of households have gained a connection, ignoring the number of people still left without access.

For example, in India, is considered that „a village [is] electrified if basic infrastructure such as schools are connected to the grid as well as at least 10% of households " [12]. In 2018, this has led India's prime minister Narendra Modi to announce, that the government had fulfilled a promise that would change the life of many Indians forever - as now every village of the country was electrified through grid connection. This, however, has been a polarizing claim, as about one-sixth of the population, amounting to 270 million people, still live without electricity [13], [12] and even interconnection can not guarantee reliable supply, as it is prone to 3.8 outages a month with 2 hrs duration on average [14].

To adequately track progress on electricity access initiatives, it is therefore essential to use a more detailed framework that is able to distinguish superficial access from actual access and also take into account the different levels of service provided. No universally applied framework for this assessment exists and surveyors and research groups might work with different assumptions, limiting the comparability of their results.

Multi-Tier Framework of Electrification. A more recently developed framework that eases the categorization of households depending on their electricity access status is the Multi-Tier Framework of Electrification (MTF), proposed by [15]. It defines electrification tiers from zero to five based on their services regarding possibly powered appliances, energy consumption in kWh/day, supply reliability as well as supply duration (see Table A.1). The definition helps to grasp the concept of energy poverty on a personal level. The demand and electrification status of a community can be evaluated based on the share of its population in the different access tiers. It might, however, be difficult for electrification planners to derive generalized demand profiles from the framework's definitions.

2.1.2. Implications of electricity access

Most appliances in daily life are powered by electricity, with their services reaching from lighting, meal preparation and hygiene up to everyday transport and communications. They supply basic needs and, especially considering communication devices, enable active participation in modern life. Electricity is also a necessity for most businesses today, may it be small- or large-scale shops, handicraft, medium-sized businesses or large-scale industries. As such, lack of electricity access is very limiting to individuals, communities and societies.
There wide-ranging implications are also mirrored in the fact that electricity access plays undoubtedly a supporting role in many of the SDGs, and, thus, is central to sustainable development:

- **Hunger and hygiene.** By increasing agricultural productivity i.e. powering water pumps for irrigation as well as providing electricity for fridges aiding in food preservation and for filtration systems providing clean drinking water, electricity can tackle SDG 2 (*Zero hunger*) and SDG 6 (*Clean water and sanitation*).
- **Health.** Electricity access also aids health, safety and medical care, addressing SDG 3 (*Good health and well-being for people*), i.e. through refrigeration of vaccines and powering medical devices, but also by providing simple services like lighting to maternity wards.

- **Individual wellbeing.** Electricity access can result in new or more efficiently operated small enterprises [16, p. 3], generating additional income and strengthening local economy, addressing SDG 1 (*No poverty*) and SDG 8 (*Decent work and economic growth*).
- **Education.** By providing electricity for lighting, modern forms of teaching and access to knowledge though the web, but also indirectly through the above described wealth-generation, electricity access has a positive influence on *Quality education* (SDG 4).
- **Equality.** Access to electricity can also help to tackle social issues and inequalities by allowing each individual to use the same livelihood increasing devices catering their basic needs and empowering them by granting access to information, not only on politics but e.g. on common practices for businesses or health care (SDG 10, *Reducing inequalities*). This can also lead to more *Gender equality* (SDG 5), as it can decrease the workload of women stuck in traditional gender roles or increase their knowledge and independence, also by empowering them to start their own businesses.
- **Country-wide issues.** Allowing access to modern forms of communication, electricity aids social and political discourse on the national and global level. More energy-intensive sectors, e.g. services or productive uses, are enabled and innovations for a more sustainable future can be adapted, e.g. sector-coupling in form of electricity powered public transport. This way, SDG 9 (*Industry, Innovation, and Infrastructure*), SDG 11 (*Sustainable cities and communities*), SDG 16 (*Peace, justice and strong institutions*) and SDG 17 (*Partnerships for the goals*) are connected to SDG 7.
- **General livelihood.** Gaining sustainable energy access will be based at least partly on renewable generation. This will avoid emissions from fossil-fuelled electricity sources like diesel generators, that could be prevalent without electrification plans and frameworks. It therefore plays into SDG 12 (*Responsible consumption and production*), SDG 13 (*Climate action*), SDG 14 (*Life below water*) and SDG 15 (*Life on land*).

A closer review of these interconnections is presented in [17, table 2]. A more detailed analysis of the impact of rural electrification on public welfare can be found in [18, 37ff]. With its far-reaching implications, electricity poverty can be a factor that helps individuals and societies to leave the poverty trap [17]: The vicious circle of electricity deprivation starts with worse education, health care and less work opportunities, which in turn result in poverty and thus a lack of means to pay for electricity access. Breaking this cycle is the goal of SDG 7.
While universal electricity access for every household is the goal of most policies, community members without the needed financial means can also co-benefit from power arriving in their communities by using community services, such as „schools, health centers, water-supply systems, and communication facilities“ [16, p. 3]. As such, electrification does not only provide communities with basic services of livelihood, but can, in turn, have numerous benefits for society as a whole.

2.1.3. Electricity access today

Worldwide, there are about 1 billion people lacking electricity access still today [4, p. 11]. This reflects a linear increase of the electricity access rate since 2000 from 77 % [19] to 86 % in 2016 [4]. Effectively, about 1.2 billion people gained access in that time period [4, p. 40].

Most people suffering electricity scarcity live in sub-Saharan Africa with about 47.5 % of the total number of affected people, followed by 24.5 % each in developing Asia and India, 1.9 % in Latin America and 1.5 % in the Middle East [20, p. 22]. Indeed, in sub-Saharan Africa, electrification rates were not able to keep up with population growth until 2014, effectively leaving more people without electricity access although the relative electrification rate is increasing [4, p. 40].
Rural areas are most affected with 84 % of the people lacking electricity [4, p. 40]. Even though the ratio of undersupplied people in rural and urban areas implies that electricity poverty is mainly a rural problem, it would be wrong to assume that electricity deprivation is not an issue in those urban areas: If the central grid lacks in infrastructure and is overused due to increasing demand, brownouts and blackouts can occur that can limit public welfare and business revenues in its own accord (see Section 2.4).

2.2. Electrification plans

To tackle the task to electrify their people, many countries have developed electrification plans that define an agenda for the following decades [2]. By now, most of these plans use the multi-track approach, considering multiple technology solutions for electrification and making use of their different capabilities. The decentralized track utilizes standalone systems and off-grid MG, while the centralized track focuses on central grid extension [2]. These paths are implemented in parallel and should increase the speed with which the electrification process strides forward. However, the interaction of both tracks of electrification as well as the interconnection process of MG and the central grid remain unclear in most electrification strategies [2]. Therefore, [2] states that „[w]ithout recommendations and policies for this interplay, there is a risk of decentralized systems being abandoned when the national grid becomes available, leading to a reluctance to invest in these“ (see Section 2.3.4).

Possible electrification plan phases. Sometimes, electrification plans are divided into multiple phases, concentrating on different electrification targets, e.g. the Cambodian target to reach electrification for 80 % of the villages until 2020 [21, p. 3].
As such, [11] develops a three-stage electrification plan for five Nigerian states leading to full access in 2030. In the first stage, consumers that are easiest and most profitable to reach are electrified with off-grid solutions, while the central grid's generation capacities are increased. The second stage scales-up the adaptation of off-grid systems, implements first grid extensions and interconnects first MGs to the central grid. The last stage provides electricity to the most rural and financially weak consumers while interconnecting the bulk of implemented MGs.

Forecasts of electrification. While multi-track electrification plans often aim to reach SDG 7 by 2030, [4] does not expect them to fulfill their promises. They estimate that under current electrification plans about half of the people will gain access through grid extension, while MG and other off-grid solutions each bring 25 % of the new connections [4, p. 49]. However, about 8 % of the world's population (674 mio. people) will be left without electricity even by 2030 [4, p. 48]. In its *Energy for All Case*, in which universal access is reached by 2030, MGs are even expected to bring electricity to 290 mio. people (43 % of new connections), while grid extension only extends to 185 mio. people [4, p. 53].

2.2.1. Centralized track

For the last decades, national grid extensions were the preferred electrification solutions that governments concentrated their limited resources on, as they promise to allow a high number of people unlimited access to electricity [9, p. 1], [4, p. 44]. Adapted from countries with a high population density, centralized electrification was used to electrify areas from the top-down and has developed into a paradigm [11], [22, 14f].
However, the centralized track may not be the best option for electrification at each location. In rural areas implementing a national grid extension can be overly costly, as the costs grow with the distance from generation centers and consumer dispersion [8, p. iv], [22, p. 16]. Dependent on voltage, terrain and also country, extension costs vary broadly between 6 to 23 kUSD/k [23, p. 16], [24, p. 5]. Revenues can be low in comparison to these investments, as low demand density and low ability to pay, both resulting from low population density, income and electricity demand, lead to a low consumption per customer [8, p. iv], [22, p. 16]. In the following, the terms *national grid* and *central grid* are used interchangeably, as it is assumed that a national grid does not have to be single nation-wide interconnected utility, but can be build up by multiple, self-sufficient, utility-sized electricity networks with centralized generation capacities.

2.2.2. Decentralized track

The decentralized electrification pathway utilizes a number of adaptable technological solutions meeting consumers demand locally:

- **Stand-alone diesel generators** have long been dominant off-grid electrification solutions with the
- advantages of dispatchability [25] and low up-front investment costs. Their fuel expenditures are, however, high and subject to fuel availability and price volatility.
- **Stand-alone batteries.** For low-energy services, households can charge a transportable battery at grid-connected or solar-powered charging stations [16, 8f].
- **Solar Home Systems.** Solar Home Systems (SHSs) are common for individual, off-grid electricity supply with comparably low demanded services. They consist of one or multiple solar panels, a battery for night time supply (either low-maintenance PV battery or modified automobile battery) and control unit [16, p. 9]. This control unit is responsible for managing solar generation, battery charge and appropriate discharge and load supply. They have a wide range of capacities, are modular and can therefore be installed and extended as needed.
- **Micro grids.** Local, off-grid electricity grids (MGs) providing a bulk of consumers play an important role for decentralized electrification as they can provide electricity at lower costs and higher reliability than stand-alone systems. They at least bridge the time until the central grid arrives, and are faster to implement than grid extension. There are MGs that draw their power solely from diesel generators, others utilize renewable sources. Hybrid MGs, that include fossil fuelled generation capacities as well as renewable sources, emerge as the cheapest option for many project locations [23, p. 18]

Diesel generators and SHS are the most common stand-alone solutions today [4, p. 41]. Decentralized solutions have increasing momentum due to favourably developing policies and markets [4, p. 56]. Solar Home Systems and especially MGs are receiving governmental attention and are addressed by multiple governmental institutions, especially through so-called Rural Electrification Agencies (REAs) (comp. [23, p. 82], [9, p. 19]).

2.2.3. Choosing the appropriate path and technology

A decision regarding the appropriate solution to electrify a certain location in the near future is based on a comparison of system's costs, service level provided, policies and a multitude of other factors [4, 34f]. For a very fist assessment, to consider a low number of factors is sufficient, including distance from the grid, economic welfare, population density and demand. Grid extensions are favoured for locations close to existing infrastructure, but also close to demand centers of high economic strength. At a certain distance from the grid MGs tend to be cheaper, and they supply promising centers of high demand density and sufficient economic strength. Standalone systems, for example SHS, are pushed to supply spatially distributed consumers farthest away from areas of high demand concentration [16, p. 6] [4, p. 41]. The costs of electricity increase with decreasing system size, resulting in comparably high prices per kWh in remote locations with low demand. These tendencies are visualized in Figure 2.1.

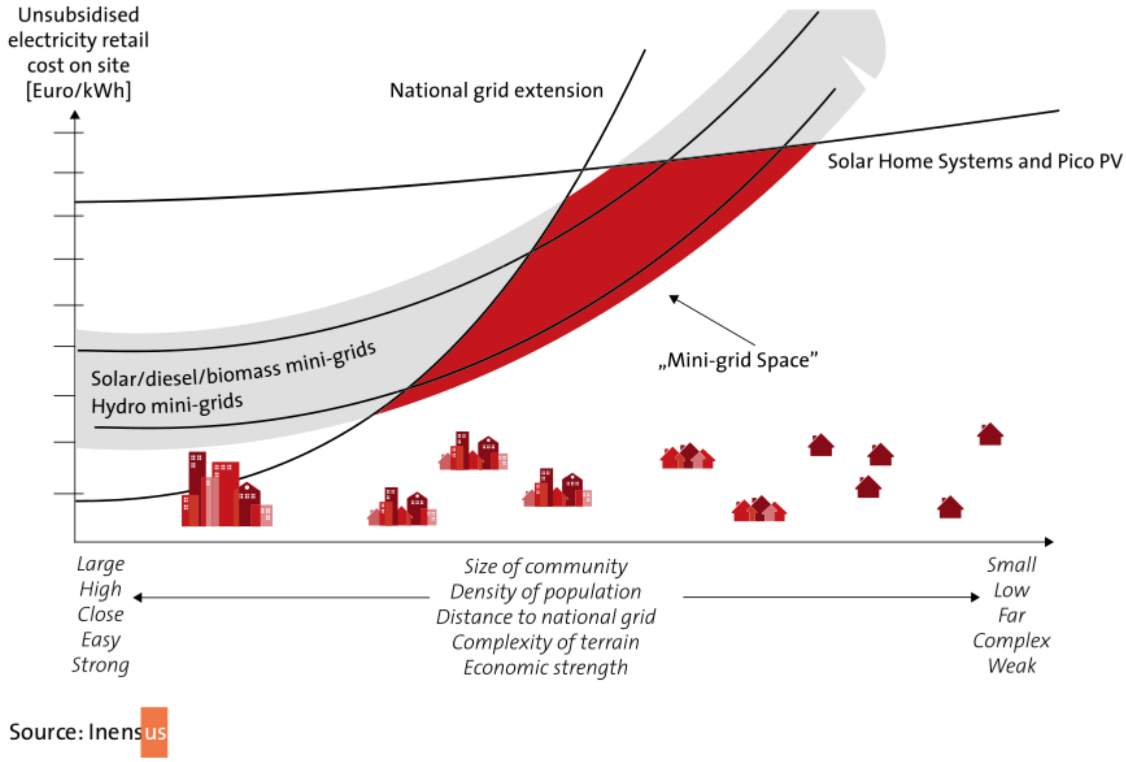


Figure 2.1.: *Applicability of electrification solutions (qualitative tendencies)*

Figure from [23], „Illustrating the "mini-grid space" (qualitative)", creator: Inensus

2.3. Micro grids for rural electrification

With neither a standardized architecture, nor a limit on its provided electricity services, MGs can range from small-scale electricity supply systems for just a number of households with a demand peak below 1 kW in Direct Current (DC) up to large-scale industrial sites or even cities, supplying several MW demand in Alternating Current (AC) [8]. Sometimes these local electricity grids are grouped by their peak, i.e. maximum, demand they are able to supply, number of consumers or their complexity. Possible categorizations, with decreasing capacities and capabilities, are *mini*, *micro*, *pico* and *nano grids*. However, neither MG architecture nor capacity distinction follow a universal definition [26, 8ff]. In the context of electrification, the term *mini grid* is also used [8, p. 52], [26]. In this thesis, the term *micro grid* is used for all local electricity grids.

Definition. In general, micro grid (MG)'s can be described as electricity supply systems with clear boundaries, self-sustainably able to provide local electricity demand with its local generation units. MGs can operate as stand-alone electricity systems (off-grid) as well as connected to a central grid (on-grid) [27]. Grid-connected MG can profit from services like cheap electricity consumption from the grid, possibly feed-in with profitable Feed-In Tariff (FIT) and stabilization during operation (see Section 2.3.3). The interconnection with a central grid is further described in Section 2.3.5.

Greenhouse Gas Emissions reduction in MG. In the past, local MG have been implemented as sole diesel-MG, resulting in a strong dependency on fuel availability and price changes. A hybridization with renewable sources, reducing the fuel consumption of a MG not only decreases Greenhouse Gas Emissions (GHG) emissions [25, p. 55], but often poses the least-cost supply option as well [28].
The implementation of off-grid MG, by generating and supplying electricity on-site, avoids transmission losses of the central grid, which can be considerably high [29]. This increases overall supply efficiency and therefore decreases GHG emissions of the electricity sector.

Future prospects. In 2015, about 54 % of the installed MG capacity was implemented in remote settings [30]. While standalone off-systems and micro grids only account for 6 % of the newly build connections [4, p. 10], their role is expected to increase in the coming decade [4, p. 45] (see Section 2.2). Decreasing technology costs, especially of solar panels [31, p. 1] and batteries [32, p. 10], encourage this trend. [4, p. 45] sees an increasing potential of MGs when these are built not only to supply residential loads but productive and commercial uses.

In the following sections, MG are be introduced in detail, including its components, design, stability, current drivers and barriers and its interconnection with a central grid. An introduction to MG gives [27], including a table summarizing its advantages and disadvantages. [28] outlines system sizing and [23] presents policies and business models.

2.3.1. Technological components of a micro grid

MG design is not limited by definition but always subject to specific project conditions and economic considerations [27]. As such, electricity supply of a MG can be provided through various component combinations. Most common MG components are diesel generators, PV panels and storage. Other electricity sources can be small-scale wind plants and hydropower [4, p. 40]. MGs can be connected to a central grid through transformer station. Additionally to generation and storage components, which are in focus of initial design optimization of a MG (see Section 2.3.2), the MG also consists of the distribution grid, electrical components and control units that should not be ignored.

Generators. Fossil-fuelled generators are central of the majority of MG, as they are cheaply available and dispatchable electricity supply units, i.e. they generate electricity when needed [25, p. 54]. They are often fuelled with diesel and have an efficiency that is dependent on their Load Factor (LF), which is the ratio of utilized and installed capacity. The generator efficiency increases with higher LF [33, p. 32]. As an estimate, diesel generator efficiency can be estimated with 30 to 35 % depending on LF [11, p. 98]. Diesel generators have a lower limit of generation, the minimal loading [28, 38f], which potentially leads to electricity losses when providing low demand.

Renewable power. While some renewable sources, mostly used in larger MG, like pumped hydro, run-off-river, biogas plants and heat pumps are dispatchable, i.e. can directly react to load changes, the most common technologies, photovoltaic (PV) panels and smaller wind plants, used in smaller MG, are non-dispatchable, i.e. generate power dependent on the natural variability of their renewable source. Both solar irradiation and wind potential are specific to each project location. They are seasonally variable but also experience short-term fluctuations. Their integration, especially for high renewable penetrations, can call for stronger control, demand management and generation flexibility of the system [34, p. 658] (see Section 2.3.3).
It is expected that PV-hybrid-MG will be the prevalent MG architecture in Asia and Sub-Saharan Africa [8, p. 48]. If installing a PV system, it should be considered that it faces about 10 % losses due to array mismatch, dirt and shading [35, p. 74]. Solar panels experience an efficiency loss, degradation, of 10 to 20 % over 25 years [36, p. 184].

Storage systems. Hybridization can call for energy storage systems to cover variabilities and times of low renewable generation and allow night loads to be supplied through solar generation. This way, high renewable penetrations can be reached [28, p. 16]. [32, 8f] describes flow, advanced lead-acid and lithium ion batteries for remote MGs and emphasizes, that they can also aid optimal dispatch and system stability. Standard system parameters and operational ranges of different battery types used in renewable systems can be found in [24]. To manage charge- and discharge and adhere to the operational ranges of the utilized battery, charge controllers are used. They protect the battery from reverse polarity, overvoltage and deep-discharge and monitor battery temperature [36, p. 184]. The costs connected to storage systems can make up a large share of total MG investment costs [25, p. 55].

Inverters and rectifiers. This thesis focuses on AC MG, and does not consider DC MG. As demand requires AC supply, inverters are needed to connect DC and AC component: While a generator's output is AC electricity [25, p. 54], PV panels and batteries supply DC electricity [27]. Inverters also play a role in MG control strategies [27].

Auxiliary services and balancing. Monitoring, possibly even remotely, is necessary to ensure that the MG operates within its voltage, frequency and power quality boundaries (see Section 2.3.3). Protection devices are needed to avoid over- and undervoltage, overcurrent, frequency increase or drop as well as grounding; some of these features might be built-in inverter functions [5, p. 91]. Depending on national standards, further protection devices might have to be installed.

Distribution grid. Planning the distribution grid, local conditions including population distribution and road-networks have to be considered. An appropriate grid topology, i.e. the way that centralized generation and storage is connected to the grid's consumers, has to be defined. A number of formations are possible, ranging from radial, tree and ring topology. They differ in their redundancy and can limit or assist the reliability of the grid [37, p. 57]. Cable electric loses are relative to line distance, as such the distribution grid line length should be minimized, also to save costs [37, p. 53].
To determine the network with the least costs, highest efficiency and other fulfilled requirements, tools based e.g. on Matlab and Excel are applied [5, p. 57].

Central grid interconnection. Connecting a MG to a central grid requires not only installing a transformer station with a grid-tied inverter (the Point of Common Coupling (PCC)) [38, p. 417]. It also requires both MG generation and distribution grid to adhere to national standards, both to ensure safe supply but also avoid stresses on the central grid infrastructure. For further information regarding MG interconnection, see Section 2.3.5.

2.3.2. Micro grid planning

MG have to be developed for each location specifically, as demand profile, willingness to pay, possible resources and investment options are be unique the each project site. Planning a MG starts off with a demand estimation and demand growth forecast, continuing with a general definition of its architecture (see Section 2.3.2), sizing of its components and a first economical evaluation. These aspects will be presented below.
Further steps of MG planning are not presented here, as they are specific to the implementation context. This includes the development of a business case taking into account stakeholders and MG ownership, operation and maintenance scheduling as well as possible licensing and the implementation process itself.

Demand estimation. Demand profiling is an essential part of MG planning. It is either performed in advance to identify the project site with the best economical prospects or is central in the first MG design loop. Demand profiling reaches from initial demand assessment (e.g. in form of field surveys, comp. [28, 23ff]) to utilization plans and randomization up

to an estimation of seasonality and future demand growth. Especially for smaller MG with a low number of consumers generating an appropriate aggregated demand profile as well as MG design itself can be challenging. MG with a high number of consumers can profit from the rule of large numbers.
For demand estimation, it can be helpful to group consumer by types, i.e. distribute them into residential, business or agricultural and low, medium and high demand profiles and define utilization patterns for each of these types (com. [39], [28, p. 28]). Typical loads in context of household electrification are lighting, cooling fans, telephone chargers, radio or TV and fridges [28, p. 63]. Load of productive users can include irrigation pumps, milling or wood/metal workshops [23, p. 63]. Sometimes, loads are classified into critical loads, a demand that should always be supplied (e.g. hospitals), and non-critical loads (e.g. residential customers), which can allow lower electricity quality or can be disconnected for a limited time in case load shedding is necessary to ensure stable MG operation [38, p. 417], [5, p. 189]. As a general rule, demand tends to peak in the early morning and evening for settlements with a high share of residential consumers, while a sufficient number of business consumers can shift the peak demand towards noon [29].

One of the challenges of MG design includes proper assessment of future demand growth. Demand growth is connected to population growth and interconnection rate, but can also take place when living conditions increase and new appliances are purchased. Also, during surveying, future possibilities and utilization patterns of electricity supply might not be clear to the potential customers of the MG project. Electrification can also increase the number of small-scale businesses, i.e. shops and handicraft shops and can attract people to settle in an electrified village [22, p. 27].
Systems that are undersized have difficulties to adequately supply consumer's demand, thus have reliability issues and potentially experience to higher component wear. This can demoralize consumers to pay and thus endanger necessary revenues [28, p. 18], [40, p. 8]. On the other hand oversized systems, especially those with a high renewable penetration and high initial investments, can prove less efficient and economically unviable [28, p. 17]. Modular system design can avoid these economical shortfalls.

Demand-Side Management (DSM). Influencing the demand profiles in a way that a more effective, profitable MG can be implemented is the intention of DSM. This can include decreasing the demand through the use of efficient appliances, e.g. LEDs, or shifting it from times of peak demand, e.g. evenings, towards off-peak hours [28, 40f], [40, 31f].
Tariffs can also be used to influence consumer behaviour. Setting a monthly flat-rate tariff per connection can encourage customers to increase demand, but can also lead to an overuse of commons. Setting a price per kWh discourages consumption and can potentially lead to low revenues. A compromise could be to charge consumers based on the services they use, i.e. per appliance. A short summary of possible tariff structures is presented in [23, 48ff].
If the load profile makes a MG with around-the-clock service infeasible, it should be considered to limit the grids operating hours, e.g. from 9 AM to 11 PM, thus minimizing losses as well as investments and achieving affordable tariffs [40, p. 31], [41, p. 163].

Design outlines. MG design when including higher shares of renewables requires dynamic planning tools (see Section 3.1), determining the projects's optimal system capacities. However, there are some rules of thumb that can help perform a first capacity estimation (comp. [42, p. 68], [28, p. 39]), for example to cross-check the results of blackbox software (see Section 3.1):

- The diesel generator can be sized after peak load, optionally with generation overhead
- For high renewable shares, battery size should at least equal the night load
- PV panels should generate enough electricity to cover day-time demand, or, for high renewable penetration, provide a large share of the daily demand

In general, MG in rural areas should be designed in a way that minimizes repair and maintenance [5, p. 190] as to avoid downtimes due far travel distances or unavailability of replacement components. Using cheap but low-quality components therefore does not necessarily lead to the intended low system costs, as sensitive components, e.g. the storage system, should be equipped with appropriate control devices to avoid unnecessary aging and replacement. Further guidelines are summarized in [5, p. 76].
To decrease system costs, it can be considered to allow certain amount of supply shortage [29]. One should, however, consider that a lowered reliability can lead to disappointed consumers.

