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DESIGN OF A ROBUST ENERGY MANAGEMENT SYSTEM FOR A GRID-CONNECTED MICROGRID PROVIDING SERVICES.

TESIS PARA OPTAR AL GRADO DE MAGÍSTER EN CIENCIAS DE LA INGENIERÍA, MENCIÓN ELÉCTRICA

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DISEÑO DE UN SISTEMA DE GESTION DE ENERGIA ROBUSTO PARA MICRO-REDES CONECTADAS APORTANDO SERVICIOS AUXILIARES

Se define una microrred como una agrupación de cargas y recursos energéticos distribuidos que funciona como un único sistema controlable, capaz de operar en paralelo o aislado de la red eléctrica. Las microrredes son proveedores de energía locales que pueden reducir los gastos de energía, reducir las emisiones, aumentar la confiabilidad y son alternativas de energización emergentes. El correcto uso de sus recursos energéticos disponible permite lograr una operación más eficiente en una microrred, por ejemplo; reducir sus costos, mejorar ingresos, alargar la vida útil de los equipos y limitar el impacto ambiental. Algunos de estos objetivos se contraponen y es por esto que es necesario compensarlos para obtener el mejor despacho energético. Por esta razón el uso de un sistema de gestión de energía para microrredes cobra gran importancia.

En este trabajo se desarrollaron modelos matemáticos y luego se implementaron en una herramienta computacional para el despacho energético óptimo de microrredes, con énfasis en tres aspectos. Primero, los servicios complementarios que una microrred puede ofrecer: arbitraje de energía, reducción de emisiones, reducción de potencia punta, reserva de potencia en giro y ofertas de reducción de consumo. Segundo, un modelo de almacenamiento de baterías enfocado en seis fenómenos: envejecimiento cíclico y calendario, la ley de Peukert, la pérdida de capacidad, autodescargas y la limitación de carga/descarga. Tercero, se incluye un módulo maestro-esclavo para lidiar con la estocasticidad ante problemas intempestivos en la red, manteniendo así la confiabilidad de la microrred cuando se aísla, aun si esta ofrece servicios.

Estos tres aspectos son integrados en un modelo de programación lineal entera mixta para el despacho óptimo de una microrred, minimizando los costos de operación y reinversión. En el presente trabajo, se simulan la operación de tres microrredes reales bajo diferentes escenarios cada uno. El primer caso es la microrred aislada de Huatacondo, el segundo es la microrred conectada de CIGRE y el tercero es la microrred conectada de la cárcel de Santa Rita.

Los resultados obtenidos muestran reducción en los costos de hasta 4.3% en la microrred de Huatacondo, hasta 2.9% para CIGRE y hasta 7% para Santa Rita al considerar servicios y utilizando un modelo detallado de almacenamiento. En el caso de la microrred aislada de Huatacondo, la reducción se basó principalmente en la extensión de la vida útil del banco de baterías. Para las dos microrredes conectadas los servicios más atractivos fueron ofrecer sus capacidades flexibles no utilizadas a la red. Esto considera servicios como reducción de consumo, reducción de demanda punta o reserva en giro. Servicios enfocados en transferencia de altos volúmenes de energía, como el arbitraje de energía, no fueron atractivos dado el costo asociado al uso de equipos de almacenamiento.

Abstract

A microgrid is defined as a group of distributed energy resources and loads that function as a single controllable system, capable of operating in parallel or isolated from the electrical grid. A microgrid is a local energy provider that can reduce energy costs, reduce emissions, increase reliability and are emerging energization alternatives.

The correct use of the energy resources available in a microgrid allows it to achieve more efficient operation, for example; reduce costs, improve revenues, extend the useful life of the equipment and limit the environmental impact. Some of these objectives are opposed and that is why it is necessary to compensate them to obtain the best energy dispatch. For this reason, the use of a specific energy management system for microgrid is required.

In this work, mathematical models were developed and then implemented in a computational tool for the optimal energy dispatch of a microgrid, with emphasis on three aspects. First, the complementary services that a microgrid can offer: energy arbitrage, reduction of emissions, spinning reserve, peak shaving, and capacity bidding. Second, a battery storage model focused on six phenomena: cyclical and calendar aging, Peukert's law, loss of capacity, self-discharge and charge/discharge limitation. Third, a master-slave module is included to deal with stochasticity in the event of ill-timed problems in the grid, thus maintaining the reliability of the microgrid when it offers services.

These three aspects are integrated into a mixed integer linear programming model for the optimal dispatch of a microgrid, minimizing the operation and reinvestment cost. In the present work, the operation of three real microgrids under different scenarios were simulated. The first case is the isolated microgrid of Huatacondo, the second is the connected microgrid of CIGRE and the third is the connected microgrid of the Santa Rita Jail. The simulations were solved with the software FICO Xpress IVE 1.24.

The results obtained show a reduction in costs of up to 4.3% in the Huatacondo’s microgrid, up to 2.9% for CIGRE’s and up to 7% for Santa Rita’s microgrid when considering available services and using a detailed storage model. In the case of Huatacondo's isolated microgrid, the reduction was mainly based on the extension of the useful life of the battery bank. For the two connected microgrids, the most attractive services were to offer their available flexible capacities

to the grid. This includes services such as spinning reserve, peak shaving and capacity bidding. Services focused on transferring high volumes of energy, such as energy arbitrage, were not attractive given the cost associated with the use of storage equipment.

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NOMENCLATURE

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T: Maximum number of optimization periods

n_v: Maximum number of piecewise linear segments for battery degradation based on SoC

n_w: Maximum number of piecewise linear segments for Peukert Law

n_q: Maximum number of piecewise linear segments for BESS charge power constrains.

n_b: Maximum number of batteries

n_L: Maximum number of loads to supply

n_d: Maximum number of controllable loads

n_E: Maximum number of periods where an unplanned event can happen

n_s: Maximum number of slaves

Binary variables

$BF_{v,i,t}$: Indicates if v piece for generator i on period t is on

$B_{i,t}$: Indicates if generator i on period t is on

$Bsoc_{b,v,t}$: Indicates if on period t the piece v of BESS b is active for Aheff based on SoC

$Bpeuk_{b,w,t}$: Indicates if on period t the Peukert Law piece w of BESS b is active on period t

$B_{b,q,t}$: Indicates if on period t the piece q for charge limitations of BESS b based on SoC

Continue variables

$FC_{i,t}$: Fuel cost of the generating unit i in period t

$MC_{i,t}$: Maintenance cost of the generation unit i on period t

$SU_{i,t}$: Startup cost for unit i on period t

$\Delta SoH_{i,t}$: Reduction of health in the BESS i on period t

UE_t: Penalty imposed by having unserved energy on period t

GB_t: Energy bought from the main grid on period t

GS_t: Energy sold to the main grid on period t

AS_t: Auxiliary services the MG provide to the main grid on period t

$FC_{v,i,t}$: Fuel cost of piecewise linear segment v of the generating unit i in period t

$PF_{v,i,t}$: Power of piecewise linear segment v of the generating unit i in period t

$\Delta SoH_{i,t}$: Reduction of health in the BESS i on period t

$LoLc_{b,t}$: Loss of life caused by cycling BESS i on period t

$LoLt_b$Loss of life is caused by calendar degradation of BESS i

$UE_{i,t}$. Energy not served to load i on period t

$PD_{i,t}$: Power of dispatchable generation unit i on period t

$PS_{i,t}$ Power of the BESS i on period t (Can be positive or negative)

$Pimp_t$: Imported power from the grid on period t

$Pexp_t$: Exported power to the grid on period t

$UE_{i,t}$: Unserved energy for load i on period t

$E_{b,t}$: Energy on the BESS b on period t

$Pb^+_{t,i}$: Power BESS i provides to the MG on period t

$Pb^-_{t,i}$. Power BESS i absorbs from the MG on period t

$Eb0_i$: Energy of BESS i at the start of the simulation

$\overline{CL_{\iota,t}}$: Modified controllable loads

$\lambda_{b,t}$: Effective charged power of BESS b on period t

$Pb^+_{b,t,v}$: Discharged power for piecewise linear segment v of BESS b on period t

$Cbess_{b,t}$: Cost of using BESS b on period t

$\delta_{b,t}$: Weighted power discharged from BESS b on period t

$P^-_{b,t}$: Effective power discharged from BESS b on period t

$P^-_{b,w,t}$: Effective power discharged or piecewise linear segment w from BESS b on period t

$Pmin_{b,w}$: Minimum power for piecewise linear segment w BESS b

$Pmax_{b,w}$: Maximum power for piecewise linear segment w BESS b

$Psd_{b,t}$: Self-discharged power for BESS b on period t

E^0_b: Initial energy on BESS b

$Pexp_t$: Power exported to the Grid on period t

$Pimp_t$: Power imported from the Grid on period t

Rdw: Down spinning reserve

Rup: Up spinning reserve

$Ppeak$: Maximum imported power from the grid

Z_k: Bender's cut for slave k,

$dE_{b,k}$: Marginal cost of an increase/decrease in unserved energy for slave k

$Eb0_b$: Stored energy on BESS b obtained from the previous master problem,

Eb_slv_k: Initial state of slave k for new iteration

$FOslv_k$: Cost of objective function on slave k

Z_R: Reliability Bender's cut added to the objective function of the master problem

$Pimp\_slv_{k,t}$: Imported power from the grid for slave k on period t

$dCB_{b,k}$: Marginal cost of an increase/decrease in unserved energy for slave k

Pcb_slv_0: CB obtained from the previous master problem,

Pcb_slv_k: Capacity bidding of slave k for new iteration

ΔFO_slv_k: Increased in OF cost of providing CB in slave k

Z_{CB}: CB Bender's cut added to the objective function of the master problem

Constants

$PND_{i,t}$: Power of non dispatchable generation unit i on period t

$da_{v,i,t}$: Incremental value of piecewise linear segment v for generation unit i on period t

$db_{v,i,t}$: Constant value of piecewise linear segment v for generation unit i on period t

M_i: Base maintenance cost for generation unit i, independent of the unit use

mc_i: Incremental maintenance cost for generation unit i

$\text{CPstart}_{i,t}$: Cost associated with starting up the generation unit i on period t

$Cbess_b$: Reinvestment cost of the BESS b

UEP_i: Penalty value for each kWh not provided to load i

$NL_{i,t}$: Load of non-controllabe load i on period t

$PDmin_i$: Minimum power for dispatchable unit i

$PDmax_i$: Maximum power for dispatchable unit i

ηd_b: Discharge efficiency of BESS b

ηc_b: Charge efficiency of the BESS b

$Ebmin_b$: Minimum energy BESS b can have

$Ebmax_b$: Maximum energy BESS b can have

$CL_{l,t}$: Original expected consumption of controllable load l on period t

$Pexp$: Maximum power the Grid can accept from the MG

$Pimp$: Maximum power the grid can provide to the MG

$DRmax_{l,t}$: Maximum range to which controllable load l can be increased on period t

$DRmin_{l,t}$: Minimum range to which controllable load l can be reduced on period t

Ah_eff_b: Effective Ah-throughput that BESS b can achieve before reaching its EoL

U_b: Average voltage for BESS b

$\lambda_{b,v}$: Weight for piecewise linear segment v for BESS b

$SOCmin_{b,v}$: Minimum SoC for piecewise linear segment v on BESS b

$SOCmax_{b,v}$: Maximum SoC for piecewise linear segment v on BESS b

Δt_t: Length of period t (in hours)

CL: Total Calendar Life in hours of BESS b

SoH_b: Initial SoH of BESS b

Eb_min_b: Minimum energy that can be stored on the BESS b

Eb_max_b: Maximum energy that can be stored on the BESS b

ηsd_b: Self-discharge coefficient for BESS b

$\propto_{q,b}$: Linear value of piecewise linear segment q for BESS b

$\beta q_{,b}$: Constant value of piecewise linear segment q for BESS b

$Emax_{b,q}$: Maximum bound for piecewise linear segment q for BESS b

$Emin_{b,q}$: Minimum bound for piecewise linear segment q for BESS b

$Cexp_t$: Value of exporting energy to the grid on period t

$Cimp_t$: Value of importing energy to the grid on period t

C_{CO2}: Payment for each ton of CO2

ηer_t: Tons of CO2 reduced by each displaced kWh on period t

Cmg_t: Marginal cost per kWh at the PCC on period t

α_{ER}: CO2 emissions of a coal based power plant,

β_{ER}: CO2 emissions of a gas based power plant

γ_{ER}: CO2 emissions of a diesel based power plant

C_{dw}: Payment per kW of down spinning reserve

C_{up}: Payment per kW of up spinning reserve

$Cpeak$: Payment per kW of peak power

Cue_l: Penalty cost of load l

a_k: Probability of scenario k occurring

Pcb: Power reduction offered for CB service.