2.3.3. Micro grid control and stability

A MG control unit overseeing MG operation has to perform a variety of tasks: Long-term dispatch algorithms cover load shedding, demand smoothing, shaving and shifting as well as demand and generation forecasting, system monitoring, fault management and islanding, i.e. disconnecting from the central grid in case case of outages within or outside of the MG. Short-term features include balancing and energy quality control, i.e. system stabilization [43, 9f], [27].
This electricity quality control is essential to reliable MG operation. It has to ensure, that and voltage and frequency are kept in its tight operational ranges. In many countries around the design values of a voltage of 230 V AC and a frequency 50 Hz [5, p. 89], [38, p. 418]. Deviating too much from this ranges can damage sensitive devices [44, p. 30].
Electrical disturbances of these parameters can incur in form of small-signal distortions, i.e. natural demand and volatile generation drops and swells as well as transients, e.g. heavy voltage drops induced by lightning.
Off-grid as well as islanded MG have to draw stability and guarantee sufficient power quality from its own installed capacities [43, p. 12]. They lack the inertia of larger grids [43], while at the same time renewable generation and demand have greater variability [27]. System stability can be drawn from diesel generators or storage [4, p. 2017], which can provide a „buffer to mitigate the impact of imbalances in electricity generation and demand“ [27].
Grid-tied MG can depend on the central grid. Due to high system inertia [43] this central grid - if reliable - rarely deviates from its operating conditions. Grid-tied MG therefore can draw frequency and voltage stability from the central grid [43, p. 12]. If the central grid itself, however, experiences disturbances, these are inherited by the grid-tied MG, if islanding is not be performed in time (see Section 2.4).

2.3.4. Drivers and barriers of micro grid adaptation

Cost reductions of MG components and technology advancements as well as new regulatory frameworks in many countries have encouraged MG planning [8, p. v]. Still, current MG adaptation rates are lower than necessary to fulfill set targets - only 6 % of new connections are implemented through both standalone and MG systems [4, p. 10], even though until 2030 MG are to bring 25 % [4, p. 49] or even 43 % [4, p. 53] of new connections. This can be attributed to a number of barriers that micro grids are facing during their planning process and operation. In the following, both barriers and possible drivers of MG implementation are presented. The section summarized reports on lessons learned and stakeholder interviews, including [45], [46] and [47].

Financing. As MG projects are capital-intensive, financing options are necessary. As such, it is very inhibiting that MG project planners are denied access to loans and can not find investors, as these perceive the risks of MG projects as overly high. External, possibly volatile factors, i.e. inflation, financial crisis, political instability or droughts, create an unfortunate business environment. To make MG projects more viable, the government could guarantee stability of the factors it can influence, i.e. taxation and subsidies. It is central to improve the accessibility of loans, for example by providing risk evaluation strategies for shareholders, so that these can rationalize this process and aMG attract loan-giving banks and investors.

Customer care. Customers should be central in MG operation, as their dissatisfaction, e.g. due to outages, can demoralize them to pay their bills on time and can endanger MGs. Their (dis-) satisfaction should be addresses and monitored, which could also help to identify faulty distribution grid infrastructure. Tariff schemes need to be appropriately designed to fit consumers needs and ability to pay.

Legal framework and subsidies. MG projects suffer from regulation and enforcement instability, which are essential to MG feasibility. Changing legislation, including retail tariffs or FITs can instantaneously make a business concept of an already implemented MG unviable. Subsidies for electricity provided through the central grid distorts the market and disadvantages off-grid technologies.
The government has multiple options to support MG implementation. Decreasing or exempting taxes on MG components and decreasing subsidies for utilities can level the playing field. Licensing and technical standards can avoid badly-planned MG to be implemented, might ensure compatibility with future grid arrival and also protects MG customers. Retail tariff regulation can protect consumers but, combined with subsidies to cover possible electricity generation cost margins, can also ensure revenues at otherwise unprofitable project sites. Feed-in tariffs can give an inventive for interconnection. Regulations should take into account long-term reliability, i.e. should provide guarantees for existing MG.

Standardization. With every MG being specifically designed to fit one project site, the project's development time and costs are high. Frameworks developed by stakeholders could ease the workload and enable fast MG deployment. Technology developments that could ease operation or increase efficiency should be implemented.

Project development. Some MG projects fail as their development has been cutting edges in system design to decrease costs, but instead led to premature implementation or inappropriately sized MG. Underestimating maintenance and untrained staff, resulting in increasing downtime, as well as overestimating future revenues can lead to MG operation becoming economically infeasible. The emergence of cheaper technology options or national grid arrival can threaten the tariffs of existing MGs.
Assessing the potential of project sites should therefore not be rushed but evaluated in-depth. Concentrating on clients with high demand can help MG to be viable. It is very important that staff is well-educated and able to run the MG reliably. Monitoring can help to ensure proper operation and to find faults. Both undersizing and employment of untrained staff can lead to outages, and, thus, to consumer dissatisfaction. Future supply reliability of possibly growing demand should be ensured.

Grid arrival. The prospect of grid arrival can stop MG projects in its tracks, and an unpredicted arrival often leads to abandonment and, thus, stranded assets. Electrification plans that include the time of grid arrival can help shareholders with the decision on whether or not to implement a project. It is also important to develop regulations and decision strategies regarding the options after MG interconnection, also including reimbursements or buyouts. Post-interconnection adaptations of the business model, e.g. redispatch of stranded assets through containerization, could also be an option.

Based on these findings, [4, p. 45] states that the full potential of MG could be activated with an „supportive enabling environment, the key elements of which are likely to include a clear central grid extension plan, a framework that regulates how to integrate mini-grids if or when the main grid arrives, and clear rules for setting tariffs". Countermeasures to most of the addressed issues above have been initiated. However, the perceived danger of grid extension continues to inhibit the implementation of otherwise suitable MG projects near to the national grid. This thesis therefore concentrates on the issue of interconnection.

2.3.5. Interconnection of micro grids to a central grid

Even though the perspective central grid interconnection has a damping effect on MG implementation, the technical aspects and business cases have not gone unnoticed in the research community. By now, MG interconnection and islanding has been standardized through IEEE 1547.5 [27]. A higher source of uncertainty is connected to the legal frameworks, including standards, tariffs and future operation options after interconnection.

Technical issues of interconnection. Most importantly, MG need to adhere to utility standards to be allowed to interconnect. This should be considered when implementing the off-grid MG's distribution grid, as in case of non-compliance the MG is technically not allowed to be interconnected with the central grid and would turn into stranded assets [4, p. 41], if no potentially costly refitting is executed.
The interconnection takes place by installing a transformer station as the PCC between central grid and MG. It includes a static switch, a circuit breaker, that manages on-grid and islanded operation and their transition [38, p. 417]. This transition is called *islanding* and

describes the process of intentionally disconnecting the MG from the central grid, e.g. if the central grid experiences an outage [8, p. 56], [9, p. 333]. If the central grid experiences many blackouts, it could be favourable not to connect to it thorough a synchronous AC inverter but trough an asynchronous connection (AC-DC-AC), as to avoid disturbances of the central grid to spread to the MG's electricity reliability or quality [27]. In case that the MG consumes and feeds into the central grid, the utility requires a metering system to be installed [8, p. 56]. Technical details regarding the design of MG for interconnection with a central grid are presented in [44].

Operation after interconnection. Interconnecting to an utility can change the operating conditions of the MG, last but not least as it now has access to potentially cheap central grid electricity. This can however also endanger MG operation, as the Levelized Costs of Electricity (LCOE) of a MG are higher than of supply from the central grid [4, p. 40].
[8] evaluated post-interconnection options, comparing experiences in Sri Lanka, Indonesia and Cambodia, where MG are mainly based on diesel generators or hydropower. Most MG in Sri Lanka and Indonesia terminated their operation after grid arrival with some transforming into small power producers (SPPs) and some in Indonesia operating in parallel to the central grid [8, xi ff]. In Cambodia, however, MG have met an enabling environment that was able to transform most of them into small power distributors (SPDs). Retail tariffs are uniform throughout the country and possible financing gaps are covered by subsidies, encouraging MG expansions even to areas of lower demand density. An important factor of the success were licensing processes ensuring the quality of distribution grids, but also that utilities see pre-existing MG infrastructure as an advantage [8, xi f].

Based on this evaluation, [8, p. x] defines a number of possible post-interconnection operation and business options of a previously off-grid MG. Amongst these are:

- The MG operator converts into a SPP, selling generated electricity to the new utility.
- The MG abandons local capacities and acts as a SPD, using its distribution grid to provide consumers with electricity from the central grid with an additional distribution margin.
- The MG is operated as a grid-connected MG, consuming from the central grid and feeding-in surplus generation e.g. from renewable sources. [8] defines these option as SPP&SPD.
- Operation of MG in parallel to the central grid without interconnection, e.g. feasible if central grid requires high connection costs per consumer or its supply is not reliable.
- Termination of operation including reimbursement or buy-out.
- Abandonment of MG operation and stranded assets.

While the need for regulatory frameworks at grid arrival has been met in a number of countries, including „Cambodia, India, Indonesia, Nepal, Nigeria, Rwanda, Sierra Leone, Sri Lanka and Tanzania“ [8, p. x], a framework to assess likely future operation and feasibility does not exist. Research into such a framework as well as interconnection options is still necessary [2].
[8, pp. 44, 48] points out the necessity to evaluate interconnection of PV-hybrid MG as well as their relocation at grid arrival.

2.4. Weak central grids

Even though central grids are the dominant electrification pathway (comp. Section 2.2), they do not always provide the expected supply reliability.

Brownouts and Blackouts. Many countries experience low-quality electricity supply as well as interrupted supply due to load shedding and outages [48, p. 116], [49, 26f]. Millions of people are connected to such unreliable electricity grids [29], [2] citing [14].
Events of electricity supply outages are called blackouts, while period of low-quality electricity supply, i.e. disturbances of voltage or frequency, are called brownouts. Both brown- and blackouts are detrimental to the operation of businesses, hospitals and schools, and can damage sensitive equipment [44, p. 6]. As such, unreliable supply can limit economic growth and is perceived as the major obstacle of businesses in about 30 % of developing countries (2016), resulting in revenue losses of up to 2 % of Gross Domestic Product (GDP) [4]. Power outage trends for every country are presented in [14].
Black- and brownouts occur in weak electricity supply infrastructure. [50], focusing on India, lists reasons for outages: They are often connected to preconditions, e.g. aged distribution and transmission systems and high grid and power plant utilization, i.e. low overhead to meet peaks. High transmission losses as well as planned and unplanned plant shut-downs are critical and diminish generation overhead further. In case of line breaks, outages can last a couple of days [29]. If multiple events, shutdowns or simultaneous interruptions, occur in parallel, it can lead not only to local brownouts or blackouts, but to region-wide and long lasting power grid shutdowns - as it has took place in July 2012 in India, were a 2 day long outage affected over 600 million people [50].

Mitigating grid unreliability. While mostly seen in rural context when grid extension is too expensive, the decentralized systems presented in Section 2.2.2 can increase reliability by providing backup in case of central grid outages [4, p. 34]. For individual consumers, two technical solutions to meet unreliability of supply are at hand. For lower electricity demand, a backup battery can bridge times of interrupted grid supply. The battery is charged through an inverter when electricity from the grid is available and discharged when an outage occurs. This can, for example, be observed in Uttar Pradesh, India **parikh_2014** Most commonly and also applicable for larger loads, a backup diesel generator is used, which is utilized when the grid experiences an outage [4, p. 83], [48, p. 116]. For communities, islanding MG can provide reliability despite central grid outages [4, p. 34]. [8, pp. ii, 6] calls these MG, that are installed due to unreliable central grid service, third generation micro grids.

Research gap addressed with this study. As presented previously, decentralized electrification through MG plays an important role to reach SDG 7. However, MG planners perceive grid arrival as a danger to their assets, leading to project locations near utility grids without supply. As MG interconnection has not been addressed sufficiently in research, this fear has not subsided. Even though many central grids lacking reliability, few studies take take into account the unreliability of central grids [2], [29]. [2] provides a comprehensive summary of studies evaluating the design of electricity solutions in connection with grid outages and describes different possibilities to simulate grid availability in Homer. The interconnection of

a specific PV-hybrid-MG to an unreliable central grid is evaluated by [2]. [32] is of the few studies describing experiences of the interconnection of diesel and hydro-powered MG to the respective national grid and finds that many cease operation. They remark the research effort necessary to identify potentials of PV-hybrid MG connection to an arriving central grid.
This study addresses the research gap and contributes to the issue. It evaluates a number of potential PV-hybrid MG project sites, predetermined through a previous study, and their potential after connection to a reliable and an unreliable central grid.

3. Methodology

This study assesses the interconnection of off-grid micro grids (MGs) with to an arriving national grid of high or low reliability. For that, it optimizes and simulated multiply energy systems. The methodological background is presented in this chapter. A short introduction to commonly used tools for MG design is presented in Section 3.1. The modeling framework applied in this research, the open-source Python is an open-source programming language (Python) library Open Energy Modelling Framework (oemof) is introduced in Section 3.2. The tool is presented in detail in Section 3.3. It is then applied to the case study described in the following Chapter 4.

3.1. Commonly used micro grid planning tools

Since the very first electricity grids emerged, for about a century [27], MG planning has been performed for various MG locations, sizes and architectures. With an increasing number of technologies the energy system's complexity increases, due to the intermittent nature of renewable generation as well as dynamic operating conditions of storage systems. This requires tools for MG simulation and sizing [51]. Numerous tools emerged that can aid project planners in designing MGs. [52] presents 75 simulation tools able to model energy systems with a high renewable penetration. They are based on a different programming languages, and they can be either open-, closed- or closed-and-paid-code. [53] describes a selection of commonly used solutions, including the most prominent MG design software Homer [54]. Homer is a closed-source and paid software solution with a graphical interface that allows the design of single MGs. It includes a component library, advanced component models and sensitivity analysis.

As many other solutions, especially those that are closed-source, it has limited modifiability and does not allow the analysis of a greater number of project sites. Closed-source tools are inherently intransparent regarding their underlying algorithms and can be viewed as blackbox applications, effectively making them unfit for scientific, verifiable research [53]. [53] therefore evaluates strategies to „open the blackbox of energy modelling“ and presents a number of open source tools. These provide transparency, ease reproducibility, reduce application barriers and can foster cross-sectional exchange [51].

With the specific requirements of the case study conducted in this thesis (see Section 3.3.1), none of the available tools can be applied to solve the research questions. Therefore, an new optimization and simulation tool is developed based on oemof.

3.2. Open Energy Modelling Framework

The Python-based Open Energy Modelling Framework (oemof) offers an accessible library to create various energy system models based on a couple of basic components. Energy systems modelled by oemof are not limited in scope but rather can range from analysing smallest systems like Solar Home System (SHS) to country-wide models of electricity networks. Each model created with oemof can consist of sinks, sources, transformers and storage, all connected through uni-lateral connectors with respective busses.
Oemof has been subject to a couple of publications, of which a few are summarized here. [55] gives a general introduction to its capabilities. [53] compared the framework to other energy system simulation tools. [51] describes micrOgridS, an MG optimization tool based on an unofficial oemof version, and compares its performance with Homer. It finds that oemof results in lower capacities. The tool presented in Section 3.3 builds up on the experience gathered in the latter paper, but sets a greater focus on adaptability and usability.

Building and optimizing energy systems. When building an energy system model with oemof, the system in question has to be defined as a combination of sinks, sources, transformers and storage. They are connected via uni-lateral flows through one or multiple busses. Each component has a number of parameters describing its behaviour and costs are assigned to flows from or to the respective component.
Further information and additional components integrated in oemof can be found in its documentation [56]. Additional constraints, i.e. a minimal renewable share criteria, can be added to the oemof model.
The model is transposed through oemof and Pyomo is a library for python (Pyomo) to a set of linear equations describing flows and related costs. The problem can then be optimized utilizing different solvers, e.g. Gurobi and Cplex. The hereinafter described, programmed and utilized tool was tested for the recommended Coin-or Branch and Cut Solver (cbc solver). The solver minimizes the objective value, in this case, the total system costs for investments and operation. This results in the cost-optimal solution of capacities and dispatch. For that, each bus is balanced out for each time step in the analysed time period.

Built-in limitations of oemof. Oemof has some built-in limitations resulting from its nature of a linear optimization framework: The core of oemof is to model and solve linear optimization problems. Real component behaviour however is often not linear, i.e. charge efficiency is dependent on the State of Charge (SOC) of the battery and diesel generator efficiency is dependent on its current Load Factor (LF). While the assumption of constant efficiencies is a valid simplification for a quick and approximate simulation of an energy system, it also introduces deviations from actual system behaviour.
Some of the simplifications needed for linearization can be met or even avoided with Mixed-Integer Linear Programming (MILP) (comp. also [57]). A build-in example in oemof poses the transformer: As long as its capacity is defined, a transformer is allowed to have a minimal and maximal LF, amongst others implemented through boolean state variables (integers). Another example is the off-set transformer proposed in [51], which enables a linear dependency of fuel consumption based on its LF and thus allows to model variable generator efficiency with a linearization.

When including MILP into an oemof model however, one has to be aware that it can result in local minima being confused for a global minima, i.e. deviate from the global optimal result, and that it can hugely increase optimization time or even lead to a termination during the solving process.
Oemof optimizes the capacities' dispatch to a degree not possible during actual operation: The simulation is based on perfect foresight, i.e. it optimizes all time steps of the linear equation system at once. Therefore, no uncertainty is connected to future demand or generation from renewable sources and as a result, the dispatch of capacities is overly optimized and unrealistic to reach during actual operation: Batteries, for example, would charge and discharge according to perfectly forecasted future irradiation and demand. The optimized capacities, dispatch strategy and in turn system costs or Levelized Costs of Electricity (LCOE) therefore can be underestimating actual values.
With these two major limitations, a system design resulting from a linear optimization problem should not be understood as an actual implementable design. However, it can allow a first assessment and a comparison between different scenarios or project sites.

3.3. An open-source tool for micro grid optimization

While there are MG planning solutions available, they do not meet the requirements of this research's case study. To enable knowledge transfer and ensure free and open science, a MG optimization tool utilizing the oemof, based on Python3, was created. By using an open-source software, it will be possible to modify the code according to future users' needs, including academia and industry. Due to its interface and coding structure, the developed tool can not only be applied to optimize MG systems but various on- or off-grid electricity solutions. It finds the optimal system capacities, their optimal dispatch and evaluates the system's performance and costs. The program's features, structure, used input data and underlying component models are presented in the following sections.

3.3.1. Requirements

For the development of this study's tool, stakeholder requirements were taken into account, as [51] defined a number of desired features and their prioritization for a MG simulation tool based on a workshop organized by the Reiner Lemoine Institut (RLI). The optimization of basic MG components has the highest priority, including components that could be strongly pre-defined like solar energy source, lead-acid and lithium ion batteries or a generic energy source or storage. It should be possible to define multiple diesel generators, Alternating Current (AC) and Direct Current (DC) coupling are desired and inverters should be a part of the system. With less priority, further energy source and storage technologies could be included. Allowing a grid interconnection is of medium priority for the stakeholders.
To answer the research questions addressed by this study, certain requirements towards the simulation emerged: To evaluate the influence of national grid outages on MG design and performance, the tool must be able to model grid interconnection and emulate randomized blackouts. Additionally, the tool has to be able to evaluate batches of potential project sites and perform a sensitivity analysis of different parameters.

Based on the stakeholder and case study's requirements, the simulation tool was developed and coded as a Python tool utilizing oemof [10]. Sector-coupling is not included in the tool. While the code of the simulation tool is not presented here, its component models, features and general structure are explained, also for future prospective users, in the following sections.

3.3.2. Implemented features

The programming process focused on a versatile and adaptable tool structure, enabling future MG planners to modify the simulated energy system to their specific project requirements or research questions. As such, following features were introduced:

- **Versatile application and scenario definition.** Through scenario definitions, a multitude of energy system models (cases) can be defined. The energy system model's capacity and their dispatch are optimized. All energy systems can be simulated that can be reduced to a combination of the following components: AC and/or DC demand, generator, photovoltaic (PV) panels, storage, inverters, rectifiers, wind plant and connection to a national grid.
- **User-friendly interface.** All simulation parameters, project locations and scenarios can be defined within a single excel file. The time series connected to one or multiple project locations can be defined in one or multiple .csv file(s). Even though it is necessary to install Python as well as required packages and execute the tool via a command-line interface (e.g. miniconda), this should enable users without programming experience to use the tool without having to edit any of the provided code.
- **Multitude of input parameters, sensitivity analysis.** Numerous parameters can be defined to characterize the electricity solution to be simulated, including many techno-economical parameters. A sensitivity analysis of any parameter can evaluate its influence on the overall optimization results. The simulation can run for any time period between one day and a year with hourly time steps.
- **Multiple project sites.** Multiple locations with specific time series, e.g. AC or DC demand, renewable generation and grid availability can be defined in the excel template. A location-specific definition of input parameters is possible.
- **Restarting simulations.** Oemof results as well as generated grid availability time series can be saved and used to restart simulations, e.g. if a simulation aborts. This can, especially during a multi-parameter sensitivity analysis, save computing time.
- **Automatically generated graphs.** To visualize the dispatch of the optimized components, it is possible to generate and save graphs displaying the storage's charging process and more importantly the electricity flows, SOC and grid availability of the system. They can be saved as .png files displaying the whole analyzed time period as well as five exemplary days and as time series in .csv files.
- **Output of linear equation system.** Advanced users can save the linear equation system generated through oemof, e.g. to check its validity or solve the equation system with other solvers suitable for Pyomo.
- **Additional constraints.** To ensure technological reliability of the system, a static stability constraint can be applied. A minimal renewable share can also be required.

3.3.3. Simulation tool outline

The developed simulation tool can roughly be divided into five modules: Data collection, data processing, blackout randomization, oemof-aided building and optimization of an energy system model and evaluation. The process is visualized in Figure 3.1.

Data collection. All necessary data is provided or linked within an excel template. Settings, modelled energy systems, techno-economical parameters as well as a number of project sites or sensitivity analysis can be defined here. A list of all parameters that can be provided can be found in Table A.2. For each project site the path to its time series, provided as a csv-file, is linked. It can contain DC or AC demand (kW), specific solar generation (kW/kW$_{p,inst}$), specific wind plant generation (kW/kW$_{inst}$) and a boolean time series indicating grid availability.

Data processing. When starting the tool, all input data is loaded. The data is initialized for each of the project sites and all experiments of the sensitivity analysis are automatically generated. The time series are cut down to the actual evaluated interval length. Specific per-unit present-day costs and annuities for each component, including capital expenditures (CAPEXs) and operational expenditures (OPEXs) occurring over the whole project duration, are calculated.

Blackout randomization. While actual blackout time series require local measurements of e.g. voltage, information on average blackout duration (in hrs) and frequency (per month) are easily available in [14]. Therefore, these values are used in the simulation tool to artificially generate randomized blackout time series. To take into account the volatility of blackouts, they will be introduced as distributed events, in which the average blackout frequency and duration equals the average of the Gaussian distribution with defined standard deviation. First, the number, start times and durations of the blackout events are randomized. From that, a boolean availability vector is created. Each start time is assigned a blackout duration. Blackout events are allowed to overlap, resulting in a deviation from the initially defined average number and duration of blackouts. The blackout time series can be saved to a file and thus be re-used when running other scenarios that should be based on the same conditions.

Building and optimizing the energy system model. Successively, each of the sensitivity analysis' experiments are optimized and evaluated based on each of the cases defined in the excel template. A case can be based on a previous case, i.e. when evaluating how a MG optimized for off-grid operation performs after grid-interconnection, the component capacities can be defined through a a previous simulation.
With the initialized case definitions, it is possible to generate the oemof energy system model from the available components (see Section 3.3.4) and constraints (see Section 3.3.5). With its adaptability, the tool not only allows to simulate MG but also other configurations, e.g. backup batteries. The generated model is translated into a set of linear equations and solved with the cbc solver. The optimization results can be saved and used to restart a simulation.

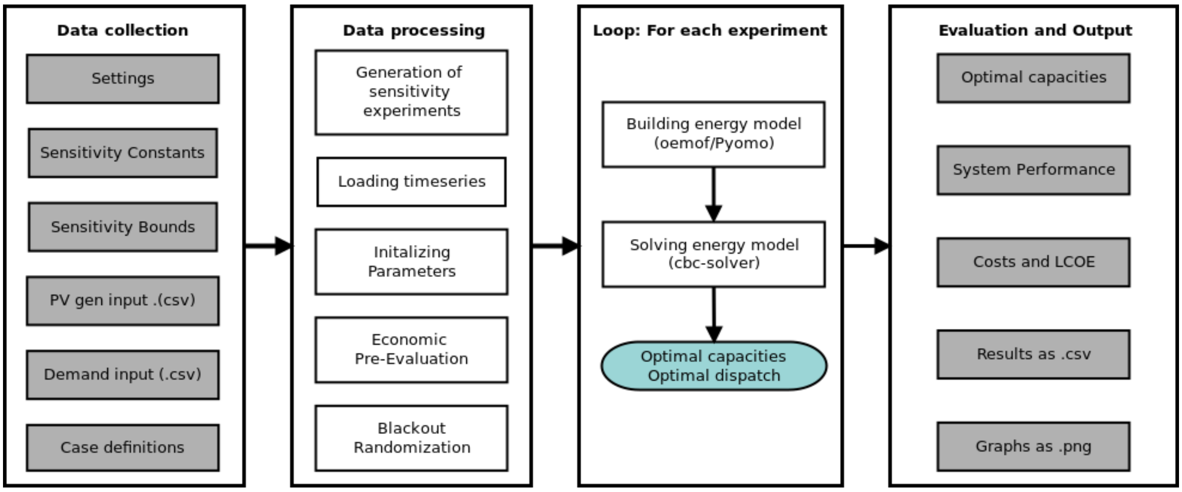


Figure 3.1.: *Simulation tool outline*

Evaluation. The optimized capacities of the energy system's components as well as their dispatch are extracted from the results. The dispatch time series can automatically be visualized and are used to calculate the system's technological performance, including reliability, renewable share and autonomy (see Section 3.3.6). Both optimized capacities and dispatch are used to evaluate LCOE and net present value (NPV) of the system, calculated as described in Section 3.3.7. When optimizing over a short time span, the cost are scaled to a year to adequately reflect the system costs. All performance indicators are calculated for the base year alone: Demand growth is not considered and costs are based on the base year and do not change over time, i.e. no learning curve decreases component prices of replacements. The output saved can be defined through the simulation settings and can consist of all parameter listed in Table A.3.

3.3.4. Energy system and component models

To model and optimize energy systems, and specifically MG's, an AC- as well as DC-bus with a multitude of components are integrated in the tool. A visualization of the tool's structure can be found in Figure 3.2. The components and their technological parameters shall be presented in the proceeding paragraphs.
Connected to the DC-bus are the following components:

- **PV plant**, modelled based on a feed-in time series in kWh/kW$_{p,inst}$. The installed capacity in kW$_p$ can be optimized. Efficiency and system losses are not parameters of the simulation, but rather have to be included in the provided time series.
- **Battery storage**, modeled with a constant throughput-efficiency, maximum charge- and discharge per
- time step defined through attributed C-rates, as well as minimal and maximal SOC. The installed capacity (kWh) and power output (kW) can be optimized.
- **DC demand** as a time series in kWh.
- **Excess** and **shortage** sink required due to oemof-terminology.

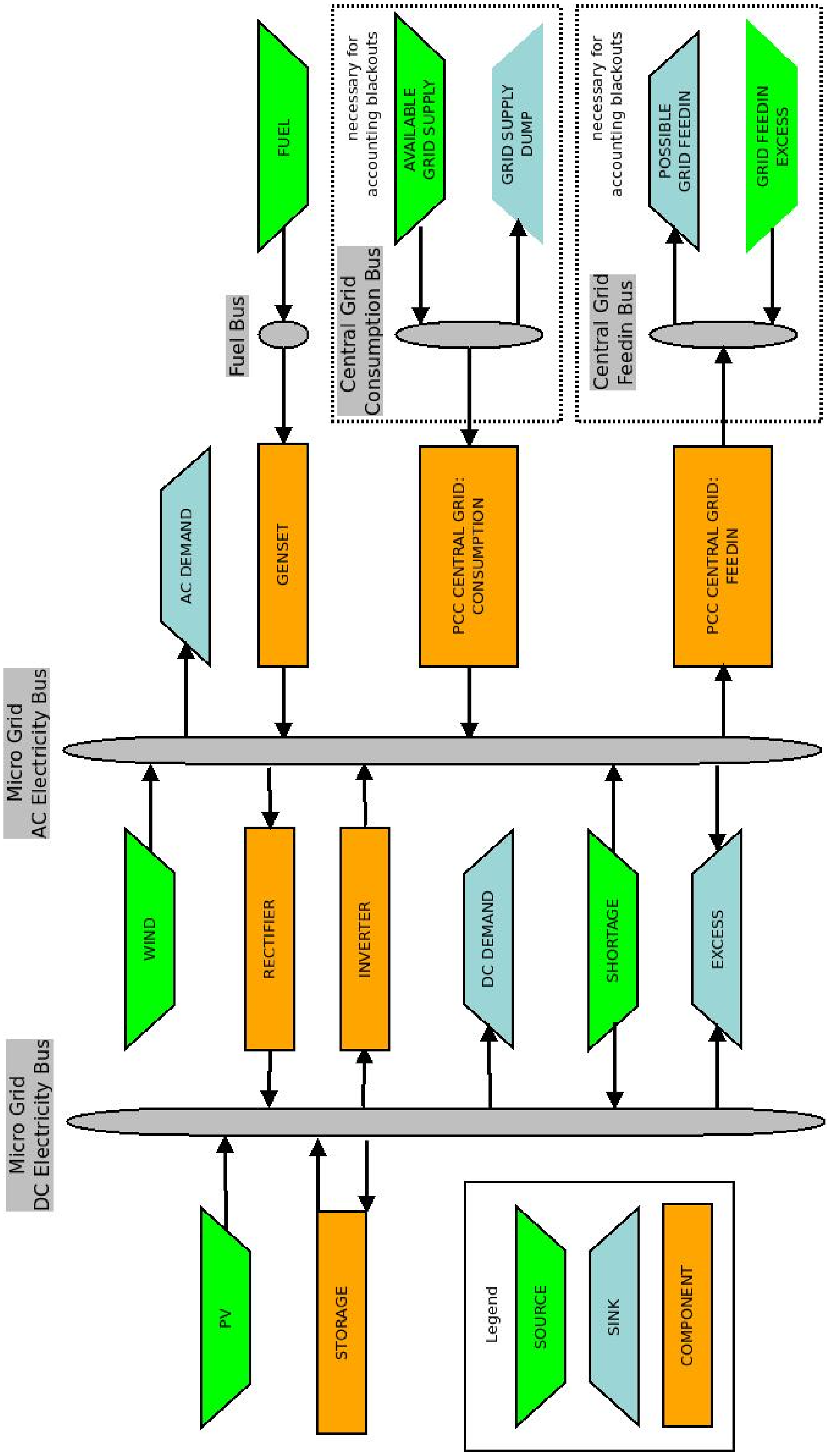


Figure 3.2.: *Adaptable energy system model of the simulation tool*

Using the Open Energy Modelling Framework. Each component can be excluded.

Through a **rectifier** and **inverter** with defined conversion efficiency, the DC- bus is connected to an AC-bus with following components:

- **Wind plant**, modelled based on a feed-in time series in kWh/kW$_{inst}$. The installed capacity kW can be optimized.
- **Generator**, modelled with a constant efficiency and with or without minimal loading. The generator type is determined by the combustion value of the used fuel. The installed capacity in kW can be optimized. The capacity of a generator with minimal loading can not be optimized. Fuel usage is detected trough a fuel source.
- **Point of Common Coupling**, enabling consumption from and/or feed-in to central grid. The installed capacity in kW can be optimized. Costs can either be attributed to the grid operator or the utility grid operator. The Point of Common Coupling (PCC) can allow an electricity flow only when the grid is available. This is defined through a Boolean time series, in which *1* indicates grid availability and *0* an outage.
- **AC demand** as a time series in kWh.
- **Excess** and **shortage** sink required due to oemof-terminology.

It is possible to optimize the dispatch of fixed capacities or to determine the optimal capacities of an energy system with or without connection to a central grid. It is not possible to directly define the used component capacities, apart from the diesel generator and the PCC, both of which can be sized based on a ratio of peak demand.

3.3.5. Additionally introduced constraints

Two constraints are introduced to guarantee technical variability of the optimized system as well as low Greenhouse Gas Emissions (GHG) emissions if a minimal renewable factor is defined.

Stability constraint. As off-grid MGs and grid-connected MGs that islanded due to national grid outage need to ensure stable operation (comp. 2.3.2), a stability constraint is introduced to the simulation tool. They ensure that a certain share of the demand (subtracted by shortage for balancing reasons), the stability limit L_s, is always either met directly through actual supply by the diesel generator P_{DG}, central grid consumption $P_{CG,feedin}$ or is available through potential battery discharge. This translates in two constraints focusing on stored electricity and maximal discharge power of the battery.
The **energy reserve constraint** requires a certain amount of electricity available for discharge through the battery. It can be defined through the current SOC, total battery capacity $CAP_{storage,kWh}$ and minimal battery charge SOC_{min}, but also limited by the allowed discharge rate $Crate$ and discharge ($\eta_{discharge}$) as well as inverter (η_{inv}) efficiencies.

$$\begin{aligned} P_{DG}(t) + P_{pcc,cons} + (SOC(t) - SOC_{min}) \cdot CAP_{storage,kWh} \cdot Crate \cdot \eta_{discharge} \cdot \eta_{inv} \\ >= L_s \cdot (P_D(t) - P_{short}(t)) \quad \forall t \end{aligned} \tag{3.1}$$

Additionally, the optimized discharge power $CAP_{storage,kW}$ has adhere to following **power reserve constraint**:

$$P_{DG}(t) + P_{pcc,cons} + CAP_{storage,kW} \cdot \eta_{inv} >= L_s \cdot (P_D(t) - P_{short}(t)) \quad \forall t \tag{3.2}$$

This constraint is to ensures that renewable generation or demand fluctuations can be met with frequency stabilization measures within the MG. For that, either a diesel generator or a consumption from the national grid through a transformer station can provide spinning reserve. Both are assumed to have a slower reaction time and need to actively contribute to stabilize the system, while batteries only need to have the potential to be sufficiently discharged as they react instantaneously to load changes depending on the control strategy in place. Possible stability-inducing effects of wind-plants are not taken into account.
The constraints are comparable to the spinning reserve constraint defined for the simulation tool used in the research study *Nigeria Rural Electrification Plans* in the scope of the *Nigerian Energy Support Programme* (NESP study) [58] with a stability factor of 20 %. [57] introduces an advanced or spinning reserve constraint based on MILP, requiring generator generation and battery discharge to be able to level out demand and PV variabilities of 25 % each (see [57], equation 7).
The stability constraint should be used when optimizing capacities and dispatch of MG, but is not necessary (or even applicable) when simulating SHS and e.g. the performance of the national grid itself.

Renewable constraint. For future use, it is possible to force MG optimization to determine the capacities that result in a certain minimal renewable share ($L_{res,min}$). It is reversely defined based on the total fossil-fuelled supply, and takes into account that a fraction of the national grid supply might come from renewable sources (RES_{CG}).

$$1 - \frac{\sum_t E_{DG} + (1 - RES_{CG}) \cdot E_{CG,cons}}{E_{gen,total}} >= L_{RES,min} \tag{3.3}$$

3.3.6. Calculation of technical performance indicators

Three main values are used to evaluate and compare the performance of a simulated energy system namely supply reliability as well as renewable and autonomy factor.

- **Supply reliability** η**.** Share of annual supplied electricity E_{spl} and electricity demand E_{dem} of the energy system analysed:

$$\eta = \frac{E_{spl}}{E_{dem}} \tag{3.4}$$

- **Renewable factor** RES**.** Ratio of electricity from renewable sources E_{RE} and fossil-fuelled sources E_{fossil}. The renewable factor of the national grid supply is taken into account.

$$RES = 1 - \frac{E_{fossil}}{E_{fossil} + E_{RE}} = 1 - \frac{E_{gen,DG} + (1 - RES_{CG}) \cdot E_{spl,CG}}{E_{gen,DG} + E_{gen,PV} + E_{gen,Wind} + E_{spl,CG}} \tag{3.5}$$

- **Autonomy factor AF.** Autonomy of an energy system from central grid electricity supply is measured as a ratio of the demand supplied from electricity generated within the MG $E_{spl,MG}$ and the total supplied demand E_{spl}. $E_{spl,MG}$ is calculated by subtracting the consumption from the central grid $E_{spl,CG}$:

$$AF = \frac{E_{spl,MG}}{E_{spl}} = \frac{E_{spl} - E_{spl,CG}}{E_{spl}} \tag{3.6}$$

3.3.7. Calculation of economic performance indicators

The annuity method is used to calculate the economical performance indicators of the evaluated systems (comp. [59, 229ff], [60, 31f]). The evaluation and comparison of the systems can be based on the system's net present value (NPV) and Levelized Costs of Electricity (LCOE). The equations necessary to calculate this parameters are explained below.
There are a number of project specific financial factors:

- Project duration T in years
- Weighted Average Cost of Capital (WACC) $wacc$
- Import tax tax
- Fixed project C_{proj} and distribution grid costs C_{dist}

As described previously, each component is defined through a number of technical as well as economical parameters:

- Investment costs per unit, without import tax c
- Operation and Management (O&M) costs per unit per year $opex$
- Utilization costs per kWh $opex_{wear}$
- Lifetime t

Component costs are central parameters of the optimization problem. As the simulation tool requires per-unit annuities for each component to built the oemof model, the costs have to be preprocessed. From the optimization results, NPV and LCOE can be calculated.

Pre-processing of financial data for optimization problem. Some of the economical values provided to the tool need preprocessing. The first-time investment cost $c_{1st,i}$ of component i is calculated with:

$$c_{1st,i} = c_i \cdot (1 + tax) \tag{3.7}$$

Due to their limited lifetime, k_i replacements are necessary.

$$k_i = round(\frac{T}{t_i} + 0.5) \tag{3.8}$$

Replacements have to be installed in year n within the project lifetime. At the end of the project life, the component has a residual value $c_{res,i}$. It is calculated with the discounted investment costs of the last replacement $c_{last,i}$ and assumed linear depreciation over the asset's lifetime (comp. [59, p. 133]).

$$c_{last,i} = \frac{c_{1st,i}}{(1+wacc)^{(k_i-1)\cdot t_i}} \tag{3.9}$$

$$c_{res,i} = \frac{c_{last,i}}{t_i} \cdot (k_i \cdot t_i - T) \tag{3.10}$$

The CAPEX of the per-unit costs for each component $capex_i$ can thus be calculated with:

$$capex_i = c_i + \sum_k \frac{c_i}{(1+d)^n} - \frac{c_{res,i}}{(1+d)^T} \tag{3.11}$$

The oemof model however uses the annuity of the net present costs of each component. For that the capital recovery factor CRF is introduced, which distributes the present values of the investment costs into annuities for each project year. The inverse of the CRF, the annuity factor a, performs the opposite.

$$CRF = \frac{d \cdot (1+d)^T}{(1+d)^T - 1} \tag{3.12}$$

The annual costs of each component a_i also take into account O&M costs $opex$ per unit and year, but not the specific costs related to component utilization per kWh.

$$a_i = capex_i \cdot CRF + opex_i \tag{3.13}$$

These per-unit annuities for each component as well as their utilization costs per kWh are fed into the oemof model, resulting in optimized capacities and energy flows. If the analysed time period does not span a year, the equivalent fraction of the costs are used. After optimization, this scaling is reversed, so that the resulting costs represent the system's cost over the whole project lifetime.

net present value (NPV) of the optimized system. The optimization problem results in optimized capacities as well as the energy flows E connected to each component. With this information, the component-specific annuities A_i including the utilization costs per kWh $opex_{i,wear}$ can be calculated with

$$A_i = a_i \cdot CAP_i + \sum E \cdot opex_{i,wear} \tag{3.14}$$

Annual cash flows CF are expenditures and revenues linked to different energy flows. They include expenditures for fuel CF_{fuel}, consumption from the central grid $CF_{CG,spl}$ and shortage penalties CF_{short} as well as revenues due to central grid feed-in from the MG $CF_{CG,feedin}$. Their per-unit-value is defined through fuel price, electricity price, shortage penalty costs and

Feed-In Tariff (FIT). Their cash flow in the first year is calculated with their unit-value p_i and accumulated energy flow of volume q_i:

$$CF_i = p_i \cdot q_i \tag{3.15}$$

The net present value of the whole project also includes fixed project, distribution grid and, optionally, central grid extension costs:

$$NPV = \sum_i \frac{A_i}{CRF} + \sum_i \frac{CF_i}{CRF} + NPV_{proj} + NPV_{distr} + NPV_{ext} \tag{3.16}$$

Levelized Costs of Electricity (LCOE). The second economic indicator are the well-known and used LCOE. To reflect the costs of the actual electricity supply, the total system annuity is related to the annual electricity supply. This implies a interdependence between system reliability factor and LCOE, but avoids that unreliable systems are assigned an unreasonable low LCOE solely based on their high intended - but unserved - demand.

$$LCOE = \frac{\sum_i A_i + \sum_i CF_i}{E_{spl}} = \frac{NPV \cdot CRF}{E_{spl}} \tag{3.17}$$

4. Case study

The above described simulation tool, which is based on the Open Energy Modelling Framework (oemof), is applied to a case study to validate the tool and analyse the prospects of micro grids interconnecting with a central grid. The case study is based on a previous project of the Reiner Lemoine Institut (RLI), the research study *Nigeria Rural Electrification Plans* in the scope of the *Nigerian Energy Support Programme* (NESP study), which drafted electrification plans for the five Nigerian states Cross River, Niger, Ogun, Plateau and Sokoto. This study only focuses on the state with the least electrification rate, Plateau. The electrification plans were developed through, Geographic Information System (GIS) analysis for cluster identification, demand profile estimation, grid extension planning, techno-economical cost estimations of Solar Home System (SHS), micro grid (MG) and national grid extension for each of the clusters as well as a prioritization of the electrification solutions. It resulted in a three-staged electrification plan for each of the states. The research object, methodology and results of the joined project are presented Section 4.1 and Section 4.2. Both chapters are largely based on the dissertation by Catharina Cader [11]. The input parameters based on the proceeding study as well as necessary simplifications and assumptions for this study's case study are presented in Section 4.3. The scenarios developed to answer the research questions listed in the introduction are introduced in Section 4.4.

4.1. General information on Nigeria

Nigeria is a sub-Saharan country with a population of around 191 million people (2017) [19] and a Gross Domestic Product (GDP) of about 376 billion USD (2017) [19]. Nigeria's per capita GDP had been increasing in the last decades but currently faces a three-year-long recession, leading to a GDP of about 2,000 USD per capita (2017) [19]. As such, the World Bank defines Nigeria as a lower-middle income economy since 2008 [61], revealing that Nigeria's economy still has room to develop.
The country is divided into 36 autonomous states [62], covering an area twice as large as Germany and spanning different climatic zones [11, 48, 65ff]. Renewable energy sources are abundant, especially concerning solar irradiation. It reaches especially high values in the north and the Global Horizontal Irradiation (GHI) varies nation-wide between 1.5 and 2.2 kWh/m^2. Nigeria's solar potential therefore exceeds the potential of Germany by far (1.0 and 1.2 kWh/m^2) ([11, p. 49] citing [63]). While Nigeria currently does not make much use of this potential, the government's objective is to increase the photovoltaic (PV) off-grid capacity to 13 GW until 2030 [64]. Wind power potential is limited due to generally low wind speeds with only few exceptions [65]. Hydropower stations have long been part of the existing utility grid infrastructure, but their share of the nations electricity generation decreased from more than 80 % in the 70's to 18.2 % in 2015 [19].

The national power grid infrastructure is often old [66] - transmission and distribution losses have decreased in the last decade, but still amount to about 16 % of the output (2014). [19]. The installed generation capacity of the national grid only amounts to 6 GW nationwide [11, p. 57], a capacity that is not sufficient to power the people and leads to frequent outages. New connections and increasing demand put further stress on the infrastructure and lead to an uprise of outages, as recent developments have shown: From 2007 to 2014 the number of outages has increased from 25.2 to 32.8 per month, while at the same time their duration increased from 8.2 to 11.6 hrs on average [14]. This issue can be expected to worsen if countermeasures are not taken in due time, especially regarding current population projections: Nigeria's population is expected to double until 2050 to about 410 million people [67, p. 26] and this high number of future needed connections combines with an electricity demand per capita that is likely to increase.
The lack of electricity access in Nigeria is predominant with a nation wide electrification rate of 61 % (2016) [4], amounting to 74 million people without electricity access. As in other countries, there exists a huge gap between urban (86 %) and rural (34 %) electricity access rates [4, p. 115]. Unreliable electricity supply results in 80 % of the consumers connected to the national grid to invest into a backup supply system [4, p. 83]. As a result, about 26 % of households (2011) ([11, p. 59] citing [68]) as well as 71 % of companies (2017) [14] own of diesel generators.
The inability of governmental institutions to meet their citizens energy demand has led to resignation throughout the country [11, p. 61]. An unmistakable sign of this resignation pose the paraphrases of the National Electric Power Authority (of Nigeria) (NEPA) as „Never Expect Power Always“ [69] and the proceeding institution, the Power Holding Company of Nigeria (PHCN), as „Please Hold a Candle Now“ [70]. PHCN was privatized in 2013 and its services unbundled. Transmission including trading is subject of the Transmission Company of Nigeria (TCN), distribution is operated through multiple distribution companys (DisCos) and electricity generation stands for itself [11, 60f].
But Nigeria's government has taken decisive measures to meet the peoples energy demand and, thus, Sustainable Development Goal (SDG) 7 in the last years. Measures to reach the target of 100 % electricity access until 2030 [4, p. 77] include a framework for feed-in tariff regulation in 2015 [71] as well as mini-grids in 2016 [72], both drafted by the Nigerian Electricity Regulatory Commission (NERC). They also included public-private partnerships (PPPs) and power purchase agreements (PPAs) in their toolbox [11, p. 62]. The Multi Year Tariff Order (MYTO) regulates distribution, end-user, transmission and generation tariffs and their development between 2015 and 2024 [73].

4.2. The NESP study

As the data acquired from the NESP study is used as input data for the following case study evaluation, the methodology as well as results of the research project are presented in the following paragraphs. The subsequent section is largely based on [11] and [74].

Identification of settlements and their current electrification status. GIS analysis is used to process satellite imagery on land use and derive a population raster data set, identifying settlement clusters in each of the studied states [11, 80ff]. These clusters are then processed to identify currently non-electrified settlements that have to be included in electrification planning. The electrification status is derived from satellite imagery on night light emissions, data sets on public infrastructure (schools, hospitals, governmental buildings) and power grid infrastructure. As grid connection is the prevalent electrification type, all non-grid connected households were considered as unelectrified. Possible supply through decentralized diesel generators is by definition not considered to provide electricity access, as its capacities are often not sufficient. All locations that are grid-connected through distribution lines but do not show sufficient night light emissions are considered as unelectrified, as it is assumed that the grid is not operational [11, 82f].

Demand profile estimation. With extensive surveying being too work intensive for the project's scope, the demand profiles are artificially generated for each location, laying the foundation for a techno-economic analysis of the different electrification options.
Individual daily demand profiles are generated for different customer types, including high and low demand private consumers, local public infrastructure, i.e. schools or med points, as well as of agricultural, small business and productive users based on a specific daily electricity consumption. Information on social infrastructure is collected and the number of high and low demand households is determined based on local economic activity. The number of agricultural, small business and productive users is defined as a factor of the total settlement population. Aggregated, the demand profiles result in the settlements daily hourly demand profile. This profile is repeated each day of the year. Seasonality of agricultural demand is introduced. To account for real-life variability of demand, an hour-to-hour as well as a day-to-day variance of 10 % is introduced. To match the initial daily consumption values with the randomized ones, the yearly demand profile is multiplied by a correction factor.
The resulting demand profiles are validated through a stakeholder discussion [11, 85ff]. A summary of the parameters used for the demand profile estimation can be found in Table A.4 in the appendix. A detailed description of the demand profiling can be found in [39].

Grid extension planning. As simplified network planning that does not take into account local topology can heavily underestimate necessary line lengths by about 30 % [75], geospatial data is included in the network planning methodology. This includes data sets on current grid infrastructure, unconnected clusters, roads, protected areas, topology and land cover. From that, promising corridors for potential grid extension lines are identified based on a number of weighted factors, i.e. proximity to roads and absence of steep slopes. A minimal spanning tree algorithm then finds the optimal grid extension network. This network is broken up into branches, springing from the currently existent utility grid and reaching far into the rural areas, and assigned costs. Their actual implementation can proceed in stages and is included in the later developed electrification plan [11, 89ff]. As a result, each project location can be attributed a specific distance that connects them to their branch.

Techno-economic evaluation of settlements. The generated demand profiles and drafted grid extension network are used for a techno-economic evaluation of the two electrification options in focus: MG and national grid extension. As a simplification it is assumed that all clusters with a peak demand below 50 kW would be electrified by SHS and not be included in detailed electrification planning.

For each non-electrified cluster a MG composed of PV panels, diesel generator and storage is optimized based on its Levelized Costs of Electricity (LCOE). An python-based simulation tool developed at the RLI, based on [76], [58], determines the least-cost capacities [11, p. 87].

Identifying the least-costs electrification plan. Electrification planning should take into account system costs, geographical proximity of clusters as well as likely state-wide developments, i.e. progress on national grid extension. The planning therefore requires a joint evaluation of the clusters and an optimization to electrify the population fast and (cost-) efficiently.
The state-specific electrification plans are divided into three succeeding stages, in which major electricity access milestones are reached. For each of the stages, the appropriate electrification option of each settlement is defined. As mentioned above, all clusters with a demand below 50 kW are assigned small-scale systems (SHS). MG are first implemented in the most promising and risk-free locations - far from the grid and with comparably low LCOE. Grid extension is only prioritized in settlements with high economic power. The optimal solution can change into another one from one stage to another, i.e. MG can interconnect with the arriving national grid [11, 99ff].