$Pimp\_ms_t$: Imported power on the original master problem on period t

Glossary of Terms

MG	Microgrid
BESS	Battery energy storage system
EMS	Energy management system
DR	Demand response
SRJ	Santa Rita Jail
DER	Distributed energy resources
T&D	Transmission and distribution
DG	Distributed generation
BESS	Battery energy storage systems
EPS	Electric power systems
LA	Lead-acid
NiCd	Nickel–cadmium
Li-ion	Lithium ion
NaS	Sodium sulfur
NiMH	Nickel-metal-hydride
SoC	State of charge
SoH	State of health
DoD	Depth of discharge
EoL	End of life
PCC	Point of common coupling
MGCC	Microgrid central controller
AS	Ancillary services
MILP	Mixed Integer Linear Programming
DSM	Demand-side management
CB	Capacity bidding
TSO	Transmission system operator
BS	Black Start
NSE	Non Supplied Energy
ISO	Independent system operator
IESO	Independent Electricity System Operator
PG&E	Pacific Gas and Electricity company

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1 INTRODUCTION

1.1 MOTIVATION

Currently, a lot of research is being undertaken into microgrids (MGs), and some of it is focusing on connected microgrids. Whilst much work is being carried out to improve efficiencies on a single service or improving coordination, this thesis will explore how a MG can maximize its revenues while having access to multiple services. Previous works have focused on optimizing for a single revenue stream, such as considering only arbitrage in [1], or ignoring some critical phenomena, such as battery degradation when providing arbitrage in Raymond et al work [2] or Feng Guo battery energy storage system (BESS) extending techniques [3]. Multiple studies, such as [4], [5], and [6], identify that looking at a single service can lead to undervaluing the potential of a BESS (on a MG) and its economic viability. Studies similar to the ones presented tend to ignore the full potential and weaknesses of MG equipment, which leads to less efficient use of the MG assets, as Karl Hartwig et al studied on [7].

MG's equipment already possesses a high level of flexibility, required for operating in islanded conditions, some of which can be taken advantage of while the MG is connected. This flexibility can be harnessed by the main grid, providing it with much-needed flexibility without additional investment. To ensure the MG retains its ability to island itself while providing these services, a robust solution that doesn't compromise the MG's islanding capacity needs to be included.

The purpose of this thesis is to optimize the services a MG can offer among all its options, using its otherwise idle equipment, while considering the detrimental effect such operation has on the equipment and the MG's reliability.

1.2 HYPOTHESIS

This thesis hypothesizes that a robust EMS which includes a detailed BESS model and offers services to the grid can increase the revenue for the MG without compromising its reliability.

1.3 RESEARCH OBJECTIVES

This main objectives of the research presented in this thesis involves studying the impact of offering services to the grid using a robust energy management system (EMS) with a detailed BESS model for a connected Microgrid.

The research questions we want to answer in this thesis are:

- Can a MG provide local services to support the grid?
- How does the MG's operation cost change when services are offered?
- When offering services, which characteristics are crucial to model on a BESS?
- Is it possible to provide the services without compromising the MG's reliability?

1.3.1 SPECIFIC OBJECTIVES

To answer these questions, the specific objectives of this work are:

- Examine all possible services a MG can provide to the grid and generate models for selected services.
- Study the phenomena that affect BESS operation and life for technologies typically used in MG and generate models for them.
- Develop a robust mixed Integer linear mathematical dispatch model for connected or isolated MG's dispatch, including the previously mentioned models, able to provide adequate dispatch conditions for unexpected islanding.
- Validate the proposed model solving the dispatch problem of three different MGs under different scenarios.
- Evaluate and analyze the benefits and drawbacks a MG can generate by offering services to the Grid.

1.4 SCOPE

This thesis develops and implements a mathematical optimization model for the optimal dispatch of a single islanded or connected microgrid. This tool can also be used for non-microgrid medium and small-sized systems that require management of their energy and include battery-based storage systems.

The focus of this model is on the battery modeling, MG's services and a robust dispatch tool using a uninodal model, implemented using the software FICO. Transient studies and stability analyses are out of the scope of this work.

Most of the work presented in chapter 2 (state of the art) include only one service at a time and/or do not include a detailed BESS model. This thesis presents a holistic solution and the results obtained consider the inclusion of multiple services simultaneously, combined with an advanced BESS model.

1.5 CONTRIBUTIONS

The main contributions of this thesis are summarized as follows:

- A comprehensive mathematical optimization model for energy management of isolated or connected microgrids is developed to examine the potential of the MG to offer services to the Grid and choosing which one(s) to offer between multiple, sometimes conflicting, services.
- A detailed model of Battery Energy Storage Systems, for multiple technologies, including Peukert Law, Calendar life, cycling degradation, self-discharges, capacity fading and charge limitations, allowing a far more reliable model of battery operation.
- A novel robust optimization strategy for unplanned contingencies in MGs, such as outages or reduction in imported energy. The proposed problem formulation thus minimizes the expected operational cost of the microgrid during normal operation and the additional cost of unplanned operation with a master-slave iterative process using Bender's decomposition.

1.6 STRUCTURE OF THE DOCUMENT

According to the presented objectives, this thesis is structured in the following way:

Chapter 1 presents the motivation behind this research and lays out the objectives this thesis will tackle.

Chapter 2 presents a background review of the subjects, tools, and models used in research similar to this thesis. An overview of the essential components of the microgrid, such as distributed generators and battery storage systems, is discussed. Research related to energy management problem, robust dispatch and scheduling for MGs is presented in this chapter. Finally, the different services literature has identified a microgrid can offer to the electrical grid are presented.

Chapter 3 proposes a robust mathematical optimization model for the short-term operation of a microgrid capable of offering services. This model solves an optimal energy management problem considering energy storage, dispatchable generators, and renewable generators. Islanded and connected operations are both considered. Additionally, demand response (DR) and offering services to the electrical grid while ensuring reliability can be included.