Results of electrification planning. With the above described work packages, the NESP study developed an electrification plan for five Nigerian states [77] [78] [74] [79] [80]. The research results are also visualized in an interactive webmap [81].
Currently, only 49.5 % of the 22 million inhabitants of the five evaluated Nigerian states enjoy electricity access, predominantly living in cities [11, p. 107]. All five states together have at least a peak demand of 1.4 GW, with about 150 to 180 kWh/capita/a [11, p. 113]. This value is comparably low, as the demand estimation mainly focused on households.
The GIS analysis finds 8,048 settlement clusters throughout all five states, of which only 2,051 clusters have a demand over 50 kW and are evaluated as MG project sites [11, p. 124]. The plan ensures a 100 % electrification rate in each of the five states until 2030 in three stages. To boost electrification rates in the first electrification stage MG adaptation plays a central role. They electrify more than 2.4 million people, while capacity building and the extension of the national grid in already grid-connected clusters electrifies about 2 million people. SHS supply almost 1 million people. In the second stage the grid is extended to about 2.6 million people, with 1.3 million of these previously electrified by MG adaptation. An interconnection of these MG is assumed. New MG and SHS bring electricity to almost 1 million people. The last electrification stage ensures electricity supply for all and is dominated by grid extension and MG interconnection.
Overall, grid extension is „found to be the most dominant solution for achieving cost-efficient electrification“ [11, p. 114], under the assumption that sufficient generation capacities are installed in stage 1, ensuring reliably, without increasing the current very low electricity price of 0.08 USD/kWh. Off-grid solutions are more important in states with lower population densities and less preexisting grid infrastructure, e.g. in Niger and Sokoto [11, p. 130].
The focus of the later on described case study of this master thesis lies on the state Plateau, as it shows one of the currently least electrification rates of 34.4 % (2.6 million unelectrified people) [11, p. 107] and grid infrastructure is underdeveloped. These two factors lead to 220 MG being installed and almost all of them later-on interconnected with the national grid.

Sokoto has a comparable number of MG, but in Plateau a higher number of MG is interconnected in the second electrification stage, making Plateau a perfect study area for MG design strategies taking into account imminent interconnection.
544 currently unelectrified settlement clusters with a peak demand of over 50 kW are identified in Plateau. While the grid already extends to 189 grid-connected clusters, only 26 of those are actually supplied. Ensuring grid-supply in the remaining 163 clusters is a priority of the first electrification stage. Additionally, the first stage includes MG adaptation in 109 clusters (0.5 million people). The second phase requires grid extension to 178 clusters on 62 branches, interconnecting 29 MG as well as the implementation of 108 off-grid MG. The last stage of electrification pushes for grid extension and MG interconnection (175 unelectrified and 182 MG sites on 65 branches). Only three villages remain supplied by off-grid MG. Reaching full electrification in Plateau is possible through major investments of 370 million USD, especially into the national grid infrastructure with 2887 km additional medium voltage electricity lines [11, p. 124].

4.3. Input parameters

While most of the original NESP study's input parameters (as summarized in Table A.6) are adapted to allow a direct comparison of the optimization results and interpretations, some simplifications have to be introduced (see Table 4.1). Additionally, each of the 524 clusters present in Plateau are characterized by a data set provided in [81]. Amongst others, the data set includes a cluster identification number, geo-location, number of consumers, distance from the current national grid, optimized capacities, electrification status in each of the electrification plan's stages and the number of the electricity grid branch, to which the project location will be connected to the central grid at some point in the future. Both net present value (NPV) or LCOE are not included in this data set.

Demand profiles. Load profiles for each cluster, a time series with 8,760 entries with hourly demand, is provided by an internal document. Community sizes vary with a population between 141 and 4,718 and an average of 465 inhabitants. The demand profiles of three days' duration and of three different villages, of 104, 440 and 704 inhabitants respectively, are displayed in Figure 4.1. A typical demand peak can be observed in the evening hours. Daytime demand increases with higher population due to the proportionally increasing number of commercial, agricultural and productive uses. The demand is shifted compared to renewable generation; for high renewable shares the systems need appropriately large sized battery storage.

Component models. Techno-economic input parameters for the components of the energy systems are provided, including specific investment and operation costs per unit installed and technology specifications:

- **PV plants.** Solar panels are installed with a tilt of 6 degrees [82] and a system efficiency decreased due to shading and others of 10 % [5, p. 74]. With the additional information of the geo-coordinates of the cluster settlements, solar generation time series per installed peak capacity (kWp) are acquired from [83]. Efficiency degradation is not considered.

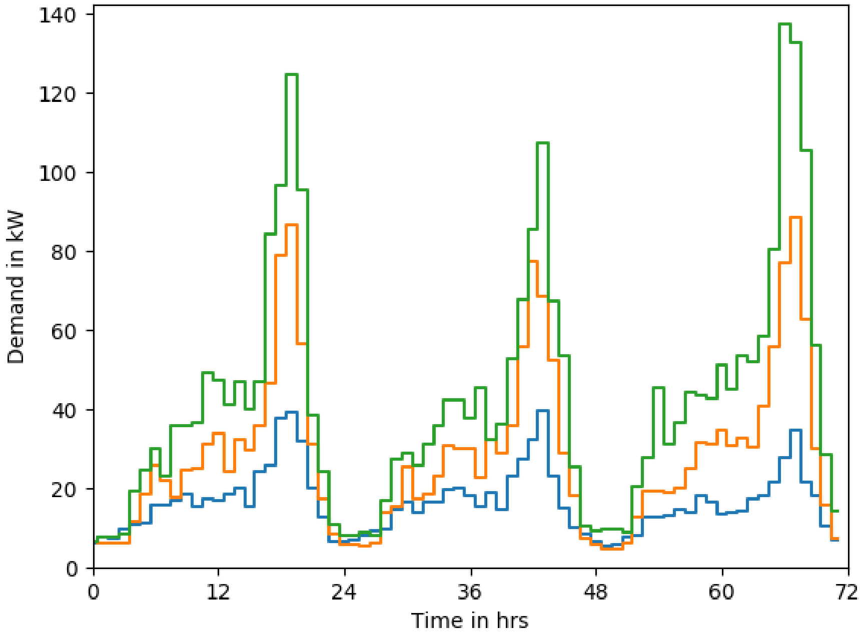


Figure 4.1.: *Examples of demand profiles provided by NESP study, for different settlement sizes*

- **Storage.** Storages have a constant charge efficiency and a fixed lifetime of 5 a. This is opposed to the NESP study input, in which the number of cycles is limited in addition to its lifetime, and thus takes into account battery aging based on its utilization. Further, batteries are modelled with an undefined initial charge in the simulation tool, better making use of oemof's capabilities, while the NESP study used an initial charge of zero.
- **Generator.** NESP study modelled each generator of peak demand capacity with variable efficiency [74], rotating mass and minimal loading. Due to oemof's limitations and to decrease simulation time, the tool's diesel generator model is simplified. It considers a constant generation efficiency of 33 % and np minimal loading.
- **Inverters and rectifiers.** The NESP study did not differentiate between Alternating Current (AC) and Direct Current (DC) bus and thus did not define the conversion efficiencies of inverters and rectifiers. To not stray from this optimization problem, losses and potential costs are be neglected for both components.
- **Point of Common Coupling (PCC).** The PCC, i.e. the transformer station, is according to NESP study sized to 150 % of the projects sites' peak load. To ensure reliability of supply even when one transformer ceases to operate, two transformers are installed. The costs of bi-directional inverters for interconnected MG, which allow feed-in electricity, are estimated with two transformers - one allowing consumption and one feed-in - as well as one replacement transformer each. Additional national grid extension costs are described below.

Table 4.1.: *Case study input parameters, based on NESP study [11].*
⋆) Component or parameter adapted compared to NESP study due to simulation tool limitations (original values see Table A.6)

Asset	Parameter	Unit	Value
PV	CAPEX	USD/kWp	1,250
	OPEX	USD/kWp/a	25
	Lifetime	a	25
Battery⋆	CAPEX (Capacity)	USD/kWh	250
	CAPEX (Power)	USD/kW	500
	OPEX	USD/kWh/a	6.75
	Lifetime⋆	a	13.5
	Maximum c-rate	kW/kWh	0.5
	Maximum SOC	%	100
	Maximum depth of discharge	%	80
	Charging efficiency	%	97
	Discharging efficiency	%	97
Diesel generator⋆	CAPEX	USD/kW	820
	OPEX (var)	USD/kWh	0.05
	Lifetime	a	10
	Efficiency	%	33
Distribution grid	CAPEX	USD/consumer	400
	OPEX	USD	1 % CAPEX
	Lifetime	a	40
Central grid	CAPEX (fix per branch)	USD	20,000
	Medium voltage grid lines		
	CAPEX	USD/km	20,000
	Lifetime⋆	a	40
	Point of Common Coupling		
	CAPEX	USD/kW	100
	Lifetime⋆	a	15
	Oversize factor	% peak demand	150
	Installed per cluster	amount	2
Project development	CAPEX	USD	20,000
	Project lifetime	a	20
Other	Diesel fuel price (t=0)	USD/l	0.68
	Annual diesel fuel price change	% p.a.	5
	Resulting adapted diesel fuel price	USD/l	1.04
	Electricity price of the national grid	USD/kWh	0.08
	Feed-in tariff (solar)	USD/kWh	0.05
	Stability limit	% of demand	20
	WACC	%	16

Additional parameters. Additional calculations had to be performed to estimate distribution and central grid extension costs. Diesel fuel price, stability limit and Feed-In Tariff (FIT) are defined.

- **Distribution grid.** While designing the distribution grid of a specific location, especially with low population density and/or difficult terrain, is a task in itself, the NESP study estimated its costs based on the number of consumers connected. Each connection was assumed to cost 400 USD and additional fixed project development costs of 20,000 USD were included. The distribution grid costs are calculated based on the number of customers for each of the clusters and added to all simulated electricity supply solutions.

- **National grid extension.** Central grid extension costs are estimated with fix and kilometer-specific investment costs $capex_{ext}$ in the NESP study. Each cluster is attributed the current distance from the next national grid interconnection point d_{CG}. From this, the study also developed a grid extension plan that optimized the building of lines into branches. The MG would connect to this dynamically growing grid. Therefore, the national grid extension costs are be based on this actual lines build and not the distance to the current grid. However, only branch number and not actual additional distance to be installed on one branch is provided by the clusters' information sheet. The additional grid extension costs for one location to the developing grid therefore have to be estimated.
  Each branch is assumed to be implemented as a single project with fixed development costs $CAPEX_{fix,proj}$. Each branches' total length $d_{tot,branch}$ is determined and, as the sum of their distances is not equal to the distance mentioned in [11] ($d_{tot,report}$), multiplied by a correction factor. Now, total branch costs $CAPEX_{ext,branch}$ can be calculated. Transformer stations are not included in these extension costs, as they are added through the simulation tool. The costs are distributed amongst all clusters ($CAPEX_{ext,loc}$), based on each clusters' additional line length d_{add} on their respective branch:

$$CAPEX_{ext,branch,i} = CAPEX_{fix,proj} + capex_{ext} \cdot d_{tot,branch,i} \cdot \frac{d_{tot,report}}{\sum_i d_{tot,branch,i}} \tag{4.1}$$

$$CAPEX_{ext,loc,i} = CAPEX_{ext,branch} \cdot \frac{d_{add}}{d_{tot,branch}} \tag{4.2}$$

- **Diesel fuel price.** The tool of the NESP study takes into account future annual diesel price changes r_{fuel}, This study's simulation tool optimizes a single operational year, requiring a constant fuel price. As fuel price changes have an essential influence on the optimization results, the equivalent fuel diesel fuel price for the whole project time is calculated:

$$p_{fuel,adapted} = \sum_{t=0}^{19} \frac{p_{fuel,1} \cdot (1+r_{fuel})^t}{(1+wacc)^t} \cdot \frac{1}{CRF} \tag{4.3}$$

For the case study, this leads from a diesel price of 0.68 USD/l (NESP study) to an equivalent diesel price of 1.04 USD/l including fuel price change for the whole time period.

- **Stability constraint.** As some stability-related technical parameters of the diesel generator has to be neglected, the previously defined energy and power reserve constraints (see Equations 3.1 and 3.2) are applied to ensure technical feasibility of the optimized MG. The stability limit is chosen to be 20 % of the demand. This should be sufficient even for notable parallel volatilities of solar generation and demand, as operating reserve is always existent through the diesel generator sized to cover peak load .
- **National grid supply and feed-in.** The unreliability of the Nigerian national grid is defined by an average blackout frequency of 32.8 per month of 11.6 hrs duration on average (2014) [14] with a standard deviation of 15 %.
  According to [71, p. 20] renewable generation sites of at least 1 MW capacity are eligible for a FIT of 0.177 USD/kWh. The MG in question are not large enough to make use of this regulation. Still, a feed-in tariff of 0.05 USD/kWh is be assumed. Otherwise, interconnected MG, that are allowed to feed-in, would behave just as MG only allowed to consume (except if electricity excess was penalized).

The economical calculations use a Weighted Average Cost of Capital (WACC) of 16 %. Each project has development costs of 20,000 USD and the project duration is set to 20 a.

4.4. Scenario development

In the following, multiple scenarios are applied to the described case study. First, the tool's performance is validated. Then, the predominant assumption, that MGs designed for off-grid operation will be left as sunk costs as soon as the grid arrives, is evaluated. Lastly, the potential of a number of post-interconnection options is analyzed. Both a scenarios of an arriving reliable and unreliable grid are considered.

4.4.1. Scenario 1: Simulation tool validation

To validate the newly developed simulation tool, an off-grid MG with PV panels, storage and diesel generator is optimized for each of the locations in the Plateau region (Off-MG). The optimized capacities as well as the aggregated costs can then be compared to the optimized capacities and developed electrification plan of the NESP study.

4.4.2. Scenario 2: On-grid performance of off-grid micro grids

For almost all of the MGs identified within the electrification planning process, a connection to the national grid is planned later in time. However, commonly it is assumed that the operation of MG designed for off-grid operation is terminated after a central grid arrives. As such, MGs at project locations expecting grid arrival tend not to be implemented.

This paradigm is evaluated with scenario 2: The LCOE of both electricity provision through the arriving national grid and of the interconnecting MGs are determined and compared. This is performed for both a connection to a reliable as well as to an unreliable national grid:

1. **CG:** Supply of cluster solely through national grid extension.
2. **Off-MG-C:** Performance of above optimized off-grid MG after interconnection with reliable central grid, only consuming electricity.
3. **Off-MG-C:** Performance of above optimized off-grid MG after interconnection with reliable central grid, consuming and feeding in electricity.

The PCC only allows consumption from and feed-in to the central grid, if this does not experience a blackout event in that specific time step. The boolean blackout time series, universal for all project sites, is randomly generated.

4.4.3. Scenario 3: Potential of post-interconnection options for MG operation

After grid arrival, the MG might have to change its operation to adapt to the new situation. As such, in scenario 3, a number of possible post-interconnection MG options are evaluated. The cases are based on findings of [8], which are summarized in Section 2.3.5.
The time of grid arrival is taken into account. It it assumed, that each MG operated off-grid for 5 years, until the central grid arrives. Both interconnection with a reliable and an unreliable grid are considered. The post-interconnection options are presented in the following. Their NPV includes both the off-grid MG's operation until grid arrival, as well as future operation costs (if applicable).

1. **CG:** Costs of electrification through central grid, no MG implementation
2. **Off-MG:** Continued off-grid operation of MG, no interconnection with arriving grid.
3. On-grid operation of MG designed for off-grid operation.
    a) **Off-MG-C:** Interconnection allows electricity consumption from the central grid.
    b) **Off-MG-CF:** Interconnection allows electricity consumption from and feed-in into the central grid.
4. Adaptation of off-grid MG design on on-grid operation at grid arrival. The time of grid arrival is neglected when optimizing on-grid MG capacities, i.e. capacities that were installed in Off-MG are not included as pre-existing and might not be further utilized.
    a) **On-MG-C:** Interconnection allows electricity consumption from the central grid.
    b) **On-MG-CF:** Interconnection allows electricity consumption from and feed-in into the central grid.
5. **SPP**: The MG operator transforms into a small power producer (SPP) by selling the distribution grid to the utility at the price of its residual value at time of interconnection and at the same time abandoning diesel generators and storage. As an SPP, it then sells all renewably generated electricity to the national grid at FIT. To be able to do so, a grid-tied transformer station of peak solar generation capacity has to be installed.

6. **SPD**: The MG operator transforms into a small power distributor (SPD), i.e. abandons all generation and storage capacities and only continues distribution grid operation. Electricity is bought from the grid at retail (98 % of electricity price) and sold to the community with a profit margin of 2 %.

7. **Abandonment:** The MG is abandoned at grid arrival without reimbursements, i.e. assets are left stranded as commonly feared. Abandonment costs include the costs of stranded assets.

8. **Reimbursement:** When the grid arrives, the MG operator receives a reimbursement and the MG's operation is terminated. The arriving national grid continues to use the distribution grid. The reimbursement is defined in [72]. It includes reimbursement for the depreciated value of the implemented system in interconnection year calculated from NPV, annuities and avoided fuel expenditures, as well as a year's worth of revenues, estimated to equal the system's LCOE and an additional profit margin r of 2 %.

A detailed description of all the economic calculations providing NPV and LCOE for the scenario comparision can be found section A.3 in the appendix. The economic parameters of all post-interconnection options are calculated both representing MG operator's and electrification planner's perspective. From the MG operator's perspective, the costs neither include costs connected to transformer stations nor grid extension, as it is assumed that the utility carries these costs. From electrification planner's perspective, the total costs are considered, i.e. operators costs, extension, abandonment as well as reimbursement costs.
If the distribution grid of the off-grid MG was discontinued without reimbursement, it is assumed that it did not adhere to national standards. A new distribution grid has to be implemented, from the electricity planner's perspective, to supply the location through utility grid supply.

4.5. Scenario 1: Simulation tool validation

The optimal capacities a PV-hybrid MG for each cluster settlement is determined within Scenario 1. For that, the simulation tool developed in Section 3.3 is applied to the case study. The techno-economic optimization finds the optimal capacities and their dispatch for each of the 544 settlement clusters in Plateau State.

4.5.1. Results

To visualize the optimizations performed, an exemplary project site, *nesp 3670*, is presented. To validate the simulation tool, the results in terms of average and aggregate MG costs are presented. They are discussed and, as possible, compared to the results of the NESP study in the following section.

Detailed assessment of project site *nesp 3670*. In Figure 4.2 the dispatch of each of the installed generation and storage components of *nesp 3670* is visualized. The location-specific load profile, characterized by a peak demand of 66.3 kW, results in an optimal PV system capacity of 36.2 kW_p. It is able to cover the whole day-time demand. During times of 100 % renewable supply, stability is ensured through utilization of a diesel generator or sufficient charge of the 4.6 kWh battery. The generator is used in the night, covering all demand. The first evening hour is partly provided through battery discharge. In total, the MG has an annual fuel consumption of 288,653 l/a, resulting in a renewable share of 35.5 %. The MG has an NPV of 374.8 kUSD, of which 58.8 kUSD have to be paid for the distribution grid while total fuel expenditures make up the bulk of the costs with 182.4 kUSD. The system's LCOE is 44.7 USDct/kWh.

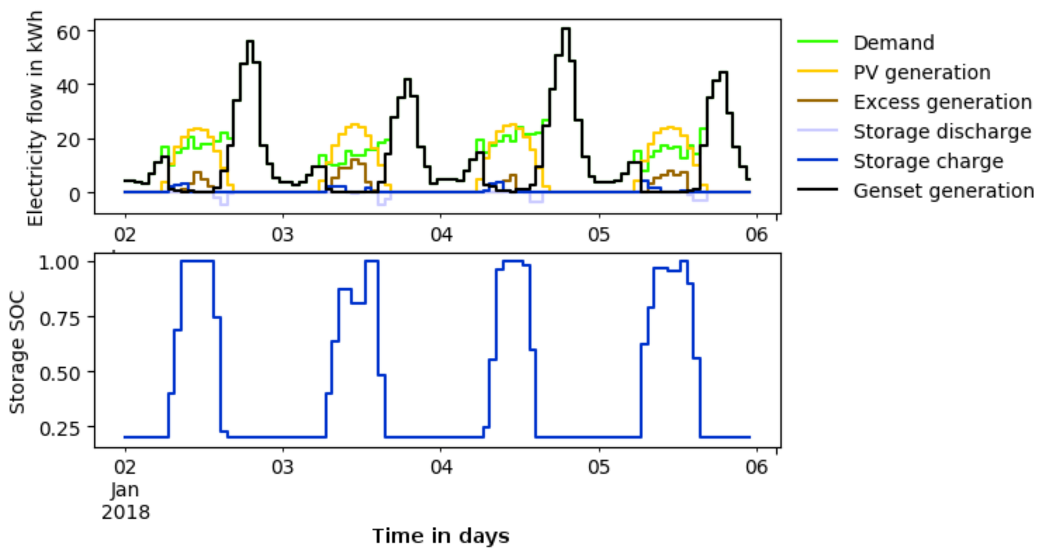


Figure 4.2.: *Energy flows in off-grid MG (nesp 3670)*

Comparison of optimized capacities. For each of the project locations, the optimized capacities of the NESP study, provided in [81], are compared to the results of the simulation tool. The simulation tool results in lower capacities than the NESP study (see Table 4.2). The generator capacities deviate by -2.8 % on average, i.e. are smaller than in the NESP study. There are instances that the generator is sized larger by up to 14.8 %, while the maximum deviation is -29.2 %. PV panels are sized -18.5 to -67.7 % smaller than in the NESP study, with an average deviation of -52.4 %. Storage capacities show the highest deviation. They are sized -94.1 % smaller, within an interval of -66.5 to -97.6 %.
In the whole state Plateau, for settlements of over 50 kW peak demand, a total of 36.8 MW_p PV, 9.8 MWh storage and 66 MW diesel generator capacity needed to be installed. Effectively, this results in renewable shares ranging from 33.6 to 41.9 %.

Table 4.2.: *Disparity of optimized capacites with simulation tool and in NESP study*

Component	Unit	Min (%)	Average (%)	Max (%)
Generator	kW	0.0	−2.8	−29.2
PV panels	kW_p	−18.5	−52.4	−67.7
Storage	kWh	−66.5	−94.1	−97.6

Average system parameters. The average MG has 466 customers, a total population of 2,468 and a peak demand of 121 kW. Electricity can be supplied by off-grid MG for 42.9 USDct/kWh in Plateau State, ranging from 35.3 USDct/kWh to 46.8 USDct/kWh. The NPV however varies between 252.5 and 6,257.8 kUSD, with an average value of 680.4 kUSD. On average, this translates to an NPV per household of 1,480.7 USD/HH, and a specific NPV per kW demand of 5.7 kUSD/kW (see Table 4.3).

Table 4.3.: *Parameters of optimized off-grid MG, average and range*

Value	Unit	Min	Average	Max	Standard deviation
Customers	-	141.0	465.6	4,718.0	391.9
Population	-	749.0	2,467.6	25,005.0	2077.2
Peak	kW	41.1	121.4	1,146.3	105.1
Diesel generator	kW	41.1	121.4	1,146.3	105.1
Transformer station	kW	61.7	182.1	1,719.4	157.6
PV panel	kW_p	23.1	67.6	613.6	57.8
Storage	kWh	5.9	18.1	176.0	5.9
Storage	kW	2.9	9.0	88.0	7.8
Renewable share	%	33.5	36.7	41.9	1.3
LCOE	USDct/kWh	35.3	42.9	46.8	1.9
NPV	kUSD	252.5	680.4	6,257.8	570.1
NPV per household	USD/HH	1,298.5	1,480.7	3,097.7	223.3
NPV per kW	kUSD/kW	4.8	5.7	7.6	0.3

Table 4.4.: *Average economical parameters of electrification stages*

MG implementation	Number of customers	LCOE USDct/kWh	NPV kUSD	NPV/HH USD/HH	NPV/kW kUSD/kW
Stage 1	895	41.0	1,343.6	1,560.3	5.7
Stage 2	406	42.0	596.7	1,541.7	5.8
Stage 3	228	44.9	319.5	1,397.4	5.8
No MGs	343	43.7	488.6	1,434.4	5.7

System costs per electrification stage. The average costs vary per electrification stage. The 109 MG project sites that adapt an off-grid MG in stage 1 have the lowest LCOE with 41.0 USDct/kWh, while their total project costs are highest with 1,344 kUSD per MG. On average, the 108 MG in stage 2 have a higher LCOE of 42.0 USDct/kWh, while the NPV is much lower with 597 kUSD per project. Stage 3, again, shows increased LCOE (44.9 USDct/kWh) with project costs of 319.5 kUSD on average. The 324 settlements that were not assigned a MG in [11], [81] are named *No MG* project sites in this study. Their LCOE is with 43.7 USDct/kWh higher than those of the stage 1 or 2 MGs.
The average MG investment costs per household vary only between the stages and range from 1,397 to 1,560 kUSD/HH. The NPV per kW demand vary slightly between 5.7 to 5.8 kUSD/kW. The total investment necessary into MGs amount 147 million USD in stage 1, 64 million USD in stage 2 and 1 million USD in stage 3. *No MG* project sites, if MG were to be implemented, would have total MG investment costs of 158 million USD.

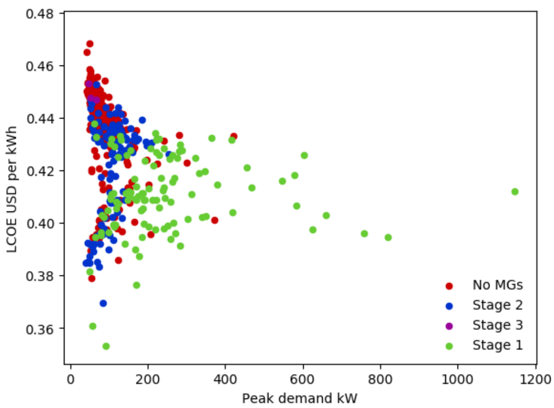
4.5.2. Discussion

Scenario 1 helps to both assess the performance of the oemof-based simulation tool by comparing its optimized capacities to the results of the NESP study, as well as to evaluate its proposed electrification stages.

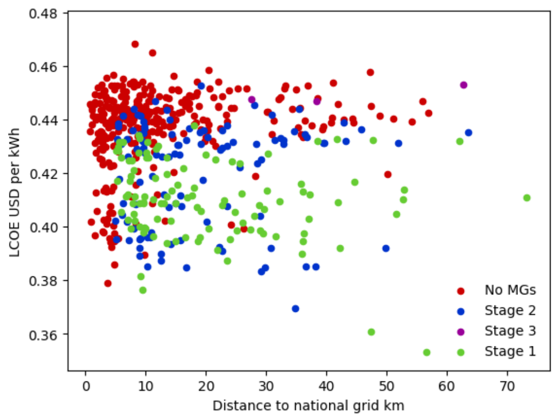
Comparison of optimized capacities. A comparison of the optimization results of the created simulation tool and NESP study shows major differences. The optimized generator capacity of the simulation tool deviates from the webmap's data by -2.8 % on average, with a standard deviation of 8.4 %. In extreme cases the deviation results in up to 50 kW higher or 281 kW lower generator capacity than in the NESP study.
Looking closer at the webtool's data set [81] reveals that the peak demand of the data set is on average 31.8 % higher than the peak demand of the provided demand profiles. Even though the generator should per definition be sized after peak demand, its capacity fits neither the webtool's data set's, nor demand profiles' peak demand. This deviation also persists comparing the webtool's data set to an internal data sheet summarizing the peak demand of the project locations. It seems likely that some assumptions regarding demand, demand growth, or generator sizing have not clearly been communicated within the NESP study's report. For the further analysis it is assumed that the simulation tool's optimized capacites are appropriate for the respective project locations.

PV panels are sized about half as large as in the NESP study. The component model of the PV panels used in the NESP study is not known in detail, and the deviation could be an effect of panel degradation, differing system efficiency and solar generation time series.
The storage capacity is sized majorly lower with the simulation tool of this study, amounting only to a very low share of about 6 % of the NESP study's capacities. A part of this deviation can be attributed to the static battery model used, instead of a lifetime based on charge cycles. Not taking into account the generator's minimal loading could have contributed.
However, for both PV panel, battery and diesel sizing deviations, the main reason may lie within oemof itself: While the tool used for the NESP study is based on rule-based dispatch algorithms for each time step individually, the simulation tool presented here optimizes capacities and dispatch with perfect foresight. The difference can be major: [51] presents that a case study optimized with both an oemof-based model and Homer can result in highly diverging capacities. While in that specific case, PV sizing deviation was low with only 9 %, the battery capacity showed a relative deviation of 46.9 %. The perfect foresight also led to 35.7 % less excess electricity [51]. The simulation result's deviation from the optimized NESP study capacities is therefore expected as well as acceptable.
As a result of the lower installed capacities of PV panels and battery, renewable penetration of this study's off-grid MGs are comparably low when looking at the NESP study's result: On average, the MGs of the NESP study had a renewable share of 69 %, with a minimum of 45 % and a maximum of 93 % [11, p. 124]. The systems optimized with the oemof-based tool however only have an average renewable share of 36.7 %.

System costs per electrification stage. The electrification stages proposed in the NESP study can not unambiguously be distinguished when evaluating the tool's simulation results based on their distance from the grid, peak demand or costs alone (see Figures 4.3a and 4.3b). While each of this parameters can vary highly from location to location, some trends can be identified based on their distribution and average LCOE per stage: Project sites with the lowest LCOE and high peak demand are electrified first in stage 1, while in stage 2 MG projects with slightly higher LCOE are implemented. Stage 3 MG have a higher LCOE than *No MG* locations, but its small sample size does not allow further analysis.



(a) *Based on peak demand*



(b) *Based on current distance to the grid*

Figure 4.3.: *Distribution of Levelized Costs of Electricity*

These tendencies are in line with the assumptions of the electrification plan developed in the NESP study: Specifically, electrification in stage 1 reaches the clusters with the most customers (average of 895 customers) and the highest demand (average of 242 kW). These locations are the lowest hanging fruit that [11, p. 131] identified, i.e. the project sites with the highest potential. With more agricultural, business and productive users, the peak demand (see Figure 4.3a) and NPV per customer is high compared to the other stages. Number of customers electrified, covered peak demand and NPV of the MG projects decrease with the proceeding stages.
In stage 3, the peak demand only is about 55 kW on average, and the distance to the current central grid is high. *No MG* clusters can be found closest to the central grid and have comparably high LCOE, as displayed in Figure 4.3b. Knowing the time frame of central grid extension to each project site might have allowed a clear stage distinction.
The investment costs connected to each stage are very similar to those of the electrification pathway described in [11]. While the tool's MG investment costs for stage 1 amount to 147 million USD, the NESP study quotes 142 million USD. Stage 2 has higher investment costs with 64 million USD compared to 62 million USD in NESP study. Stage 3 MG can be implemented for 1 million USD according to the simulation tool and 0.9 million USD according to NESP study [74]. The deviation can spring from the observed sizing difference. Overall, the observations support the electrification decisions presented in [11].

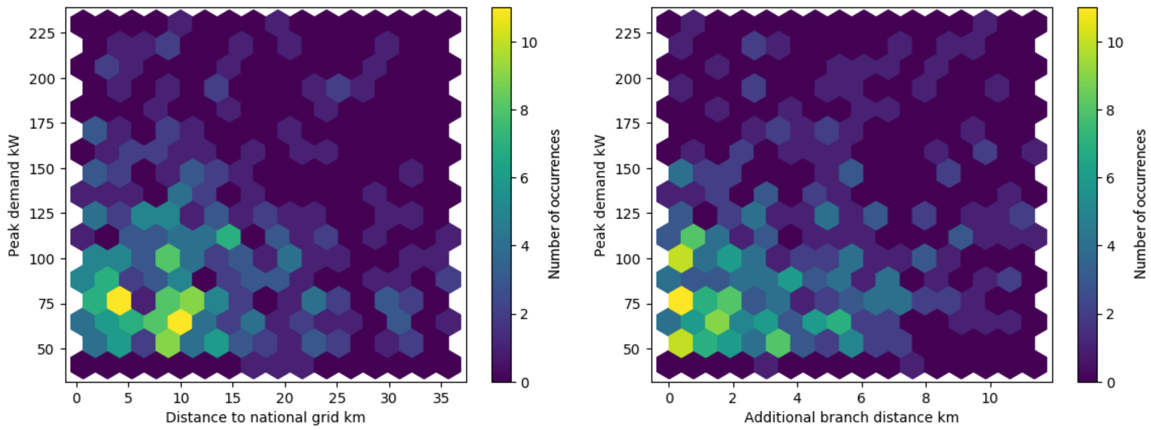
4.6. Scenario 2: On-grid performance of off-grid micro grids

Scenario 2 assesses the paradigm of MG being terminated when the central grid arrives for all 544 project sites. For that, an off-grid MG's interconnection with a reliable central grid is simulated. This is compared to the performance of the off-gird MG connecting to an unreliable central grid, as intermittant supply is common in Nigeria and many other countries. The costs are calculated and compared as if implementation was possible in the same year.
The following abbreviations are introduced to address the different MG architectures:

- Central grid (CG)
- Off-grid micro grid (Off-MG)
- Micro grid designed for off-grid operation, connected to central grid for consumption (Off-MG-C)
- Micro grid designed for off-grid operation, connected to central grid for consumption and feed-in (Off-MG-CF)

4.6.1. Results

First, the spatial project site distribution and blackout randomization results are presented. Then, the scenario and results are visualized through the exemplary project location, *nesp 3670*. The four interconnection options of previous off-grid MG are presented for both reliable and unreliable central grid conditions, focusing on aggregated and mean values.



(a) *Distance to current central grid* **(b)** *Additional branch distance*

Figure 4.4.: *Distribution of project sites (outliers excluded, 0.9 quantile)*

Distribution of project sites. As visualized in Figure 4.4a, the 544 project locations in state Plateau vary in peak power demand and distance from the central grid. Most project sites can be found around 5 to 10 km from the current central grid, with a peak demand between 50 and 75 kW. There are, however, also project locations that are further away from current central grid infrastructure and have very high peak demand. These extreme cases are not displayed in Figure 4.4a, as it is limited to project locations in the 0.9 quantile. Outliers are for example a project location farthest away from the current central grid with a distance of 73 km. The largest project site has a peak demand of 1,146 kW, with an average MG peak demand of 242 kW, and a lowest MG peak demand of 41 kW.
The project site distribution based on the additional branch distance, i.e. the grid extension distance needed to connect a location to their specific branch, is visualized in Figure 4.4b. The distribution has a higher variance, but shows that most project locations are planned to be close to the future central grid. Most clusters are located at a distance of 0 to 4 km from the future central grid. They have a peak demand ranging between 50 to 110 kW. The additional branch distance determines the national grid extension costs.

Blackout randomization. The blackout randomization results in the central grid being available 60.2 % of the time with an annually accumulated 3,465 hrs blackout duration, distributed over 216 events. On average, this translates to 60.2 % of the demand of a project location being supplied when the central grid is extended to it.

Detailed assessment of project site *nesp 3670*. When connecting the off-grid MG, supplying project location *nesp 3670*, to the central grid, the diesel generator is not further utilized and its fuel expenditures of 30.8 kUSD/a are being replaced by consumption from the central grid (see Figure 4.5). This results in electricity expenditures of 7.6 kUSD per year for consumption from the grid. For the interconnection itself, 114.9 kUSD investment is needed to implement national grid extension. Additionally, 18.9 kUSD have to be spent on the installation of a transformer station.

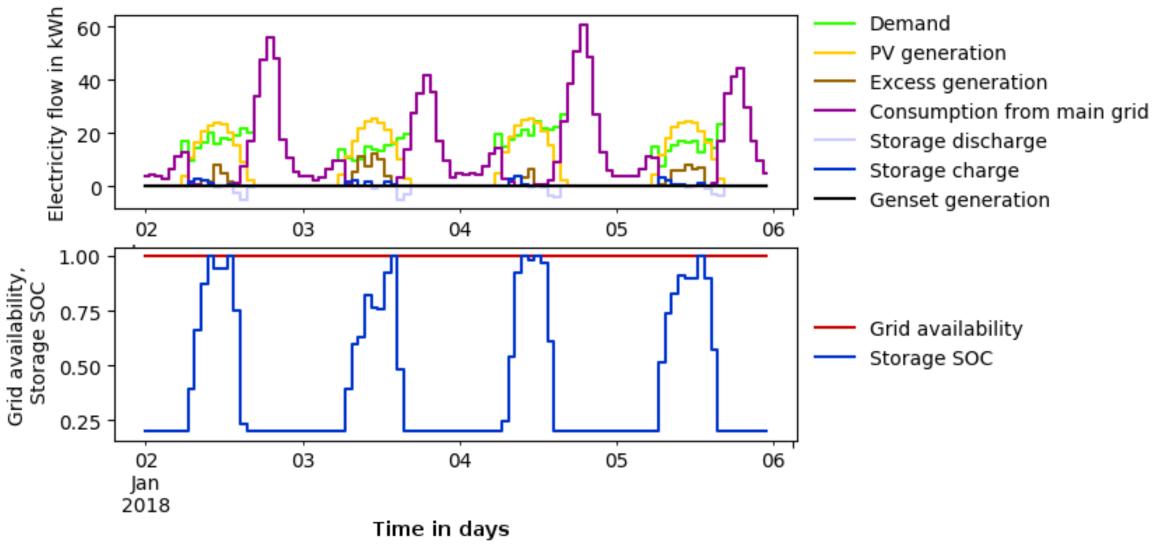
If only consumption from the central grid is possible (Off-MG-C), the LCOE of the MG decreases minorly from 44.7 USDct/kWh in off-grid operation to 44.3 USDct/kWh. Both PV panels and storage are continued to be utilized, leading to an autonomy factor of 32.9 %.
To enable feed-in of the interconnected MG (Off-MG-CF), the transformer station has to allow a bi-directional flow, leading to an additional investment costs of 18.9 kUSD. Feed-in revenues of 315 USD/a, adding up to 1.9 kUSD over the whole project lifetime, can not offset this investment, leading to an increased LCOE of 46.4 USDct/kWh.
Electrifying the settlement through central grid extension (CG) alone would be the least-cost option with an LCOE of 33.3 USDct/kWh, including electricity expenditures of 11.3 kUSD/a. Opposed to that, interconnecting the off-grid MG of *nesp 3670* with an unreliable central grid increases the system's overall costs. Grid consumption replaces generator operation when the grid is available (see Figure 4.6), decreasing its fuel expenditures down to 11.3 kUSD/a and replacing avoided costs with electricity expenditures of 4.8 kUSD/a. The annuity of grid extension, transformer costs and electricity expenditures are higher than the avoided fuel expenditures, leading to an increased LCOE of 50.3 USDct/kWh (Off-MG-C). Installing a bi-directional transformer station to allow feed-in leads to an even higher LCOE of 52.5 USDct/kWh (Off-MG-CF), with low annual revenues of 185 USD/a. Both interconnected cases have, due to lacking grid reliability, a high autonomy factor of about 57 %. Using the central grid extension alone to supply the settlement (CG), would have a very low supply reliability of 61.5 % and comparably high LCOE of 49.1 USDct/kWh. Continuing off-grid MG operation would be the cheapest reliable supply option.

Interconnection with a reliable central grid. Extending the central grid is only in three cases more expensive than supplying a location through an off-grid MG. Additional investments of, on average, 48.5 kUSD for grid lines and 34.6 kUSD for an uni-directional transformer station (69.1 kUSD for a bi-directional transformer station) are necessary to extend the central grid to a settlement. In total, 44.3 million USD are necessary to connect all project sites to the central grid uni-laterally. Allowing those locations to feed back into the grid would increase the investment costs to 63.1 million USD. Supply through the central grid alone (CG) results in an LCOE of 23.0 USDct/kWh and amounts to only half of the off-grid MG's NPV, NPV per household and NPV per kW (see Table 4.5). On average, connecting a MG project to a reliable central grid decreases LCOE from its off-grid value from 42.9 to 33.5 USDct/kWh (Off-MG-C). Still, about 32 project locations have a lower LCOE staying off-grid. With a bi-directional interconnection, the LCOE increases to 35.3 USDct/kWh (Off-MG-CF).

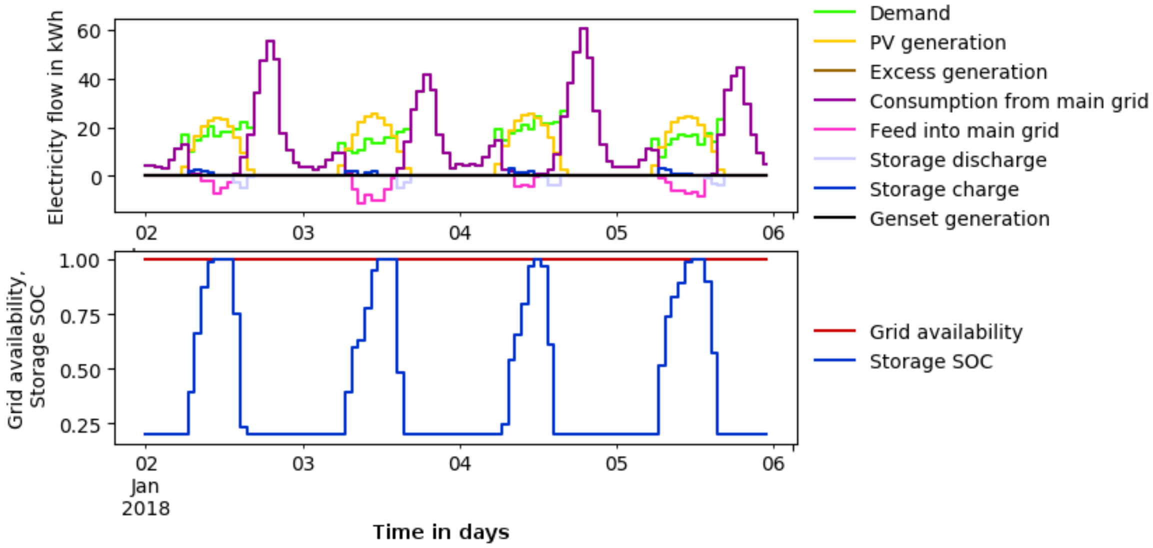
Table 4.5.: *Techno-economic assessment of electrification solutions, reliable national grid*

	Reliability %	Autonomy %	LCOE USDct/kWh	NPV kUSD	NPV/HH USD/HH	NPV/kW kUSD/kW
CG	100.0	0.0	23.0	334.7	789	3.04
Off-MG	100.0	100.0	42.9	680.4	1,480	5.68
Off-MG-C	100.0	33.8	33.5	502.1	1,150	4.43
Off-MG-CF	100.0	33.6	35.4	533.0	1,216	4.68

Average values considering all project locations

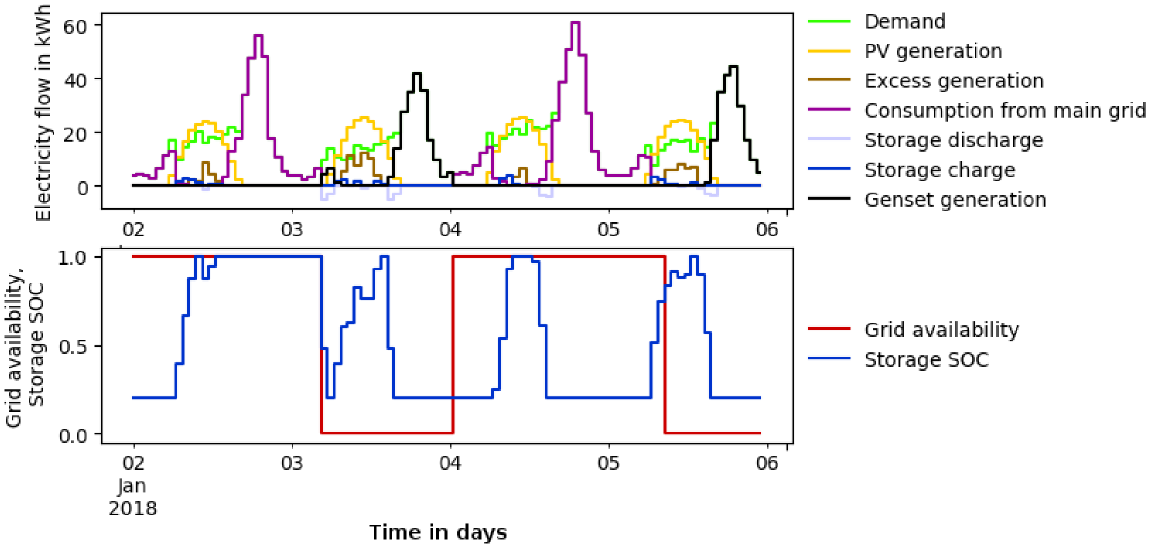


(a) *Only consumption from central grid*

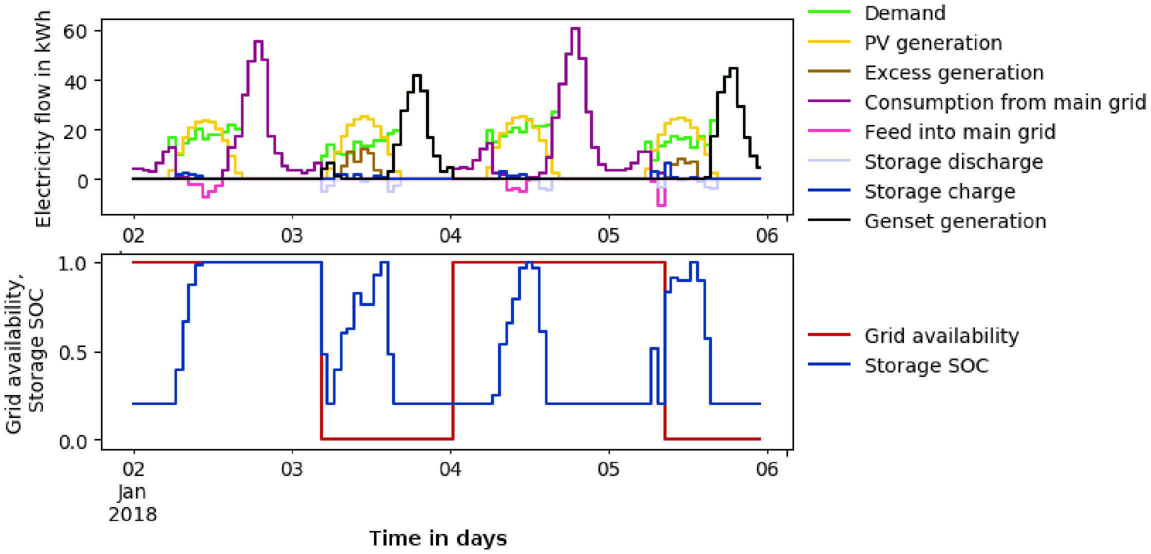


(b) *Consumption from and feed-in into central grid*

Figure 4.5.: *Energy flows in off-grid MG connected to reliable central grid (nesp 3670)*



(a) *Only consumption from central grid*



(b) *Consumption from and feed-in into central grid*

Figure 4.6.: *Energy flows in off-grid MG connected to unreliable central grid (nesp 3670)*

Table 4.6.: *Techno-economic assessment of electrification solutions, unreliable national grid*

	Reliability %	Autonomy %	LCOE USDct/kWh	NPV kUSD	NPV/HH USD/HH	NPV/kW kUSD/kW
CG	60.2	0.0	33.0	283.5	677	2.61
Off-MG	100.0	100.0	42.9	680.4	1,481	5.67
Off-MG-C	100.0	59.3	39.7	601.9	1,366	5.24
Off-MG-CF	100.0	59.2	41.7	634.3	1,435	5.51

Average values considering all project locations

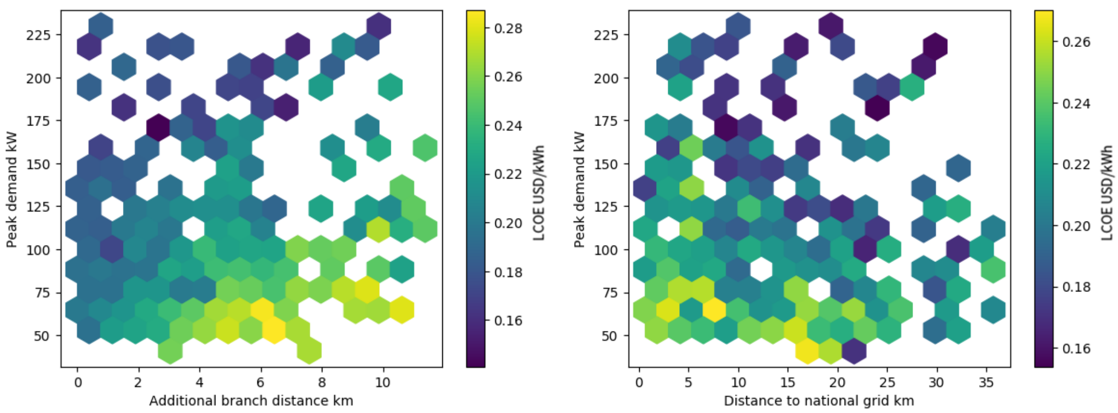
Interconnection with an unreliable central grid. If the arriving grid is highly unreliable, 77 projects (17.7 %) have a lower LCOE off-grid than supplied by grid extension (CG). This includes 51 potential *No MG* project locations as well as 24 clusters of stage 2 and two clusters of stage 3. Grid extension could only satisfy 60.0 % of a project site's demand on average. The reliability varies dependent on the demand curve, between 57.1 and 61.5 %. Alike the case of the reliable grid, central grid extension results in an 50 % lower NPV, NPV per household and per kW (see Table 4.6). The LCOE of unreliable electricity supply solely through the central grid amounts to 33.0 USDct/kWh.
Connecting an off-grid MG with an average LCOE of 42.9 USDct/kWh to the grid leads to decreased operation costs of 39.7 USDct/kWh (Off-MG-C). A bi-directional transformer station allowing feed-in (Off-MG-CF) leads to an LCOE of 41.7 USDct/kWh. The MG sites have a high factor of autonomy from the grid with about 57 %.

4.6.2. Discussion

The decision to use the project sites' distance to the future national grid infrastructure to estimate grid extension costs has a large influence on the simulation results. As such, a reliable grid has low LCOE and the paradigm of MG being abandoned upon grid arrival without an enabling legal framework can be confirmed. However, in case of interconnection with an unreliable grid, the paradigm should to be questioned. In this setting, the central grid can only cover a fraction of the actual demand of each settlement. For a future analysis, it should be kept in mind that the randomized grid availability time series deviates from the provided input values.

Distribution of project sites. The clusters identified in the NESP study vary in peak demand, but also regarding their distance to the central grid, as shown in Figure 4.4a. As the NESP study developed an electrification plan for Plateau, it is possible to take the future shape of the central grid with its additionally implemented branches into account.
As shown in Figure 4.4b, many of the project sites are in proximity to the future central grid and require short additional branch distances to be built to connect them to it. This confirms that the central grid is built to minimize the total grid extension distance and, thus, electrification cost.