Chapter 4 presents the simulation results of three different microgrids, Huatacondo, CIGRE, and Santa Rita Jail (SRJ). A variety of cases studies are carried out using the proposed model. The case study scenarios are selected to obtain insights into the effect of the different phenomena modeled in Chapter 3, such as demand response, battery degradation, Peukert's Law, reliability and offering capacity bidding.

Chapter 5 presents the general conclusions of the developed EMS and insights obtained from previous chapters. Finally, ideas for future work are proposed.

2 STATE OF ART

In this chapter, we explore the concept of distributed energy resources (DER), what a MG is, how to organize it, the power and energy problem it faces and the services a MG can provide to the main grid.

2.1 DISTRIBUTED ENERGY RESOURCE

Traditionally, electricity is generated in large-scale centralized power plants and is transmitted over long distances by high voltage transmission lines to reach consumption areas. As identified in [**8**], the construction of new large centralized power generating plants and their associated transmission lines is unlikely to keep pace with the seemingly inexorably growing electricity appetite of the modern world. Environmental concerns, and a general “not in my backyard” or “build absolutely nothing anywhere near anybody” attitude toward large power facilities will make the current centralized generating paradigm incapable of adequate expansion.

A DER is a small-scale energy source which can be located at utility facilities or at customer’s premises, capable of storing or generating energy, to provide a local supply of electricity. Thus DER can potentially result in a significant change in the traditional methods of energy generation, providing power to remote locations where transmission and distribution (T&D) facilities are not available or are too costly to build. DER also offer a low construction and deployment time compared to large generators and T&D facilities.

With the increased interest in renewable resources, such as wind and solar energy, in recent years two types of DERs have gained considerable attention, renewable distributed generation (DG) and battery energy storage systems (BESS).

One of the main drivers for this trend includes the clean and sustainable nature of such resources, which typically don’t generate pollution during generation, especially when compared to the polluting and finite fossil fuels that have traditionally been used to generate power.

DG units within an electric power system also offer technical advantages, due to being physically closer to the final consumer, in terms of power quality and reliability as well as energy management and efficiency (fewer distribution losses). It offers economic advantages in terms of reducing capital investment for construction of power systems since the distribution of generation units eliminates the need for long transmission systems, as it is well known that it is very difficult to construct new transmission lines.

As presented in [9], one way to handle load growth and enhance stability with transmission is to use the existing electrical system in a more effective way. DER on the distribution system can be used to meet load needs by strategically placing storage and generation units through the distribution system. With correct sizing and placement of DER units, the system can have fewer losses, fewer transmission congestions, more stable markets and a higher level of security without new generation or transmission.

Traditionally, utility electric power systems (EPS) were not designed to accommodate active generation and storage at distribution level. As a result, there have been major issues and obstacles to an orderly transition to using and integrating distributed power resources with the grid. This is why in 2003, the Institute of Electrical and Electronics Engineers (IEEE) published “IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems” [10], to fully integrate the benefits of DER and to avoid negative impacts on system reliability and safety.

There are several advantages DER can provide, for example [10] shows that DER can change the area EPS voltage. If power from a DER device is injected into the power system, it will offset load current and thus reduce the voltage drop on the area EPS. Just the existence of a DR can completely offset the local EPS load, and this may result in a voltage rise due to the elimination of the “voltage drop”.

Local generation not only increases overall system efficiency, as indicated in [11], but also reduces investments in traditional generation, bulk transmission, and distribution facilities. The utility can also serve incremental load growth in areas where there is a shortage of substation and/or distribution feeder capacity.

DER units offer a variety of possibilities for energy conversion and electric power generation. Various energy sources and converters are used to provide electricity through conventional diesel and natural gas reciprocating engines, microturbines, fuel cells, wind turbines, PV arrays, and energy storage among others.

2.2 BATTERY ENERGY STORAGE SYSTEMS

This section discusses BESS, which can facilitate high penetration and integration of variable renewable energy sources, such as the ones mentioned in the previous section.

A storage system enhances flexibility in power generation, delivery, and consumption. It provides utility grids with several benefits and large cost savings. Large-scale storage systems increase the efficiency of utility grids which means reduced operating cost and emissions and increased power reliability. Considering the increasing penetration of renewable DG, the application of storage systems has become significantly more common. The reason is that renewable DG is intermittent; for example, wind farms and photovoltaic plants only generate power when the wind is blowing and the sun is shining respectively. The employment of BESS allows the storage of energy when the generation is higher than the demand, which can be supplied when required.

Storing energy from various resources to shift loads based on electricity prices and serve non-shiftable loads during peak hours is one of the several applications of storage systems. The employment of storage systems can improve power quality via frequency regulation, benefit electric producers by allowing them to generate power when it is most efficient and least expensive, provide critical loads with a continuous source of power, and help society during emergencies such as electricity interruptions caused by storms, equipment failures, or malicious attacks [**12**].

Storage systems can be divided based on how they store energy. They are divided into mechanical, electrochemical, chemical, electrical and thermal storage systems, as shown in Figure 1. For this thesis, we will focus on the electrochemical, also known as BESS.

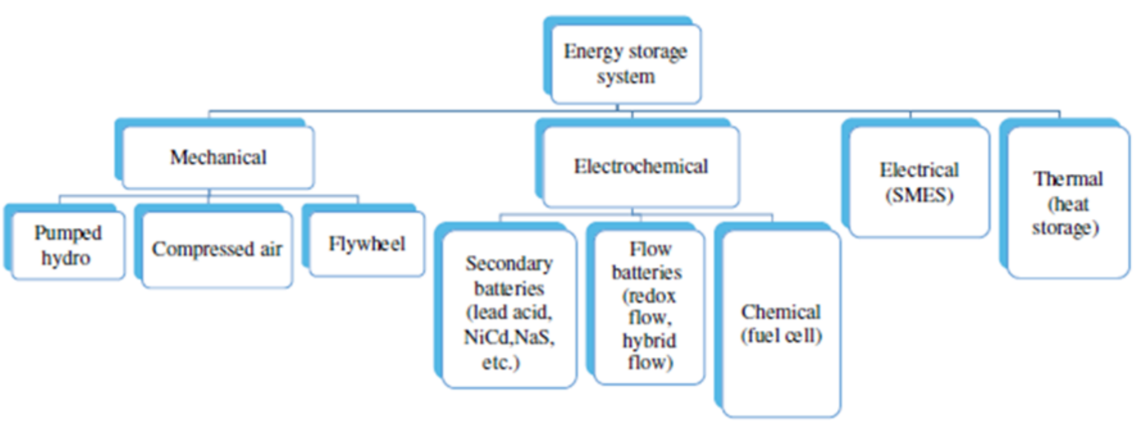

Figure 1: Classification of energy storage systems. Source: Fraunhofer ISE

2.2.1 BATTERY ENERGY STORAGE SYSTEM

Batteries are electrochemical storage devices made up of one or more building blocks, or cells. A battery cell, presented in Figure 2, contains a positive electrode, a negative electrode of a different material and an electrolyte material (the medium for electron transfer between the two electrodes).