Further, the LCOE increases based on the additional branch distance from 21 to 28 USDct/kWh for smaller sites (see Figure 4.7a). Those clusters with low peak demand are especially concentrated close to the future grid. Thus, the electrification plan succeeds in minimizing the costs of these locations of lower demand and with that the bulk of project sites.
The decision to include grid extension costs based on the additionally needed distance to be covered and not the current distance to the central grid has essential effects on the study's outcome. Usually, when searching for the best supply solution in the near future, the actual distance from the grid is used to decide between off-grid electrification and grid extension. As such, there is a general tendency of increasing electrification costs further away from the current central grid and MG projects appear especially favourable far away from the grid. Using the additional line length, however, turns this tendency almost upside-down: Figure 4.7b shows that LCOE are comparably high close to the current central grid with about 25 USDct/kWh, while they decline with increasing distance, achieving LCOE of about 20 USDct/kWh.
With the decision to base the extension costs on the electrification plan developed by [11], supply through the central grid appears cheaper for all locations because extension costs intrinsically are minimized and the central grid's electricity price is low. However, these low central grid extension costs do not account the time until the grid arrives and thus underestimate one of MG's most important advantages: timely implementation.
Still, as this study addresses not an individual project location and finds its optimal supply solution today, but rather tries to further characterize the role of MG in a multi-stage electrification plan, it is beneficial to use the actual central grid extension costs per project location and not the imaginary distance to be covered if the grid was extended in the near future. This would, in sum, highly overestimate centralized electrification costs. The dependency on time of grid arrival is evaluated within Scenario 3, Section 4.7.



(a) *Additional branch distance, electrification plan*

(b) *Distance from current central grid*

Figure 4.7.: *Comparison of central grid supply costs based on current and future distance from the central grid (outliers excluded, 0.9 quantile)*

Blackout randomization. The blackout randomization overestimates the availability of the central grid. Using the averages of outage frequency and duration provided by [14], about 394 outages should occur over the year, resulting in about 4,566 hrs without electricity (47.9 % availability). The randomization process however sets the blackout occurrence starting times first and allows each blackout to overlap. Overlapping blackouts are only registered as a single blackout of potentially much higher duration than the average value used as input suggested. For this case study, this translates to 18 outages per month on average with an duration of 16 hrs. This results in a overestimated grid reliability of 60.4 % in terms of availability and ability to provide demanded electricity. Based on [14], however, the share of electricity that companies self-sustainably supply through generator utilization amounts to 58.8 % (2014), translating into a grid supply reliability of 41.2 %. With a deviation of the randomized availability time series from the actual distribution of blackout occurrences, the optimization results of the grid-connected energy systems will deviate as well, which, especially considering a higher necessity for autonomy, influences backup battery sizing.
As this case study is to identify general tendencies, the grid reliability deviation is an acceptable error, which influences the optimization of all grid-connected systems equally. For the evaluation of specific MG project sites and their potential upcoming grid interconnection, however, it is recommended to either improve the randomization algorithm or use an actual measured grid availability time series. This time series could also take into account specific local conditions, e.g. potentially increased outage risk at fringes of the grid, seasonality of blackouts and their likelihood to occur in different hours of the day.

Interconnection with a reliable central grid. Grid-interconnected operation allowing consumption from the grid (Off-MG-C) is preferred over grid-connected operation allowing feed-in (Off-MG-CF). Transforming into an interconnected MG would decrease the LCOE of 512 of the project locations, while only 32 of the 544 settlements would prefer to remain off-grid. However, if a connection to a reliable central grid was implemented, only three of the evaluated project sites would have a lower LCOE continuing operating without using the grid. This includes two MG implemented in stage 3 and one settlement, in which no MG project is planned according to [11].
The price difference between central grid electricity costs and the on-grid MG's LCOE is steep. As a result, if no appropriate policies are in place at grid arrival, almost all MG would face termination: Not a single on-grid MG would have lower LCOE than the sole central grid supply. Grid extension costs are included in this costs. A detailed look at the differences of decision making processes from the operator's opposed to the global, electrification planning point of view is presented in the following Section 4.7 (Scenario 3).
While this study finds grid extension to cost 44.3 million USD, the NESP study cites costs of 87 million USD for medium voltage lines, transformer stations and project costs [74]. It is likely that the estimation of grid extension costs is based on a greater level of detail in the GIS analysis performed in the NESP study.
The evaluation of Scenario 2 confirms the paradigm, that central grid arrival, when offering reliable supply, endangers MG operation and can lead to termination, if no appropriate frameworks regulating interconnection or policies are introduced. This could for example be accomplished by subsidizing on-grid MG electricity supply, e.g. covering the margin between the electricity tariff of the central grid and the actual electricity generation costs. This could also allow uniform electricity tariffs throughout the country (comp. [8, p. xii]).

Interconnection with an unreliable central grid. Supply through the central grid (CG), even though intermittent, is the cheapest supply solution on average. However, it is lacking reliability to a degree that it can not be recommended as the go-to solution for electrification in the near future. As central grid extension could only supply about 60 % of the demanded electricity due to frequent outages, 77 project locations have lower LCOE than the central grid supply and are better served staying off grid. 155 locations (35.9 %) experience increasing prices when connecting to the grid and, thus, should avoid grid extension and rather continue off-grid MG operation until the national grid grows more reliable.
For the remaining locations, interconnecting an off-grid MG with the central grid can decrease the MG's operational costs. As the central grid experiences brown- and blackouts, smooth islanding should be guaranteed through the MG control system, and capacity building within the utility infrastructure should be ensured.
Assuming that grid extension can not be avoided and a high reliability of service is required, the MG would have to stay in operation. To give MG operators the chance to connect to the central grid without them having to fear, that cheap central grid electricity destroys their business plans, policies have to be in place ensuring system feasibility. This could encourage MG operators to both implement und continue on-grid operation.

4.7. Scenario 3: Potential of post-interconnection options for MG operation

In Scenario 3, a multitude of post-interconnection operation scenarios are be evaluated. With the increasing number of system architectures, some abbreviations are defined:

- Central grid (CG)
- Off-grid micro grid (Off-MG)
- Micro grid designed for off-grid operation, connected to central grid for consumption (Off-MG-C)
- Micro grid designed for off-grid operation, connected to central grid for consumption and feed-in (Off-MG-CF)
- Micro grid designed for on-grid operation, connected to central grid for consumption (On-MG-C)
- Micro grid designed for on-grid operation, connected to central grid for consumption and feed-in (On-MG-CF)
- Small power producer (SPP)
- Small power distributor (SPD)
- Buy-off of the residual value of the MG when the central grid arrives (reimbursement)
- Unplanned termination of MG when central grid arrives (abandonment)

When assessing the potential of these post-interconnection options, it is essential to consider the perspective and intentions of the stakeholders. Here, the most important stakeholders are the MG operators, intent to keep their projects profitable, and electrification planners pushing for universal electrification of the people at lowest costs.

4.7.1. Results

The interconnection options of the project site *nesp 3670* are evaluated in detail. The effect of on-grid optimization, ie. design adaptation, is described. Then, options to meet both reliable and unreliable national grid interconnection are presented.

Detailed assessment of project site *nesp 3670*. To identify possible design adaptations of the MG supplying *nesp 3670* at to grid arrival, on-grid operation was optimized assuming the same base year. In case of reliable supply, this can decrease the LCOE from 44.3 (Off-MG-C) to 41.3 USDct/kWh (On-MG-C). Allowing feed-in with a bi-directional inverter also shows decreased costs of 43.5 USDct/kWh (On-MG-CF) compared to 46.4 USDct/kWh (Off-MG-CF). On-grid optimization results in no installed PV, inverter or storage capacities, while the generator, by definition being sized to peak demand, makes up a fifth of the system costs even though left unused.
If the MG connects to an unreliable grid, the system costs increase. On-grid optimization of operation dampen this to an LCOE of 49.8 (On-MG-C) and 52.0 USDct/kWh (On-MG-CF). PV capacity decreases from 36.5 kWp to about 22 kWp and storage capacity drops from 10 to 1 kWh (5 to 0.5 kW), leading to an increased fuel consumption from 106 to 127,000 l, while consumption from the grid also increases from 60 to 69 MWh/a for On-MG-C and On-MG-CF.
Considering reliable grid arrival after 5 years, continuing Off-MG operation as Off-MG-C, Off-MG-CF, On-MG-C or On-MG-CF, from a global perspective, would not change the operation costs of 43 to 45 USDct/kWh. From the MG operator perspective, not including interconnection costs, grid arrival would decrease MG operation costs down to 36 to 38 USDct/kWh for the whole operating period. Abandonment, SPP and SPD arrival would force high LCOE of 55.8 to 63.0 USDct/kWh, while reimbursement would haven an LCOE of 37.9 USDct/kWh. None of these post-interconnection options would be cheaper than sole supply through the national grid with 17.4 USDct/kWh (CG).
An unreliable grid would increase the costs of the interconnected system from both MG operator's and global perspective. The global costs of the grid-tied systems drop less significantly from 47.2 (Off-MG-C) to 47.0 USDct/kWh (On-MG-C) and from 48.2 (Off-MG-CF) to 48.0 USDct/kWh (On-MG-CF). From both perspectives, transforming into an SPP or SPD would increase the LCOE compared to an arriving reliable grid. If further operation is not possible, the MG operator would have to be reimbursed with 116.3 kUSD including revenue compensation or would face abandonment costs of 85.7 kUSD. This would lead to global supply costs of 48.9 USDct/kWh in case the arriving grid was reliable and 57.4 USDct/kWh in case it was unreliable, if the costs were distributed over 20 years of project site supply.

On-grid Micro grid optimization. For all cases, optimizing the off-grid MG for on-grid operation results in no capacities of PV and storage to be implemented if the grid is reliable. The diesel generator is, per definition, implemented but left unused. If the grid is unreliable, PV capacities decrease by about 30 %, while both storage power and capacity decrease by about 60 % from their original capacities.
Comparing the design options assuming the same base year, MG design optimized for on-grid operation can save up to 3 USDct/kWh on average when accessing a reliable grid. With an unreliable grid, the cost reductions are minor (see Table 4.7).

Table 4.7.: *Performance of micro grids optimized for on-grid operation, same base year, LCOE in USDct/kWh*

	CG	Off-MG	Off-MG-C	Off-MG-CF	On-MG-C	On-MG-CF
reliable	23.0	42.9	33.5	35.4	30.6	32.8
unreliable	33.0	42.9	39.7	41.7	39.4	41.6

Interconnection with a reliable national grid after 5 years. The average performance of each of the interconnection options is summarized in Table 4.8. On average, continuing standalone off-grid MG operation (Off-MG) is more expensive, both from MG operator's and global perspective , than connecting the MG and continuing its operation of-grid (42.9 USDct/kWh). The MG operator can save a margin of 7 USDct/kWh on average through decreasing fuel expenditures after grid interconnection, resulting in an LCOE of 35.7 USDct/kWh (Off-MG-C). Allowing feed-in into the grid (Off-MG-CF) increases the LCOE. Optimizing on-grid operation can decrease the LCOE by about 1 USDct/kWh, disregarding the annuities of not utilized off-grid MG assets. Transforming into an SPP and selling the distribution grid would increase the LCOE relative to a five year long operating period of the off-grid MG to 53.1 USDct/kWh from an operator's perspective, whereas transforming into a SPD would increase it to 59.9 USDct/kWh. Abandonment would increase the operation costs to 60.1 USDct/kWh, while reimbursement would decrease the system's LCOE to 36.4 USDct/kWh.
In comparison to that, from an electrification planner's perspective, both reimbursement and SPD have the similar global costs of around 39.8 USDct/kWh. Transforming into a SPP is a slightly better option with global costs of 38.9 USDct/kWh. Abandonment would heed the same costs as continued off-grid operation.
The NPV of MG reimbursement costs including one year's worth of revenue, if the MGs operated for after 5 years off-grid and if all MG would be eligible, would add up to 111.4 million USD, with an average of 204.9 kUSD per off-grid MG. If only reimbursing the distribution grid, an average of 46.6 kUSD would need to be paid, with a total of 25.4 million USD.
Without no appropriate policies, the MG operators would face 149.2 kUSD abandonment costs on average (1.2 kUSD/kW), resulting in a total of 81.2 million USD stranded assets.

Interconnection with a unreliable national grid after 5 years. Compared to reliable grid, post-interconnection costs tend to be higher in case of an unreliable grid. The margin between the LCOE from the MG operator's and global perspective barely change for Off-MG-C, Off-MG-CF, On-MG-C, On-MG-CF and increase by 3 USDct/kWh on average compared to reliable grid interconnection. From a global perspective, Off-MG-C and On-MG-C are the least-cost reliable electricity supply solutions with 41.4 and 41.3 USDct/kWh respectively.
The costs of reimbursement and abandonment are identical to a reliable grid from a MG perspective, while SPP and SPD appear more expensive. From an electrification planners point of view, the unreliable national grid increases the LCOE of SPP to 46.0 USDct/kWh. SPD and reimbursement costs increase to 46.6 USDct/kWh. Abandonment is most expensive with an LCOE of 50.5 USDct/kWh. A comparison of both perspectives can be found in Table 4.8.

Table 4.8.: *Potential of post-interconnection options, from MG operator's and global perspective*

	Reliable central grid			Unreliable central grid		
	LCOE (USDct/kWh)		Reliability	LCOE (USDct/kWh)		Reliability
	MG operator	global	(%)	MG operator	global	(%)
CG*	16.3	23	100.0**	21.8	33	60.2**
Off-MG	42.9	42.9	100.0	42.9	42.9	100.0
Off-MG-C	35.7	38.7	100.0	38.4	41.4	100.0
Off-MG-CF	36.5	39.5	100.0	39.3	42.3	100.0
On-MG-C	34.4	37.4	100.0	38.3	41.3	100.0
On-MG-CF	35.4	38.4	100.0	39.3	42.3	100.0
SPP	53.1	38.9	100.0	53.8	46.0	82.3
SPD	59.9	39.7	100.0	60.0	46.6	82.3
Reimbursement	36.4	39.8	100.0	36.4	46.6	82.3
Abandonment	60.1	42.9	100.0	60.1	50.5	82.3

Average values considering all project locations
**) *From time of grid arrival, no electricity supply in first 5 years*
*) *Electrification trough CG, no MG in place at grid arrival*

4.7.2. Discussion

The effect of MG design adaptation for on-grid operation is dependent on the reliability of the arriving grid. The potential of different post-interconnection scenarios is presented for the arrival of both a reliable and unreliable central grid. Both the MG operators and global perspective are considered. The average costs of the interconnection options, based on all project sites, are discussed.

On-grid Micro grid optimization. A MG designed for off-grid implementation is likely not to display optimal on-grid operation. The central grid electricity price might be lower than the diesel generator's marginal costs and feed-in could make renewable sources more viable. As such, on-grid capacities were optimized with the cases On-MG-C and On-MG-CF, considering the same base year. As the MG designed based on its on-grid operation would still be required to operate off-grid in its first years of operation, it has to be ensured that it is able to do so. As the diesel generator is per definition sized to peak demand, this requirement is fulfilled.
A MG consuming from the central grid can benefit from cheap electricity prices of the utility and replaces all diesel generation completely if the grid is available (see Figure A.1). It can also be observed that neither PV or storage capacities are further to be installed on-site if the MG is connected to a national grid. If not to ensure backup, the diesel generator would not have be installed. It's forced installation however influences the LCOE drastically. If an MG is optimized after grid arrival, it should be considered to relocate all assets, as they otherwise have to be abandoned. The costs of on-grid MG in the following paragraphs do not include the annuities of these assets, i.e. assumes their relocation.

In case of unreliable grid supply, the decision to follow the NESP study in regards to peak-demand sized generators might hide the actual potential of renewable sources. At the same time, the assumed feed-in tariff of 5 USDct/kWh is much too low to encourage additional PV capacities in MG optimized for on-grid operation, as marginal generation costs of solar generation amount to 13.4 USDct/kWh based on PV panel annuity alone. As such, the national FIT for utility-sized solar generation with 17 USDct/kWh is appropriate. If MG were to be pushed to higher renewable shares, either a minimal renewable share would have to be required as per legislation or subsidies offered for their integration.

Interconnection with a reliable national grid after 5 years. When interconnecting an off-grid MG after 5 years of operation with a reliable central grid, the project site requires a re-evaluation of its future operation options. Two perspectives have to be compared: The MG operators perspective, including all MG investments and energy expenditures but no central grid extension costs, and on the other hand the global costs, i.e. the costs to be taken into account during electrification planning.
In the following, all analysed post-interconnection options are evaluated based on their average costs, while their distribution is displayed in Figure A.2.

- **CG.** From the MG operator perspective, the costs connected to central grid supply only cover distribution grid and electricity expenditure costs (16.3 USDct/kWh). From a global, electrification planning point of view, central grid extension costs also account for extension and transformer stations, resulting in an LCOE of 23.0 USDct/kWh.
  Ideally, these costs should be covered by the utility's electricity tariff, but many countries subsidize electricity to make it affordable to their population. This can result in very low electricity prices that make it harder for MG to compete However, choosing CG for electrification would deny customers electricity access for an extended amount of time while a MG could be implemented in a timely manner.
- **Continued MG operation (Off-MG, Off-MG-C, Off-MG-CF, On-MG-C, On-MG-CF).** Continuing operation of any off-grid MG after interconnection is more expensive than electrification with CG. To connect the Off-MG to a reliable central grid saves about 7 USDct/kWh and, thus, should be preferred when the grid arrives. If the MG operation is optimized for on-grid dispatch (On-MG-C) the costs can further be reduced. Discontinued assets are relocated and do not adversely influence the LCOE. Upgrading an off-grid MG for on-grid operation, regarding both installed capacities and dispatch-algorithms, should be evaluated on a case-by-case basis.
  The LCOE from a MG operator's perspective differ from the global LCOE by about 3 USDct/kWh. Compared to the other options however, continued MG operation (Off-MG-C, On-MG-C) appears more favourable from the global perspective and as it has lower LCOE than than SPP, SPD, reimbursement and abandonment.
- **SPP.** Transforming the MG into an SPP is one of the less-favourable outcomes for a MG operator. While the distribution grid would be reimbursed by the utility, other assets would be abandoned. These costs are not met with feed-in revenues, as low FIT could not even cover the costs of PV operation. Distributing off-grid MG costs over its 5 year operating period reveals an LCOE of 53.1 USDct/kWh. From a global perspective, the costs would be much lower with 38.9 USDct/kWh, as they are distributed over the whole project time.

- **SPD.** Together with abandonment, transforming the Off-MG into an SPD is the least favorable option for the MG operator. Apart from the distribution grid, which is further operated, all other components are abandoned. These costs are internalized for the MG operator, distributed over the 5 years that the Off-MG is operating (59.9 USDct/kWh). This makes the SPD more viable from a global perspective that considers the whole project duration (39.7 USDct/kWh). With a profit margin of only 2 %, sales can not outweigh neither abandonment costs nor continued distribution grid operation costs. Relocation of the assets could decrease these costs.
  The effect of higher profit margins, subsidies covering the distribution margin and project site specific tariffs should be evaluated in the future to make the SPD concept viable in Nigeria.
- **Abandonment.** If an Off-MG is abandoned, the costs for the MG operator are the highest and add up to an LCOE of 60.1 USDct/kWh when distributed over the 5 year period. If the MG operator is not able to gather these revenues per unit electricity sold during time of operation, it will generate high losses at time of grid arrival.
  The global costs are lower, as they are distributed over the whole time period of 20 a (42.9 USDct/kWh). As such, abandonment is as expensive per unit supplied as continued operation of Off-MG from an electrification planning point of view.
- **Reimbursement.** If the government or utility would be required to reimburse each Off-MG that is connected to the central grid, termination of the MG would be an option for most operators as it decreases the LCOE almost to the level of continued operation without harbouring the insecurities connected to it. These insecurities concentrate on the future revenue stream that might not be guaranteed by sufficiently high tariffs or subsidies, making it risky for MG operators to continue operation. From a global perspective, reimbursement is one of the costlier options and and should be avoided.

Considering the costs of all post-interconnection options, the MG operator would prefer to either continue MG operation on-grid, if continued operation would be subsidized, and profit from low electricity prices or be reimbursed and terminate operation. If a MG project is implemented and the operator fears grid arrival, tariffs might be set comparably high to cover the risk of stranded assets. Governments might want to limit the volatility of tariff-setting to make electricity universally available and affordable. If it does, however, set a tariff cap, subsidies covering the generation margin of off-grid MG should also be part of these regulations, as it otherwise would inhibit unprofitable sites from being electrified.

From a global perspective, electrification through CG is the least-cost option. At the same time this should not be universally favoured, as it would delay electrification for many consumers. Continued operation of the implemented Off-MG as Off-MG-C, or an refitting to On-MG-C, proves to be the cheapest electrification option. Reimbursement would be more expensive.

The margin between both MG operator's and electrification planner's perspective should be the focus of governmental policies; balancing out both perspectives to find least-cost electrification pathways without discouraging MG operators from implementing their grids. In total, it might be favourable for governments to subsidize MG operation than to pay out reimbursements covering residual values and a year's worth of revenues.

Interconnection with a unreliable national grid after 5 years. In the paragraph above, the post-interconnection options of an Off-MG connecting to a reliable grid after 5 years of operation were assessed. However, in reality, the central grid might have brown- and blackout issues, which could change the LCOE of each of the options. Therefore, in the following, the post-interconnection options of MG after the arrival of an unreliable grid is evaluated, based on their average costs. The distribution of LCOE is displayed in Figure A.3. The number of blackout occurrences is assumed to remain as it is today.

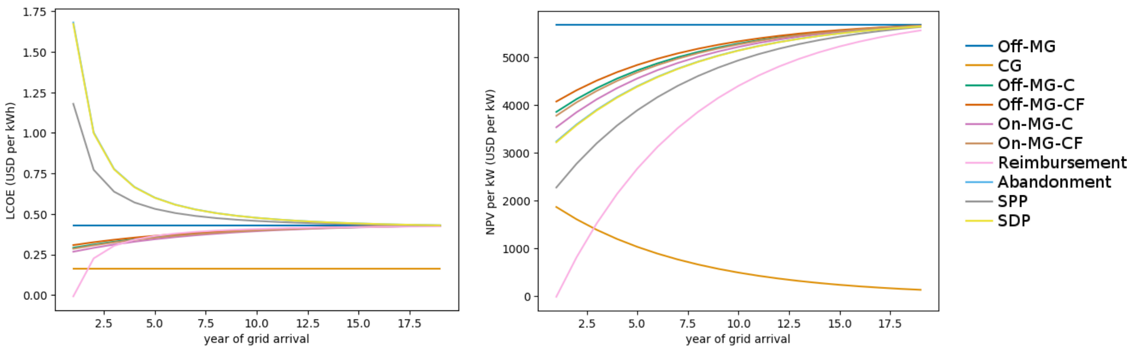
- **CG.** The central grid is not able to provide electricity reliably and, thus, has, compared to a reliable grid, increased global costs of 33.0 USDct/kWh per supplied unit of electricity. The margin between the costs of from MG operator's and global perspective increases, as central grid extension costs have to be distributed over less units electricity supplied. From both perspectives, electrification through CG would be the least-cost option - but would not be able to fulfill the promises of reliable electrification for the consumers, as it can only supply about 60 % if the demanded electricity. The decision of whether or not to electrify a community with the CG should therefore also take into account the effects of unreliable supply of the community.
- **Continued MG operation (Off-MG, Off-MG-C, Off-MG-CF, On-MG-C, On-MG-CF).** The costs of continued operation of grid-connected MG increase for each option by 3 USDct/kWh compared to a reliable grid. As the unreliable central grid can not replace diesel generation to the amount that an reliable grid could have, the cost difference between off-grid and on-grid operation decrease. Refitting of the MGs can only decrease the costs minorly.
- **SPP.** Transforming the off-grid MG increases the LCOE, compared to reliable grid interconnecteion, from a MG operator's point of view to 53.8 USDct/kWh. This is based on the simplification that the SPP is able to sell a percentage equal to to the central grids reliability of its generated electricity to the utility. A higher share is only possible if the local grid has the ability to island from the central grid and continue to distribute electricity in case of an outage. From the global perspective, the costs also increase as they are distributed over less successfully supplied demand.
- **SPD.** Transformed into an SPD, the previous generation capacities of the MG are abandoned. As such, the SPD is dependent on the central grid - and it's lacking ability to cover the community's demand increases the costs both from the operator's and global perspective.
- **Reimbursement.** Reimbursement is the best option for a MG operator and promises lower costs than continued operation connected to the central grid (36.4 USDct/kWh). At the same time, it is with an LCOE of 46.6 USDct/kWh more expensive from a global perspective than continuing MG operation.
- **Abandonment.** Termination of the MG at central grid arrival continues to be the most expensive option for MG operators and electrification planners alike.

The interconnection options of SPP, SPD, reimbursement and abandonment were viable options when connecting an off-grid MG to a reliable central grid and did not endanger the supply reliability of the communities.

In case an unreliable grid arrives, however, these options deprive the communities of the reliability they previously experienced with electricity supply from an off-grid MG. This can lead to consumer dissatisfaction, welfare reduction and revenue losses of companies. Some MG operators therefore might decide to operate in parallel to an unreliable central grid, if the expected revenues for backup electricity are sufficient to keep the MG in operation.
The assessment reveals that continued MG operation can benefit electrification efforts from a global perspective - each of the MG interconnection options, especially Off-MG-C and On-MG-C, are cheaper than SPP, SPD, reimbursement and abandonment while at the same time ensuring reliable supply of the communities.
Under this premise, the policy of general reimbursement at grid arrival should be questioned. Instead, the option of subsidized on-grid operation of previous Off-MG should be introduced as an alternative to reimbursement into regulations. As a positive side effect, this would ensure that sufficient generation capacities are in place to supply the new connections to the central grid. This could slow down necessary implementation rates of utility-sized electricity plants while potentially increasing the renewable share of electricity generation. It could also help to avoid increased capacity and grid overuse resulting in an increased amount of outages.

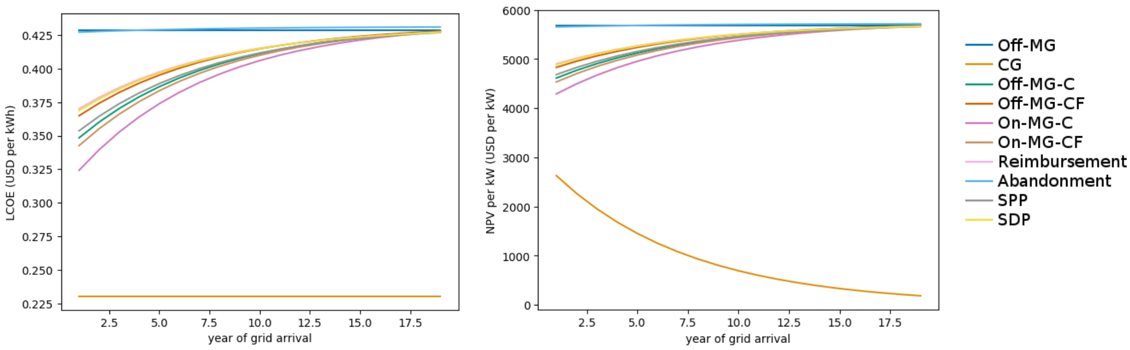
Dependency time of grid arrival. The post-interconnection options above are both evaluated for an expected grid arrival after 5 years. From the MG operator's perspective, the interconnection can both decrease LCOE, as for on-grid MG, or increase them in case of abandonment. The time of arrival is the main factor deciding upon the cost margin that is avoided or added. Therefore, a sensitivity analysis regarding grid arrival time was performed for each interconnection scenario and perspective. Here, we concentrate on the MG operator's perspective; the resulting trends of LCOE and NPV are visualized in Figure 4.8.
From a MG operators point of view, having to transform into an SPD or abandon all assets is increasingly expensive the earlier the grid arrives. The NPV in case of early grid arrival does appear lower than the NPV of an Off-MG due to fuel expenditures avoided, but are subsequently distributed over low total electricity supply, resulting in very high LCOE. The LCOE can reach up to over 1 USDct/kWh if the Off-MG is interconnected in the first two years of operation. Transforming into an SPP does save some costs as the distribution grid is reimbursed, but still results in high LCOE. The losses in terms of LCOE decrease exponentially for abandonment, SPD and SPP dependent on the time of grid arrival.
Continued MG operation is, apart from reimbursement, the best option. However, central for continued grid-connected operation is the operators ability to set costs covering tariffs or receive subsidies. If the MG tariff is lower than the LCOE resulting from grid arrival, the MG operator will experience revenue losses that endanger the MG business case. Through interconnection, operation of the Off-MG can decrease NPV and LCOE notably. If continued operation was ensured, it would be most beneficial for an Off-MG to experience grid interconnection early on.
Reimbursement of the MG is especially beneficial in the first years of operation, as a large share of the investment costs is reimbursed, few fuel expenditures had to be paid and, also because high future fuel expenditures are avoided, the present value of reimbursed lost revenue is high. As such, if the grid arrives after one year operation, the MG operator terminates MG operation without having to cover any of the costs (LCOE of approx. 0 USDct/kWh).

All interconnection options close in on the original Off-MG value of LCOE and NPV asymptotically with increasing year of interconnection. Interconnection with a unreliable option decreases the margin saved by on-grid operation of the Off-MG.
From a global perspective, the costs of electrification are more expensive the later grid arrival takes place. Continuing off-grid MG operation after refitting appears to be the cheapest option, while reimbursement is more comparably expensive. Abandonment is least favorable (see Figure 4.9). If the arriving gird, however, is unreliable, early interconnection is increasingly expensive for early grid arrival in case of abandonment, SPP, SPD and reimbursement.
From a MG operators perspective, tendencies of the post-interconnection option's potentials basely change if the grid arriving is unreliable.
The dependency of LCOE and NPV in case of unreliable grid arrival from both MG operator's and global perspective are visualized in Figures A.4 and A.5 in the appendix.



(a) *LCOE* **(b)** *NPV/kW* **(c)** *Legend*

Figure 4.8.: *Time of grid arrival and costs of post-interconnection options, MG operator, reliable*



(a) *LCOE* **(b)** *NPV/kW* **(c)** *Legend*

Figure 4.9.: *Time of grid arrival and costs of post-interconnection options, global, reliable*

5. Summary of results and discussion

Within this chapter, the results of the case study's three scenarios and their interpretation are contextualized. A summary of the results is presented in Section 5.1. The following Section 5.2 describes the ability of this thesis' results to be generalized. In Section 5.3 the limitations of the input data, used methodology and outputs are summarized and translated into issues requiring future research.

5.1. Summary of case study results

The case study is based upon an electrification plan for the Nigeria's Plateau State developed within the research study *Nigeria Rural Electrification Plans* in the scope of the *Nigerian Energy Support Programme* (NESP study). The 544 identified clusters were evaluated in terms of optimal off-grid capacities (scenario 1), competitiveness with the central grid (scenario 2) and potential of post-interconnection operation options (scenario 3). Reliability issues of the central grid due to outages were taken into account.

Scenario 1 - Simulation tool validation. The simulation results show an expected deviation from the optimized capacities of the NESP study's rule-based algorithm. Even though the electrification stages can not be clearly distinguished, trends can be identified that support the study's distinction into different stages, including factors like distance from the grid, peak demand and expected net present value (NPV) and Levelized Costs of Electricity (LCOE). As such, the simulation tool is, with its intrinsic limitations, validated for this study's purposes.

Scenario 2 - On-grid performance of off-grid micro grids. The performance of the off-grid micro grid (Off-MG), whose capacities were optimized in Scenario 1, interconnected with both a reliable and unreliable grid are evaluated.
They can confirm the paradigm that micro grid (MG) interconnecting with a reliable grid are likely to be terminated if no appropriate policies are in place. Marginal diesel generation costs are higher than the central grid electricity price, leading to termination of diesel generator utilization and allowing the MG to have lower LCOE than in off-grid operation. On the other hand, the Feed-In Tariff (FIT) assumed in this study can not cover marginal photovoltaic (PV) generation costs, making interconnecting off-grid MG and enabling their solar feed-in into the grid an infeasible interconnection option.
In an unreliable grid, the margin between central grid and on-grid MG decreases. The MG can ensure reliable supply for only an additional fraction of the central grid's LCOE. It is, however, still more expensive than a national grid's supply of 60 % reliability, and therefore is in need for subsidization.

Scenario 3 - Potential of post-interconnection options for MG operation. The interconnection options of a formerly off-grid operating MG with a reliable as well as an unreliable central grid arriving after 5 years are evaluated. Both MG operator's and global, electrification planning perspectives are considered.
For reliable grids, the central grid (CG) is the cheapest option in most cases. The MG operator would prefer continued operation over reimbursement. Reimbursement can have higher global costs than continued subsidized on-grid operation of previously off-grid MG, especially if the grid's operation strategy is adapted to on-grid operation and assets are relocated to new project sites. Transforming into an small power distributor (SPD) abandoning all assets or small power producer (SPP) selling off the distribution grid and continuing PV panel operation are not profitable assuming a 2 % profit margin for SPD and a FIT of 5 USDct/kWh, which can not cover marginal generation costs. Abandonment is, together with continued off-grid operation, the option with the highest costs from a global perspective.
In case of an unreliable grid, continuing the operation of the Off-MG as an on-grid MG is the cheapest option from a global perspective. However, reimbursement payments encourage MG operators to terminate their operation and leave communities with unreliable grid supply. Therefore, electrification planners should consider to propose subsidy plans for MG interconnecting with an unreliable MG.

5.2. Implications and transferability

With the scenarios analysed above, this study addressed some of the research questions mentioned in [2] and [8]: The post-interconnection options of PV-hybrid MGs connected to both a reliable and an unreliable central grid is evaluated. With input parameters specific for the case study's geographical location Nigeria, the results can be scaled nation-wide. They are not dependent on the distance from the current national grid and therefore do not overproportionally disadvantage rural regions. However, it is likely that blackout occurrences experience local variations, especially on the fringes of the national grid. The limitation to settlements of over 50 kW demand was a necessity to allow a tool validation through the NESP study.
Some results should also be considered when assessing post-interconnection options of Off-MG in other countries. It has to be considered, though, that Nigeria has the highest rate of outages amongst other sub-Saharan countries [49, 26f], and apart from the general tendencies the assessment should be adapted to local conditions.
According to [32], policies concerning MG transformation into SPP or SPD at grid arrival or reimbursement have already been addressed. If the countries' national electricity network, however, is unreliable, the interconnection options offered to MG operators should be reconsidered as they leave people vulnerable to unreliable supply. From a global perspective, reimbursement costs might have to be questioned to be the only policy motivating MG planners and investors to implement MG close to central grid infrastructure. Instead, subsidies for on-grid MG operation, covering generation margins, as in Cambodia [8, p. xii], or guaranteed revenue-generating FIT should be considered.
These policy adaptations could help to push a paradigm-shift of electrification planning towards an integrated and interconnected view of centralized and decentralized electrification pathways. For the electrification of a project location, the question should not be, whether or not to implement a grid extension or micro grid, „[...] but deciding how and when off-grid investments complement grid-extension projects“ [16, p. 4].

5.3. Limitations and research needed

The case study's results have, in the basic outline, the potential to be generalized for electrification planning in Nigeria. The simulation tool developed is applicable to other case studies as well. However, it has to be considered that the methodology includes a number of simplifications that can limit generalization or accuracy. The main limitations, mostly already discussed in other parts of this study, are presented in the following paragraphs.

Input data of NESP study. Data scarcity influences spatial electrification planning in NESP study. Infrastructure and census data sets can be patchy and are combined with Geographic Information System (GIS) data to identify settlement clusters. Excluding clusters with less than 50 kW from the electrification planning process is to some extent arbitrary.

Load profiles. Load profile estimation is a delicate process of central importance for the techno-economic evaluation of supply solutions. The load profiles used in this study were provided by the NESP study and, as such, elaborate: They take into account the site-specific economic situation, load profiles for different demand-levels of private consumers as well as agriculture, productive and business users, whose number is determined per number of customers. Seasonality, hourly as well as day-to-day variance are introduced to display the variabilities of demand. Still, being a study evaluating a great number of project locations, the profiles are generic. When optimizing a single project location, the demand profile should be tested again not to over- or underestimate the demand, which would endanger sustainable system operation.

Distance from central grid. Instead of using the current distance from the central grid, the additional branch distances of the project locations, i.e. their distance to the grid branches to be implemented in the future, were estimated and used as an input to calculate grid extension costs. As such, comparing all project locations to the central grid electricity costs ignores the time until grid arrival and compares MG and central grid as if they were solutions that could provide services in comparable time frames. The potential of the national grid to provide electricity to the study's project locations is therefore overestimated. This could also be a reason for the difficulty to clearly distinguish the electrification stages defined. Additionally, a deviation of central grid extension costs in this study (44 million USD) compared to NESP study (87 million USD) has to be noted. They are likely to be caused by a more detailed algorithm used in the GIS-based analysis used in the NESP study. Additionally, grid extension projects could be defined differently in the NESP study, increasing fix project costs. This further decreases the costs of central grid extension in this study.

Linear optimization with perfect forecast. As shown in scenario 1, the linear optimization can lead to low capacities and overly ideal charging behaviour of batteries. Other tools use rule-based algorithms to optimize operation, which might be closer to actual MG operation. This also influences capacity optimization. With perfect foresight, the actual system costs and generation might be underestimated.

Component models. Using the Open Energy Modelling Framework (oemof), the component models used needed to be simplified and linearized. As such, diesel generator and charging efficiency are constant, as are inverter efficiencies. The diesel generator additionally is modelled without minimal loading. This is an appropriate and necessary level of simplification for the evaluation of a high number of project sites. However, it can not replace detailed MG design on a case-by-case basis and should only be perceived as a first capacity estimation. When deciding for a electrification of a single project location, it might be beneficial to either perform sensitivity analysis of central parameters to find a stable optimum configuration.

Blackout frequency and duration. The blackout randomization algorithm results in an overestimated grid reliability, while the average duration of blackouts increased and frequency decreased compared to the input values. As such, the actual national grid performance and capabilities vary from the simulated ones. In the context of a batch-analysis of a great number of locations, this can be accepted, as every location is influenced equally. To derive explicit policy recommendations, the algorithm should be improved to mirror actual behaviour. On the other hand, as outage patterns are specific for each location and are increased at the fringes of the grid, the project locations should ideally be attributed with a specific grid availability time series. Alternatively, a sensitivity analysis could uncover the influence of blackout duration and frequency on MG interconnection options.

Value of reliable supply. The LCOE of unreliable supply is calculated from the system's NPV and amount of supplied electricity. As electricity expenditures are avoided when electricity is not supplied, this can lead to an - even if increased compared to reliable grid - relatively low electricity cost per unit. Comparing supply systems based on their LCOE alone therefore can leave an distorted impression. To take into account the detrimental effects of unreliable supply on welfare and business revenues, it should be considered to put a price on supply shortage in form of a penalty, e.g. mirroring revenue loss. This could allow the comparison of systems with different reliabilities.

Central grid supply. The dominance of electricity provision through the national grid is based on very low electricity tariffs. Necessary capacity building efforts require high investments, which, potentially, could be translated into higher electricity tariffs. Here, it was assumed that the electricity price stays at 8 USDct/kWh. If this changes, other options might appear more favourable.
Connected to this, further capacity building could improve national grid reliability. On the other hand, an increased number of connections and, thus, demand, could also lead to decreased reliability. This forecast would have change the simulation results presented here. Apart from forecasting these effects on grid reliability, it should also be considered to evaluate the role that MG can play to decrease the stress on capacity building.

Time of grid arrival. The performance of post-interconnection options was arbitrarily evaluated based on grid arrival after 5 years of operation. However, as displayed in Figures 4.8, the costs are heavily dependent on the time of arrival. Potentially, the current grid reliability de- or increases until the grid arrives.

To forecast actual costs of reimbursement and necessary revenues, the project locations of the case study should be attributed a site-specific grid arrival time depending on the stage in which they are interconnected with the national grid.

As described above, a number of limitations are connected to the simulation results presented here. Some limit the detail of the study, some are likely to change the simulation results altogether. The issue of post-interconnection options of MG projects sites facing grid arrival needs to be further researched. Three issues can be pointed out that need special attention in proceeding research:

1. How do time of grid arrival, increased grid reliability and the potential of interconnection options interplay?
2. How can the value of reliable electricity supply be included in electrification planning and help to find suitable supply solutions?
3. How should regulations be designed to offer well-placed reimbursements when continued operation of micro grid interconnected with a reliable central grid is not further profitable from a global perspective, but at the same time keep them in operation (i.e. with subsidies) in case of grid reliability issues?

6. Conclusion

With the general recognized need to achieve Sustainable Development Goal (SDG) 7 and push development in the field of electricity access, micro grids (MGs) take a special place in subsequent electrification plans. They often promise a more timely provision of electricity compared to grid extension and can be cheaper than other off-grid solutions, e.g. SHS. However, their implementation is slowed down by a number of barriers, including financing and standardization, but also due to regulatory issues, especially concerning future MG interconnection with a national grid. As such, future grid arrival often appears as a threat to MG operation and can result in projects not being realized.
In general, however, this is not a technological problem and there are positive examples of regulatory frameworks meeting the needs of MG operators. On the other hand, the real-life issue of MG connecting to weak national grids has been long overlooked, comparing MG projects to future grid extensions with high reliability. This possibly underestimates the benefit of MG as sources of reliable electricity supply and their role to buffer additional stress on the national power grid infrastructure through new connections and increasing demand.
This study aims to shed some light into off-grid MG's interconnection with both reliable and unreliable central grids by answering three research questions.

How can an off-grid micro grid and its different post-interconnection options be simulated in an integrated manner? To optimize off-grid MGs and their possible post-interconnection options, a python-based simulation tool using the open-source library Open Energy Modelling Framework (oemof) is created. It allows the simulation of a batch of project locations and can also take into account grid outages. The tool is then applied to a case study, which is based upon an electrification plan for Nigeria's Plateau State, and optimizes MG for 544 project sites of over 50 kW capacity. The tool is validated through this application and shows that project locations with high peak demand and close to the future central grid have especially low Levelized Costs of Electricity (LCOE). They are preferred MG project sites.

Can the paradigm be confirmed, that off-grid micro grids are abandoned when a reliable or unreliable national grid arrives? When facing grid arrival, these above optimized off-grid MG have to compete with much cheaper central grid electricity supply. While the connection to a reliable grid can decrease operation costs by replacing diesel generation, most locations could not compete with the national grid's electricity costs. These project sites are in danger of being abandoned.
In case of an unreliable grid of 60 % reliability could be extended to the project site, approximately 18 % of the MG could supply the communities for lower LCOE off-grid. 36 % of the project locations would experience increased LCOE at national grid arrival. Termination the MG that have higher LCOE than the national grid would leave communities vulnerable to the national grid's unreliable supply.

What are the different post-interconnection options of off-grid micro grids to a reliable or an unreliable national grid and what are their potentials? A number of post-interconnection options of the interconnecting off-grid micro grids were evaluated, including: on-grid operation of the micro grid designed for off-grid supply, capacity adaptation (refitting), transformation into small power producer (SPP) and small power distributor (SPD) as well as reimbursement and abandonment. As a MG operator would take other costs into account than electrification planners, both perspectives are evaluated. The national grid is assumed to arrive after five years of operation.
If the arriving grid is reliable, the MG operator's costs decrease through interconnection. They are, however, still more expensive than national grid electricity. The operator would prefer to continue on-grid operation, if subsidies were provided, or receive reimbursement for the residual value of the MG's assets and a year's worth of revenues. With the assumed Feed-In Tariff (FIT) and cheap national grid electricity, adapting the design to on-grid operation can decrease costs minorly. Abandonment would be by far the most expensive outcome with costs of about 1.2 kUSD/kW, and SPP as well as SPD could not ensure necessary revenues. From an electrification planner's perspective, on-grid operation would be less expensive than reimbursement as well. On average, a MG would require a reimbursement of 205 kUSD.
When interconnecting with an unreliable national grid, reimbursement becomes more favourable for the MG operator. However, from an electrification planner's perspective, continued on-grid operation would be favourable. Therefore, electrification planners should define regulations to make continued operation of grid-interconnected MG more attractive, as they can promise reliable supply while present-day central grid supply would only be able to meet 60 % of the demanded electricity.

While the findings of this study confirm the paradigm of MG termination after the arrival of an reliable grid, if no subsidies are provided for on-grid operation, they question the paradigm in case of an arriving unreliable national grid. Policy makers should re-evaluate whether general MG reimbursement should be the only option after grid arrival or if new subsidies can be introduced that support the added value of electricity supply reliability through MG operation. For that, further research should first evaluate general trends connected to the financial viability of interconnection options regarding grid arrival time and central grid reliability.

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A. Appendix

This appendix includes

- The Multi-Tier Framework of Electrification (MTF)
- All simulation tool in- and output parameters
- Input parameters according to research study *Nigeria Rural Electrification Plans* in the scope of the *Nigerian Energy Support Programme* (NESP study)
- Equations connected to post-interconnection options
- Box plots on LCOE and net present value (NPV) distribution of post-interconnection options, if grid arrived after 5 years
- Dependency of LCOE and NPV and time of grid arrival in case of unreliably grid supply

As the generated code, input data and data resulting from the simulations is very extensive, it is available in the electronic appendix (CD). This includes:

- Python-Code of the simulation tool
- Standalone scripts pre- and postprocessing input data and results
- All excel-files defining the simulations, as well as csv-files including demand and pv generation time series
- Direct simulation results, ie. system performance indicators calculated by the simulation tool
- Processed simulation results, ie. costs and graphs of post-interconnection options

Table A.1.: *Multi-Tier Framework of Electrification*

Developed by and adapted from [15, 6, tables ES.1-ES.3]

Attributes		Tier 0	Tier 1	Tier 2	Tier 3	Tier 4	Tier 5
Capacity	Power		> 3 W	> 50 W	> 200 W	> 800 W	> 2 kW
	Daily		> 12 Wh/d	> 200 Wh/d	> 1 kW/d	> 3.4 kW/d	> 8.2 kW/d
	Annual		> 4.5 kWh/a	> 73 kWh/a	> 365 kW/a	$> 1{,}250$ kW/a	$> 3{,}000$ kW/a
	(or) Services		Lighting, phone charging	Lighting, fans, TV, phonecharging	Tier 2 and medium-power appliance	Tier 3 and high-power appliance	Tier 4 and very high-power appliance
Duration	Hours per day		> 4 hrs	> 4 hrs	> 8 hrs	> 16 hrs	> 23 hrs
	Evening hours		> 1 hr	> 2 hrs	> 3 hrs	> 4 hrs	> 4 hrs
Reliability						< 14 disruptions per week	< 3 disruptions per week, total duration < 2 hrs
Quality						Voltage fluctuations do not affect appliances	
Affordability					Electricity costs for 365 kWh/a less than 5 % of income		
Legality						Payments to authorized seller	
Health and safety						No past accidents, no high risk in future	

A.1. Parameters of the simulation tool

Table A.2.: *Input parameters of the simulation tool*

blackout duration	hrs
blackout duration std deviation	fraction
blackout frequency	/mth
blackout frequency std deviation	fraction
combustion value fuel	kWh/l
demand ac scaling factor	factor
demand dc scaling factor	factor
distribution grid cost investment	currency
distribution grid cost opex	currency/a
distribution grid lifetime	a
genset batch	kW
genset cost investment	currency/kW
genset cost opex	currency/kW/a
genset cost var	currency/kWh
genset efficiency	factor
genset lifetime	a
genset max loading	fraction
genset min loading	fraction
genset oversize factor	factor
inverter dc ac batch	kW
inverter dc ac cost investment	currency/kW
inverter dc ac cost opex	currency/kW/a
inverter dc ac cost var	currency/kWh
inverter dc ac efficiency	fraction
inverter dc ac lifetime	a
maingrid distance	km
maingrid electricity price	currency/kWh
maingrid extension cost investment	currency/km
maingrid extension cost opex	currency/km/a
maingrid extension lifetime	/km/a
maingrid feedin tariff	currency/kWh
maingrid renewable share	fraction
min renewable share	fraction
pcoupling batch	kW
pcoupling cost investment	currency/kW
pcoupling cost opex	currency/kW/a
pcoupling cost var	currency/kWh
pcoupling efficiency	fraction
pcoupling lifetime	a
pcoupling oversize factor	factor
fuel price	/l
fuel price change annual	p.a.
project cost investment	currency
project cost opex	currency/a
project lifetime	a
pv batch	kWp
pv cost investment	currency/kWp
pv cost opex	currency/kWp/a
pv cost var	currency/kWh

Parameter	Unit
pv lifetime	a
rectifier ac dc batch	kW
rectifier ac dc cost investment	currency/kW
rectifier ac dc cost opex	currency/kW/a
rectifier ac dc cost var	currency/kWh
rectifier ac dc efficiency	fraction
rectifier ac dc lifetime	a
shortage max allowed	fraction
shortage max time step	fraction
shortage penalty costs	currency/kWh
stability limit	fraction
storage batch capacity	kWh
storage batch power	kW
storage capacity cost investment	currency/kWh
storage capacity cost opex	currency/kWh/a
storage capacity lifetime	a
storage cost var	currency/kWh
storage Crate charge	fraction
storage Crate discharge	fraction
storage efficiency charge	fraction
storage efficiency discharge	fraction
storage loss time step	fraction
storage power cost investment	currency/kW
storage power cost opex	currency/kW/a
storage power lifetime	a
storage soc initial	None or factor
storage soc max	fraction
storage soc min	fraction
tax	fraction
wacc	fraction
white noise demand	fraction
white noise pv	fraction
white noise wind	fraction
wind batch	kW
wind cost investment	currency/kW
wind cost opex	currency/kW/a
wind cost var	currency/kWh
wind lifetime	a

Table A.3.: *Output parameters of the simulation tool*

Value	Unit
lcoe	currency/kWh
annuity	currency/a
npv	currency
supply reliability kWh	fraction
res share	fraction
autonomy factor	fraction
total demand annual	kWh
demand peak	kW
total demand supplied annual	kWh
total demand shortage annual	kWh
national grid reliability	ratio
national grid total blackout duration	hrs
national grid number of blackouts	-
capacity pv	kWp
capacity wind	kW
capacity storage	kWh
power storage	kW
capacity genset	kW
capacity pcoupling	kW
consumption fuel annual	l
consumption main grid mg side annual	kWh
feedin main grid mg side annual	kWh
annuity pv	currency/a
annuity storage	currency/a
annuity rectifier ac dc	currency/a
annuity inverter dc ac	currency/a
annuity wind	currency/a
annuity genset	currency/a
annuity pcoupling	currency/a
annuity distribution grid	currency/a
annuity project	currency/a
annuity maingrid extension	currency/a
expenditures fuel annual	currency/a
expenditures main grid consumption annual	currency/a
expenditures shortage annual	currency/a
revenue main grid feedin annual	currency/a
costs pv	currency
costs storage	currency
costs rectifier ac dc	currency
costs inverter dc ac	currency
costs wind	currency
costs genset	currency
costs pcoupling	currency
costs distribution grid	currency
costs project	currency
costs maingrid extension	currency
expenditures fuel total	currency
expenditures main grid consumption total	currency
expenditures shortage total	currency
revenue main grid feedin total	currency
objective value	-
simulation time	s
evaluation time	s