The method by which each cell is able to convert input electrical energy into stored chemical energy, and stored chemical energy into electrical energy is through an oxidation-reduction or redox reaction. Through oxidation, electrons are lost, and through reduction electrons are gained (so when both oxidation and reduction occur, electrons leave one substance and make their way to another). The basic idea of charge and discharge is that current flows in the wire connected to a load or a power source, and inside the cell the voltage that is applied causes charged particles to drift from one electrode to the other during charge and discharge, and when they get to the electrode they might be able to give up an electron or take an electron through a chemical reaction, depending on whether the unit is charging or discharging. Chemically, the result of charge and discharge is to change the composition of the cell from one set of chemical species to another, then back again, as presented in Figure 2. Ideally, the reversibility of this reaction could go on indefinitely.

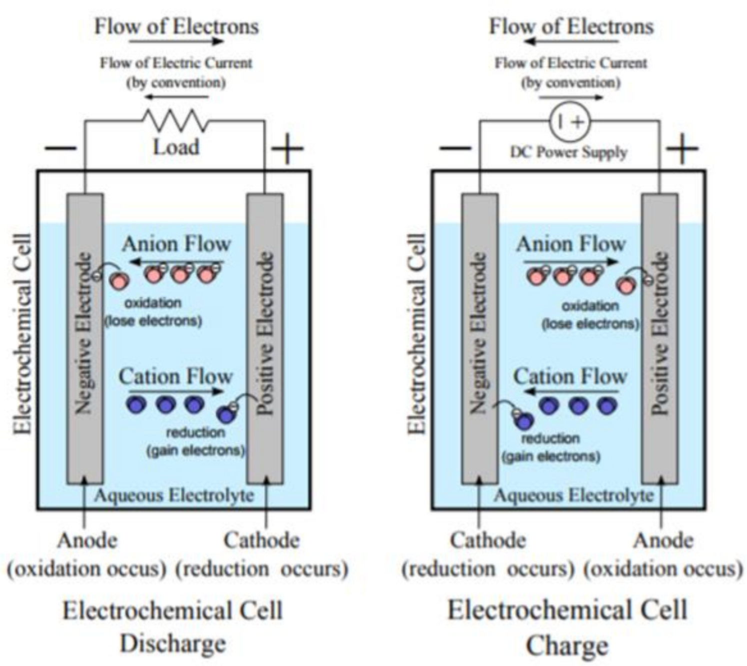

Figure 2: Charge and discharge of an electrochemical cell. [**13**]

Batteries can are categorized as primary (non-rechargeable) and secondary (rechargeable) cells. Secondary batteries will be the ones considered on this thesis.

The charge/discharge rates, power capacity and other properties for each battery are determined by the battery design and its chemical composition. Figure 3 presents the different power and storage capacity based on different energy storage technologies.

For DER applications, the storage needs to focus mainly on capacity over power, which makes Lead-acid (LA), Nickel–Cadmium (NiCd), Lithium Ion (Li-ion), Sodium Sulfur (NaS) and Redox flow batteries the most suitable BESS for a MG.

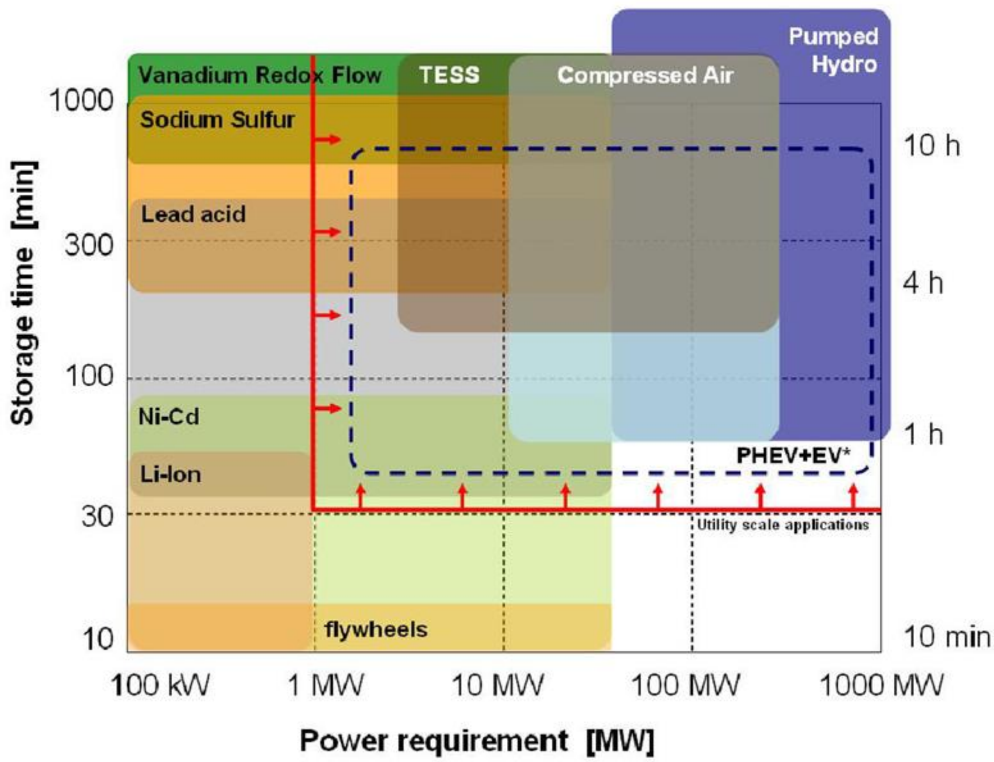

Figure 3: ESS power and capacity for different technologies. [**14**]

2.2.1.1 Lead-Acid batteries

Invented by the French physician Gaston Planté in 1859, LA was the first rechargeable battery for commercial use. This device operates based on the principles of redox reactions in electrochemical cells previously described, with the negative electrode composed of a lead alloy grid and pure lead active material. The positive electrode is made of a lead alloy grid with lead-oxide active material. The electrolyte is a solution of sulfuric acid in water. There are a number of types of LA batteries available, each with different characteristics.