A.2. Case study parameters

Table A.4.: *Demand assumptions of the NESP study, based on table 5.6 and 5.7 in [11, p. 88]*

Electricity demand per consumer type

Consumer		kWh/d
Households	low	0.74
	medium	2.35
	high	5.38
Commercial		3.0
Productive		12.0
Agricultural		5.0
Water pumps		1.0
Schools		3.0
Health	low	15.0
	high	150.0

Ratio of business uses to number of households	
Commercial	1:10
Agriculture	1:20
Productive	1:50

Other parameters	
Connection rate of households	80 %
Day-to-day variability	10 %
Hour-to-hour variability	10 %

Table A.6.: *Input parameters of the NESP study, according to [11]*

Asset	Parameter	Unit	Value
PV	CAPEX	USD/kWp	1,250
	OPEX	USD/kWp/a	25
	Lifetime	a	25
Battery	CAPEX (Capacity)	USD/kWh	250
	CAPEX (Power)	USD/kW	500
	OPEX	USD/kWh/a	6.75
	Lifetime	a	15
	Maximum c-rate	kW/kWh	0.5
	Maximum depth of discharge	%	80
	Charging efficiency	%	97
	Discharging efficiency	%	97
	Number of cycles	-	4,900
	Initial state of charge	%	0
Diesel generator	CAPEX	USD/kW	820
	OPEX (fix)	USD/kW/a	0
	OPEX (var)	USD/kWh	0.05
	Sizing factor	% peak demand	100
	Lifetime	a	10
	Minimal Loading	% of max power	10
	Rotating mass	%	40
	Efficiency @ min loading	%	30
	Efficiency @ max loading	%	35
Distribution grid	Connection costs	USD/customer	400
	Lifetime	%	40
	OPEX	USD	1 % CAPEX
National grid	CAPEX (fix per project)	USD	20,000
	CAPEX (medium voltage grid)	USD/km	20,000
	CAPEX (transformer)	USD/kW	100
	Transformer oversize factor	% peak demand	150
	Transformers installed per cluster	amount	2
	Electricity price	USD/kWh	0.08
Project development	CAPEX (fix)	USD	20000
	CAPEX (var)	%	0
	Lifetime	a	20
Others	Fuel price	USD/l	0.68
	Annual fuel price change	% p.a.	5
	WACC	%	16

A.3. Economical calculations regarding micro grid interconnection

The post-interconnection options of a MG at grid arrival can be compared based on their NPV and Levelized Costs of Electricity (LCOE). Their calculation shall be explained in the following. It is important to highlight, that no additional simulations are run and evaluated, but solely previously generated data is processed. This includes, explicitly, following input values of off-grid MG optimization and sole main grid supply:

- Annuities of project A_i [USD/a], including each component and other cash flow
- Peak demand $P_{p,dem}$ [kW]
- Annual demand E_{dem} [kWh/a]
- Solar generation at project site (time series) P_{solar} [kWh/h]
- Optimized capacity of photovoltaic (PV) CAP_{pv} and Point of Common Coupling (PCC) CAP_{pcc}
- Time of grid arrival t [a]
- Feed-in tariff for electricity FIT [USD/kWh]
- Main grid electricity price p_{el} [USD/kWh]
- Profit margin r [USD/kWh]
- Reliability in percent to supply demand, both from grid η_{CG} and interconnected solution $\eta_{intercon}$ [-]

From this, the NPV and LCOE for the post-interconnection cases small power producer, small power distributor, reimbursement and abandonment are be calculated. A simpler approach is be used to calculate supply costs of interconnecting a MG optimized for off- and on-grid operation. Difficulties arise in case of a low system reliability of the national grid.

Universal values. A couple of definitions and values are universal for all cases. This includes the discounting factor, capital recovery factor (CRF) and the costs of MG investment and operation until grid arrival.

- **Discounting factor.** Cash flows in the future are discounted with the discounting factor d, depending on the time they occur:

  $$d(t) = (1 + wacc)^t \tag{A.1}$$

  A cash flow CF in year t would be transferred into a present value like so:

  $$PV = CF \cdot d(t) \tag{A.2}$$

- **Capital recovery factor** The CRF translates annuities into present costs and vice versa, accounting for the time value of money. It is calculated based on the Weighted Average Cost of Capital (WACC) and the year t. This describes either the year in which a cash flow takes place, in case of a future cash flow, or how long a constant payment will be made.

  $$CRF(t) = \frac{wacc \cdot (1 + wacc)^t}{(1 + wacc)^t - 1} \tag{A.3}$$

A PV PV is translated into an annuity A, a continuing flow of payments distributed over time t, with:

$$A = PV \cdot CRF(t) \tag{A.4}$$

With a project duration of 20 a, $CRF(20)$ describes the total project duration, while $CRF(t)$ depends on the year of grid arrival. $CRF(t)$ can be used to calculate the total present value PV of annual payments that only took place until grid arrival in year t:

$$PV(t) = \frac{A}{CRF(t)} \tag{A.5}$$

Regular cash flows after grid arrival until project end are be calculated with $CRF(20-t)$ and then discounted to a present value. This can e.g. display revenues through feed-in starting from interconnection until project end.

$$PV(t) = \frac{A}{CRF(20-t) \cdot d(t)} \tag{A.6}$$

Now, the cost calculations considering the MG operator's perspective are presented. All of the cases consider, that the off-grid MG runs until grid arrival. As such, Investment, operation and maintenance costs as well as fuel expenditures of the off-grid MG until interconnection are calculated:

$$PV_{offmg,op} = \frac{A_{offmg}}{CRF(t)} \tag{A.7}$$

Abandonment. If the MG operator terminates MG operation, all assets are left as stranded.

- **Abandonment costs.** As a simplification, the abandonment costs PV_A of the MG are equal to its residual value at time of interconnection with the grid, i.e. the sum of all annuities starting from grid arrival. This overestimates the abandonment costs, as in reality some components would not have to be replaced after MG termination (e.g. batteries) and wear costs of the components would not have to be paid. As fuel expenditures can be avoided after termination, they are subtracted.

$$PV_A = \frac{A_{offmg} - A_{fuel}}{CRF(20-t) \cdot d(t)} \tag{A.8}$$

- **NPV.** The NPV is the sum of off-grid MG operation and abandonment costs:

$$NPV_A = PV_{offmg,op} + PV_A \tag{A.9}$$

Reimbursement. The MG operator receives a reimbursement when the grid arrives and the MG is terminated.

- **Reimbursement.** The reimbursement for interconnecting MG PV_R, as defined in Nigerian regulation [72], covers the costs of abandonment as well as a year's worth of revenues. A profit margin of q of 2 % is assumed.

$$PV_{R,all} = PV_A + \frac{E_{dem} \cdot LCOE \cdot (1+r)}{d(t)} \tag{A.10}$$

- **NPV.** The NPV of reimbursement equals off-grid MG operation, abandonment costs and reimbursement. As reimbursement costs include abandonment costs, abandonment can be avoided altogether.

$$NPV_R = PV_{offmg,op} + PV_A - PV_{R,all} \tag{A.11}$$

Small power producer. When transforming into an SPP, the operator abandons all diesel generator and storage capacities but receives a reimbursement for the distribution grid. As SPP, it feeds-in its solar generation into the utility grid. For that, it has to install a grid-tied transformer station.

- **Annual solar generation.** The annual solar generation E_{solar} [kWh/a] is calculated from the optimized PV capacity CAP_{pv} and the annual solar generation time series provided for the project location.

$$E_{solar} = \int P_{solar} \cdot CAP_{pv} \tag{A.12}$$

  The peak solar generation of the whole PV system is calculated alike:

$$P_{solar,p,total} = P_{solar,p} \cdot CAP_{pv} \tag{A.13}$$

- **Feed-in revenues.** The SPP generates feed-in revenues $PV_{retail,spp}$ from the solar generation it feeds into the grid at feed-in tariff FIT. They only occur after grid arrival.

$$PV_{retail,spp} = \frac{E_{solar} \cdot FIT \cdot \eta_{CG}}{CRF(20-t) \cdot d(t)} \tag{A.14}$$

  As no further simulation is performed, it is assumed that all generated electricity is feed into the central grid. However, if the grid is unreliable, this simplification leads to an overestimation of feed-in revenues.

- **Future operation costs.** A part of the MG components is continued to be utilized after grid interconnection: PV panels and the inverter. To be able to feed-in into the grid, they also require a system upgrade in form of a transformer station of peak solar generation capacity $P_{solar,p}$ for feed-in.

$$PV_{spp,op} = \frac{A_{pv} + A_{inv} + \frac{A_{pcc}}{CAP_{pcc}} \cdot P_{solar,p,total}}{CRF(20-t) \cdot d(t)} \tag{A.15}$$

- **Abandonment costs.** The SPP abandonment costs $PV_{A,spp}$ differ from the generalized ones, as the PV system and inverters are further utilized.

$$PV_{A,spp} = PV_A - \frac{A_{pv} + A_{inv}}{CRF(20-t) \cdot d(t)} \tag{A.16}$$

- **Reimbursement of distribution grid.** If the distribution grid is implemented adhering to national norms, the utility arriving at the project location can utilize it and reimburse the MG operator for its implementation based on its residual value. For the SPP, as it is allowed to operate as a grid-connected distributor, it is assumed that the distribution grid adheres to national standards.

$$PV_{R,distr} = \frac{A_{dist}}{CRF(20-t) \cdot d(t)} \tag{A.17}$$

- **NPV.** The NPV of a small power producer includes the investments until grid arrival, its abandonment costs, future operation costs, reimbursement for the distribution grid as well as the revenues generated through solar feed-in.

$$NPV_{spp} = PV_{offmg,op} + PV_{A,spp} + PV_{spp,op} - PV_{feedin} - PV_{R,distr} \tag{A.18}$$

Small power distributor. an SPD transforms the MG into a distribution system, while it abandons all other assets.

- **Future operation costs.** Only the distribution grid is operated in the future. It is assumed that the transformer station belongs to the utility.

$$PV_{spd,op} = \frac{A_{dist}}{CRF(20-t) \cdot d(t)} \tag{A.19}$$

- **Abandonment costs.** The abandonment costs of the SPD do not include the further utilized distribution grid costs:

$$PV_{A,spd} = PV_A - \frac{A_{dist}}{CRF(20-t) \cdot d(t)} \tag{A.20}$$

- **Revenue through retail.** As an SPD, the MG operator buys electricity from the national grid at retail tariff and sells it to the consumers at main grid electricity price p_{el} with an included profit margin r of 2 %. This assumes that the national grid can provide all this electricity.

$$PV_{retail,spd} = \frac{E_{dem} \cdot \eta_{CG} \cdot p_{el} \cdot r}{CRF(20-t) \cdot d(t)} \tag{A.21}$$

- **NPV.** The NPV of SPP includes previous operation costs as well as abandonment and future costs. Future retail decreases the system's NPV.

$$NPV_{spd} = PV_{offmg,op} + PV_{A,spd} + PV_{spd,op} - PV_{retail,spd} \tag{A.22}$$

Grid-connected operation of off-grid MG. The NPV of off-grid MG interconnecting with the central grid and continuing their operation, both for consumption only and feed-in and cons, consumption, with the annuities of off-grid MG operation and the costs of the future post-interconnection option, i.e. Off-MG-C, Off-MG-CF, On-MG-C and On-MG-CF, and the interconnection costs, i.e. costs for extension and transformer station.

$$A_{intercon} = \frac{A_{ongrid} - A_{ext} - A_{pcc}}{CRF(20-t)\cdot d(t)} \tag{A.23}$$

$$NPV_{intercon,t} = \frac{A_{offmg}}{CRF(t)} + \frac{A_{intercon}}{CRF(20-t)\cdot d(t)} \tag{A.24}$$

This assumes that the distribution grid of the off-grid MG adheres to utility standards and can be interconnected.

Costs from MG operator perspective. The above detailed NPV's describe the costs of the post-interconnection options from a MG operator's perspective. Interconnection costs, i.e. grid extension and transformer station costs, are not included as it is assumed that the utility pays these investments. Revenues through retail (SPD) and feed-in (SPP) decrease these electricity costs, even though they occur in the context of a very different business model, as they also decrease the losses of the MG operator.
The resulting LCOE are calculated based on the electricity the MG provided until grid arrival and, if continued, for the whole project time. The future supply reliability η is taken into account.

$$LCOE_i = \frac{NPV_i}{\frac{E_{dem}}{CRF(t)} + \frac{\eta_{intercon}\cdot E_{dem}}{CRF(20-t)\cdot d(t)}} \tag{A.25}$$

As in case of abandonment, reimbursement, SPP and SPD, from an MG operator's perspective only the electricity until grid arrival is provided and after that $\eta_{intercon} = 0$, their NPV is essentially distributed over the first years of operation alone.
Based on this LCOE, the operator can compare the post-interconnection costs to those of other options and available subsidies, ultimately deciding for a future operation strategy.

Costs from electrification planning perspective. When creating an electrification plan, the total costs are minimized. This includes not only MG costs but also costs for reimbursements and grid extension. This way, the LCOE mirrors the global electrification costs.

- **NPV from electrification planning perspective.** The present value of grid extension PV_{ext}, including transformer station for consumption amounts to:

$$PV_{intercon} = \frac{(A_{ext} + A_{pcc})}{CRF(20-t)\cdot d(t)} \tag{A.26}$$

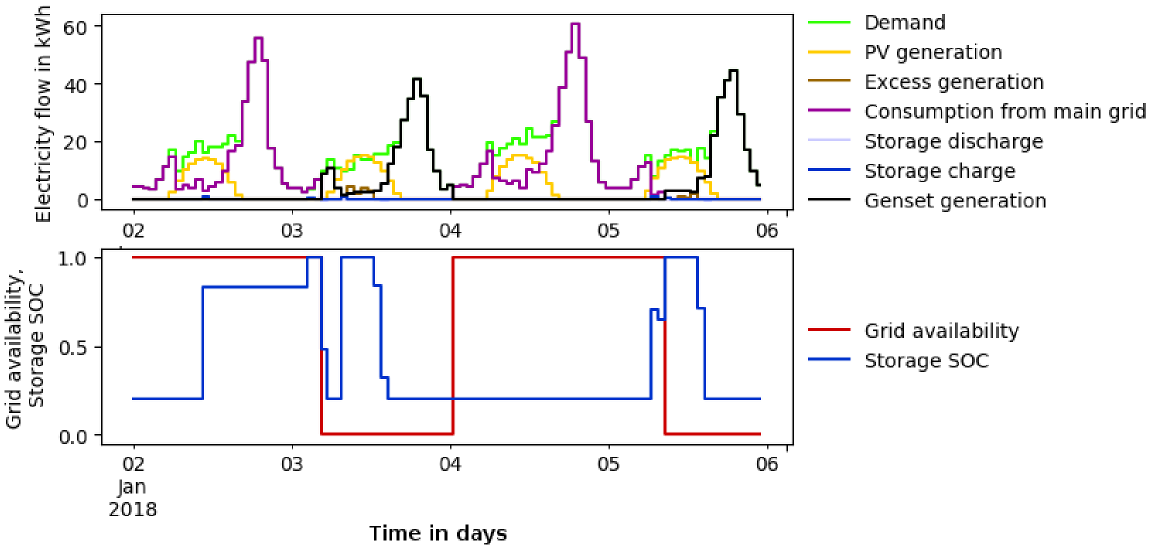
  The NPV from a electrification planner's perspective $NPV_{i,global}$ further includes the potential reimbursement payments PV_R and costs of electricity supply from the national grid. To calculate this value for unreliable national grids as well, the grid's reliability is taken into account η.

$$NPV_{i,global} = NPV_i + PV_{intercon} + \frac{\eta_{CG} \cdot E_{dem} \cdot p_{el}}{CRF(20-t)} + PV_R \tag{A.27}$$

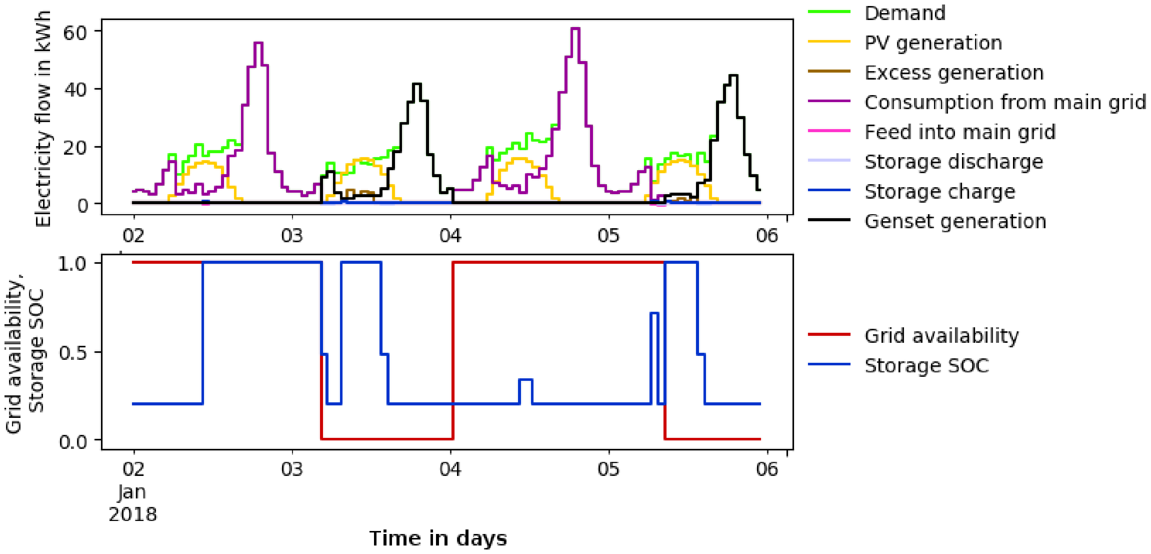
- **LCOE for electrification, electrification planning perspective.** From the NPV for electricity supply, the LCOE $LCOE_{i,global}$ over the different electrification stages can be calculated:

$$LCOE_{i,global} = \frac{NPV_{i,global}}{\frac{E_{dem}}{CRF(t)} + \frac{\eta_{intercon} \cdot E_{dem}}{CRF(20-t) \cdot d(t)}} \tag{A.28}$$

A.4. Energy flows on-grid optimized MG



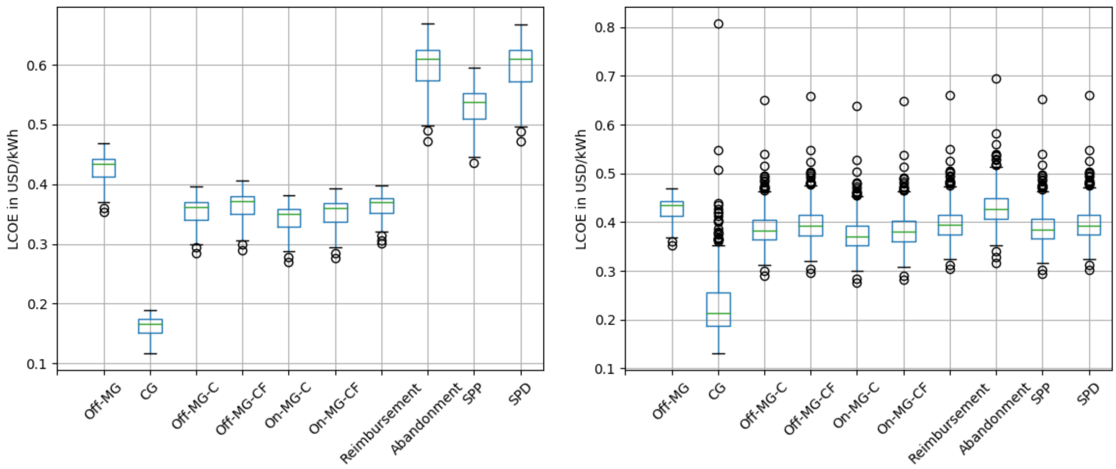
(a) *Only consumption from national grid*



(b) *Consumption from and feed-in into national grid*

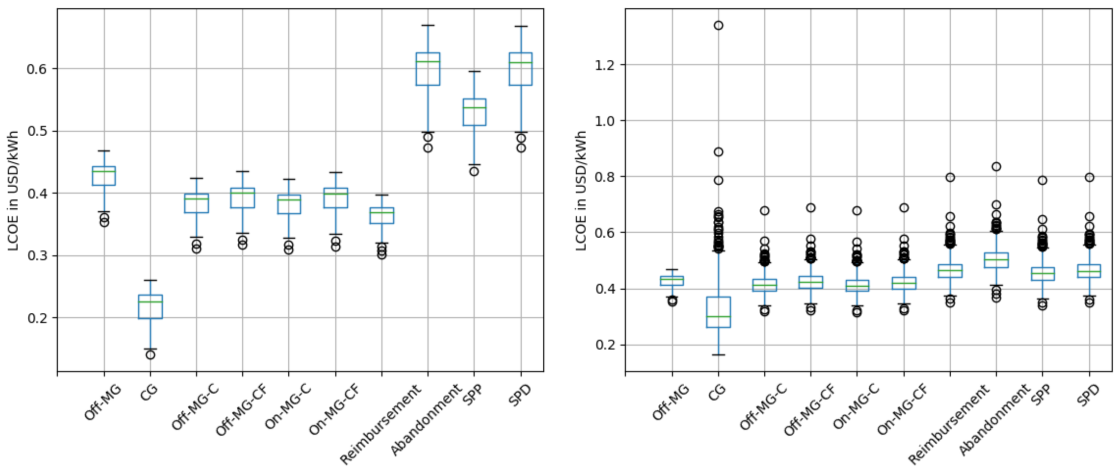
Figure A.1.: *Energy flows in on-grid MG connected to unreliable central grid (nesp 3670)*

A.5. Distribution of post-interconnection costs of all clusters



(a) *MG operator's perspective* **(b)** *Global perspective*

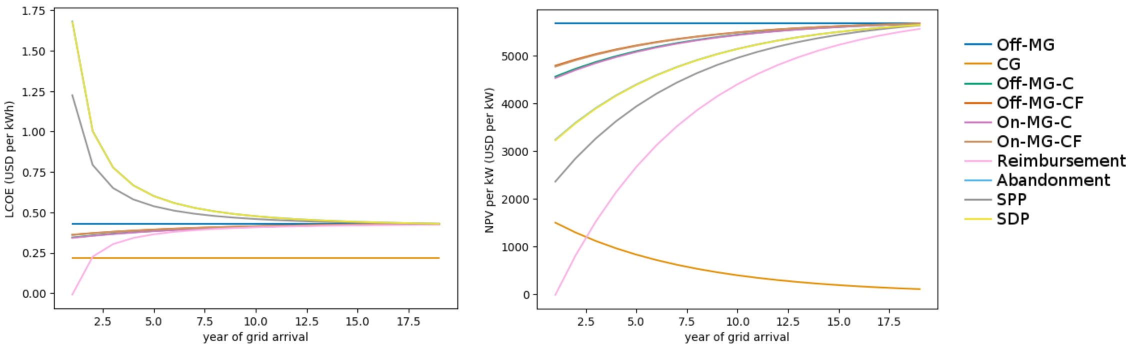
Figure A.2.: *Distribution of post-interconnection LCOE, grid arrival after 5 years, reliable*



(a) *MG operator's perspective* **(b)** *Global perspective*

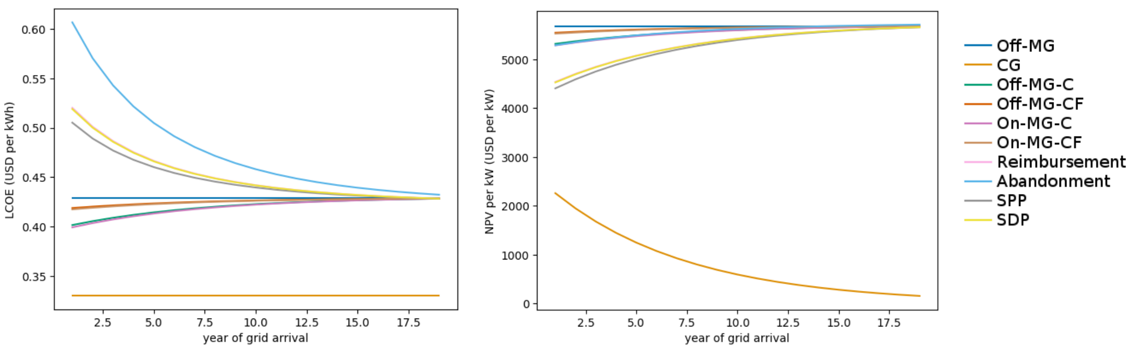
Figure A.3.: *Distribution of post-interconnection LCOE, grid arrival after 5 years, unreliable*

A.6. Influence of grid arrival time



(a) *LCOE* **(b)** *NPV/kW* **(c)** *Legend*

Figure A.4.: *Time of grid arrival and costs of post-interconnection options, MG operator, unreliable*



(a) *LCOE* **(b)** *NPV/kW* **(c)** *Legend*

Figure A.5.: *Time of grid arrival and costs of post-interconnection options, global, unreliable*