Despite its advanced age, the LA battery continues to be in wide use today. It is the most commercially mature battery technology and the cheapest energy storage device on a cost-per-watt.

LA has a moderate life span, but it is not subject to memory effects, and the charge retention is one of the best among rechargeable batteries. Lead acid self-discharges 40% of its energy in one year and has a round-trip efficiency of 70-80%. The lead-acid battery can still work well at cold temperatures.

The primary reasons for its relatively short cycle life are grid corrosion on the positive electrode, depletion of the active material and expansion of the positive plates. This aging phenomenon is accelerated at elevated operating temperatures and when drawing high discharge currents. Thus, lifetime is heavily dependent on discharge patterns.

The LA battery maintains a strong foothold as being rugged and reliable at a cost that is lower than most other chemistries. The global market of LA is still growing but other systems are making inroads.

2.2.1.2 Nickel-Metal batteries

Invented by Waldemar Jungner in 1899, the NiCd battery offered several advantages over LA. The standard NiCd remains one of the most rugged and forgiving batteries and the airline industry stays true to this system, but it needs proper care to attain longevity and Cadmium is a toxic metal that cannot be disposed of in landfills.

In the 1990s the new nickel-metal-hydride (NiMH) battery was developed, to solve the toxicity problem of the otherwise robust NiCd. NiMH batteries have a memory effect that causes a loss of capacity if not given a periodic full discharge cycle, but most of the characteristics of NiCd were maintained by the NiMH, offering a non-toxic replacement.

Nickel batteries have a high specific energy and require little maintenance, but have high costs and a somewhat low cycle life. Nickel-metal batteries self-discharges 80% of its energy in one year and has a roundtrip efficiency of 65-70%. In general, these devices can endure more extreme temperatures better than other batteries and can fully discharge without sacrificing loss of capacity, lifetime, or efficiency.

2.2.1.3 Lithium-ion batteries

Pioneering work of the lithium-metal battery began in 1912 under G.N. Lewis, but it was not until the early 1970s that the first non-rechargeable lithium batteries became commercially available. The inherent instability of lithium metal, especially during charging, shifted research to a non-metallic solution using lithium ions. In 1991, Sony commercialized the first Li-ion battery.

The Li-ion battery resembles a capacitor in the way it operates. There are three layers in a lithium-ion battery. The first layer is the anode and is made from a lithium compound. The second layer is the cathode and is made from graphite. The third layer is called the insulator, and it is located between the first and the second layer.

The term lithium-ion refers to a family of batteries that shares similarities, but the chemistries can vary greatly. Lithium-cobalt, Lithium -manganese, and Lithium-aluminum are similar in that they deliver high capacity and are used in portable applications. Lithium-phosphate and Lithium-titanate have lower voltages and less capacity, but are very durable.

Li-ion batteries have become popular in recent years due to their extremely high efficiency, as well as their high energy density, number of cycles, power density, and cell voltage, as compared to other battery systems. Li-ion batteries tend to have a very low self-discharge rate, in the range of 30-50% of its energy in one year and have a round-trip efficiency of 90-98%. In addition, the materials to make Li-ion batteries are abundant.

The disadvantage is that lithium is expensive. Currently, cost and safety issues are the two main factors that impede the promotion of Li-ion for widespread use in power systems.

2.2.1.4 Sodium batteries

Conceived by the Germans during World War II, the electrolyte of the molten salt battery is inactive when cold. Once activated with a heat source, the NaS battery can provide a high power burst for a fraction of a second or deliver energy over several hours.

The technological advantage of the sodium battery is its high power density, long battery lifetime (usually over 10 years) and high efficiency, in the 75-90% range. Compared with the other leading battery technologies, NaS battery shows much more attractive energy density (four times that of a lead-acid battery) and much lower cost. NaS battery also has a long cycle capability and are made of abundant low-cost materials that are suitable for high volume mass production.

The sodium-nickel-chloride battery, also known as ZEBRA, is a type of “molten salt” device. It must be heated to 270–350°C, a lower temperature than the original NaS battery. Compared to the NaS battery, it is less sensitive to overcharging and deep discharging, and potentially a safer device. However, it also has a lower energy and power density than NaS devices

If not in operation, heating may consume up to 14% of the battery’s energy per day, the equivalent of 5,100% of its maximum capacity annually. While the system is in operation it does not require additional heating. The minimum capacity for this technology is higher than for other BESS, ~20 kWh. A cool down takes 3 to 4 days; depending on the state of charge (SoC), reheating takes about 2 days.

2.2.1.5 Flow batteries

A flow battery is an electrical storage device that is a cross between a conventional battery and a fuel cell. The liquid electrolyte of metallic salts is pumped through a core that consists of a positive and negative electrode, separated by a membrane. The ion exchange that occurs between the cathode and the anode generates electricity. Figure 4 illustrates the flow battery concept.

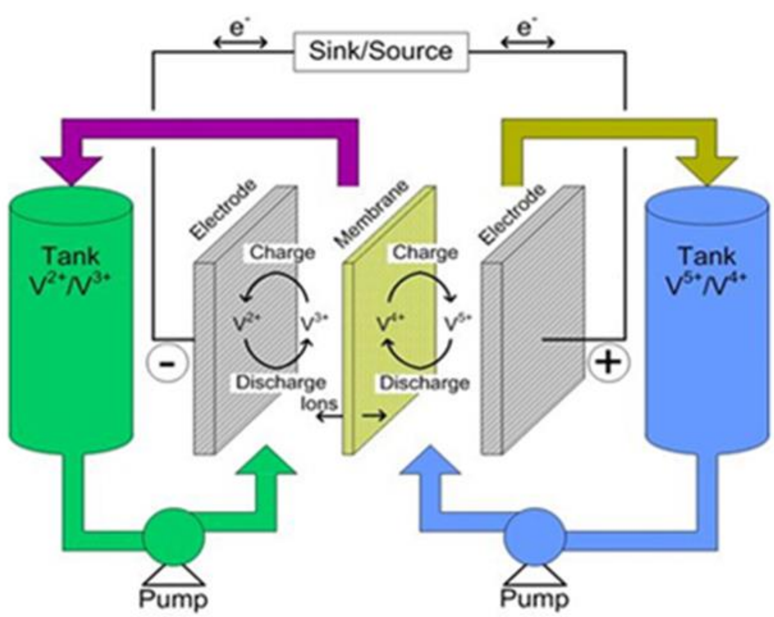

Figure 4: Flow Battery. [**14**]

Most commercial flow batteries use electrodes made of graphite bipolar plates and acid sulfur with vanadium salt as an electrolyte. Vanadium is one of few available active materials that keeps corrosion under control.

Due to its usage of pumps, flow batteries perform best at a size over 20kWh. They are said to deliver more than 10,000 full cycles and are good for about 20 years. Flow batteries have good round-trip efficiency, in the 85-90% range. Similar to NaS batteries, flow batteries self-discharges 10% of its energy daily when not in use, equivalent to 3,650% one year, but in operation this value can be almost 0%. Similar to the fuel cell, the power density and ramp-up speed is moderate. This makes the battery best suited for bulk energy storage.

2.2.2 BESS PROPERTIES

BESS exhibit many differences, not only between different technologies but also within the same technology, being characterized by complex efficiency and lifetime functions. The lifetime and efficiency of a BESS directly impacts (re-) investment and operational costs.

The efficiency of a battery is more dynamic than conventional power plants. The main factors are the SoC, state of health (SoH), charging and discharging power flows, and operating temperatures, as identified by the authors of [**15**]. The authors of [**16**] observed that battery operation is often simplified and part of their behavior is neglected, such as: discharge current (based on Peukert's law), depth of discharge (DoD) (which affect the battery cycles), calendar life (which limits the lifetime of the battery even when not in use), self-discharge (based on technology and time without operating) and temperature. Also, battery aging is rarely captured and a model blind to this phenomenon may over or under-estimate the real operation of the BESS. These properties will be further discussed in this section.

2.2.2.1 Battery aging

As pointed out by Wenzhong in [**17**], batteries usually have a short lifetime and high investment cost, and thus battery operation is a significant factor in the control of MG. A reduction of capacity to 80% of the rated capacity is commonly defined as the end of life (EoL) for batteries. In many cases, under 80%

of rated capacity the degradation of batteries will be accelerated and a sudden failure is expected due to several factors such as a high discharge rate.

As indicated by the authors of [18] and [19], to estimate the SoH of a battery two major aspects are considered: the cyclation based state of health and the calendrical aging.

Cyclical aging

As can be seen in Figure 5, battery lifetime can vary greatly depending on its usage. More profound discharges reduce the number of cycles a battery can perform.

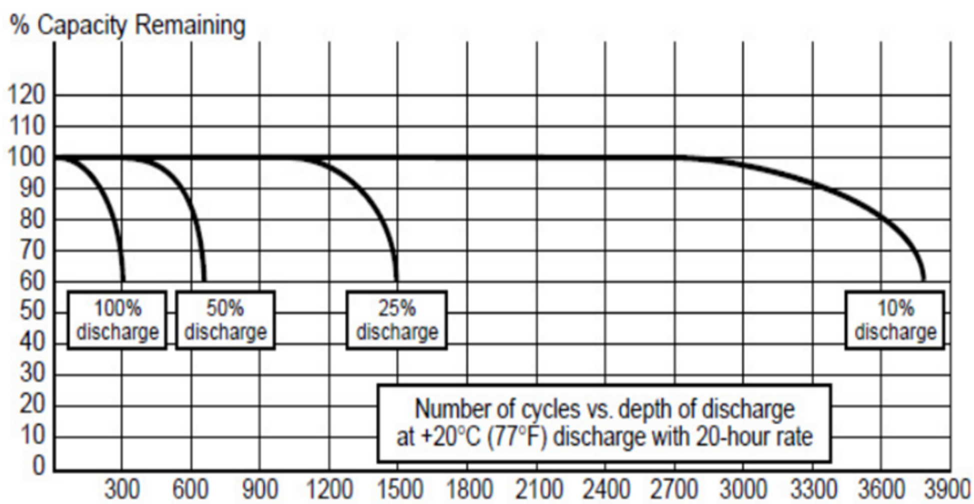

Figure 5: A typical cycling performance of VRLA batteries. [20]

There are two different approaches to battery degradation modelation and its consequent loss of life: Performance-based models and weighted Ah-throughput models.

Models based on simulating the change of performance values of the battery while the various aging processes take place are called performance-based models and are potentially very accurate for making technical and financial decisions.

In the performance-based models, the battery EoL can be expressed as a function of different performance parameters. These parameters, such as the battery voltage, current, uptake power, SoC, etc., can be modeled through various parameterized models. The performance is usually characterized using a battery model. The authors of [16] identify the most common models as:

• Electrochemical models

• Equivalent circuit models

• Analytical models with empirical data fitting

• Artificial neural networks.

Electrochemical models provide detailed information on local conditions and performance (e.g., temperature, potential, current, electrolyte concentration etc.). On the other hand, they require specific knowledge of the chemical and physical interactions, e.g., the porosity of the active materials, electrolyte volume and density, etc. Given the intrinsic complexity of this model, the computational speed of the simulation is low.

In equivalent circuit models, the battery is represented by components of an equivalent electric circuit, such as: voltage and current sources, resistors and capacitors. The aging process is represented by the change of the values of the equivalent circuit components.

In analytical models, with empirical data fitting, the lifetime is predicted by means of interpolation and extrapolation from test results and field data, which, in turn, require an extensive amount of data and experiments.

Artificial neural networks have a tremendous potential to discover unknown relationships between inputs (operating conditions) and outputs (aging processes and performance values). This approach to modeling does not rely on a detailed understanding of the mechanism which links input and output, but extensive data and measurements are needed to correctly derive the model.

All these models are potentially very accurate for making technical and financial decisions, but require extensive data, experimental parameters, laboratory tests, third or fourth order dynamical models, heavy computation or a combination of all of these elements.

Models which link the EoL of a battery to some parameters which can easily be determined such as number of cycles, Ah-throughput, and/or time since manufacturing are called cycle counting or weighted Ah-throughput models. Once a predetermined value of the parameter has been exceeded (Cycles, Discharged Ah, years or other), the battery is considered to have reached its EoL. These models are inherently limited in their accuracy but are the only models currently available for battery degradation for planning tools.

The weighted Ah-throughput models are based on the assumption that under particular standard conditions (e.g., temperature, DoD, discharge current, etc.) a battery can only achieve a given Ah-throughput when the EoL is reached. These models account for the fact that deviations from the standard operating conditions may increase or decrease the physical Ah-throughput a battery can give and consequently the rate of aging. A general presentation of an effective Ah-throughput model can be presented as:

$$Ah\_eff_b = \sum w_{b,E} \cdot Ah_E \quad (21)$$

Where Ah_eff_b is the weighted Ah-throughput or effective Ah-throughput that the battery can achieve before reaching its EoL, E is an event characterised by a particular instance of current, temperature, DOD and/or initial SOC, $w_{b,E}$ is the weigh or severity associated with an event E based on its specific conditions and Ah_E is the Ah-throughput over event E. The severity factor represents the relative ageing effect with respect to the baseline given by the nominal cycle. A severity factor greater than 1 represents conditions which are more severe than the baseline in terms of ageing and those below 1 are the opposite. The battery is considered to fail and reach its EoL when the effective Ah-throughput is equal or greater than the total Ah-throughput measured under nominal operating conditions as provided by the battery manufacturer.

Although these models are inherently limited in their accuracy, they represent a good option for the lifetime estimation of batteries due to their easy structure which allows for very high computational speed and adaptation to different battery technologies. The determination of the right parameters for the weighting factors remains a critical issue and accurate values of these factors would require extensive data collection. For the purpose of this thesis, the parameters will be extracted from battery manufacturer data.

Calendar aging

Calendar aging comprises all aging processes that lead to a degradation of a battery cell independent of charge-discharge cycling. The three main factors for the calendrical aging effect are battery temperature, SoC and non-operating time of the battery. The estimation of the aging effect for SoC and temperature is shown in Figure 6.

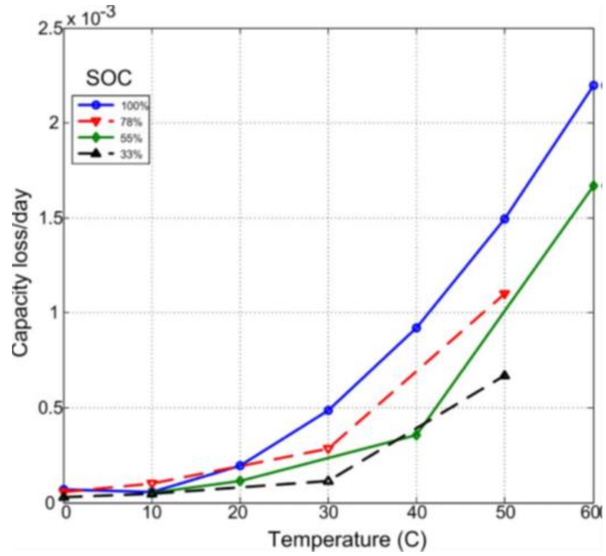

Figure 6: Battery capacity loss with temperature and SoC [**18**]

2.2.2.2 Peukert's Law

An observed phenomenon with batteries is their non-linear capacity, which can increase or decrease depending on the amplitude of the current. Peukert's law expresses mathematically this phenomenon "as the rate of discharge increases, the available capacity of that battery decreases". Peukert's equation is a convenient way of characterizing cell behavior and of quantifying the capacity offset in mathematical terms and can be written as follows:

$$t = H\left(\frac{C}{I \cdot H}\right)^{k} \quad (33)$$

where t is the actual time to discharge the battery, H is the rated discharge time, C is the rated capacity at that discharge rate, I is the actual discharge current and k is the Peukert constant, a constant for a given battery.

Equation (33) shows that at higher currents, there is less available energy in the battery. The Peukert constant is directly related to the internal resistance of the battery. Higher currents mean more losses and less available capacity. The value of the Peukert constant indicates how well a battery performs under continuous heavy currents. A value close to 1 indicates that the battery performs well; the higher the number, the more capacity is lost when the battery is discharged at high currents. The Peukert constant of a battery is determined empirically. For LA batteries the number is typically between 1.3 and 1.4. The

Peukert's effect can be seen in Figure 7, which shows that the effective battery capacity is reduced as the discharge rates increases.

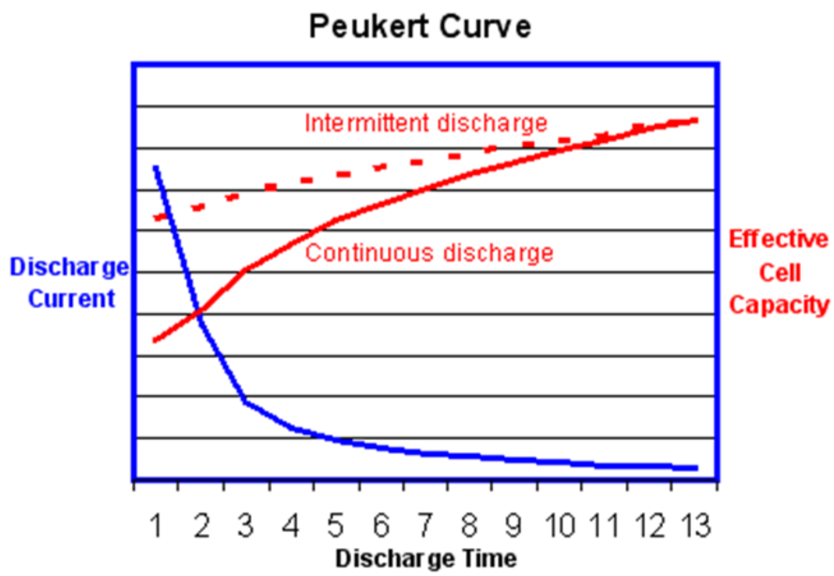

Figure 7: Peukert Curve [21]

2.2.2.3 Capacity fading

The energy storage capacity of a battery can be divided into three sections: the available energy that can instantly be retrieved, the empty zone that can be refilled, and the unusable part that has become inactive as part of use and aging. This inactive zone increases with the number of cycles and time, reducing the effective capacity. This is known as capacity fading. In most cases, a battery suffers linear degradation as shown in Figure 8.

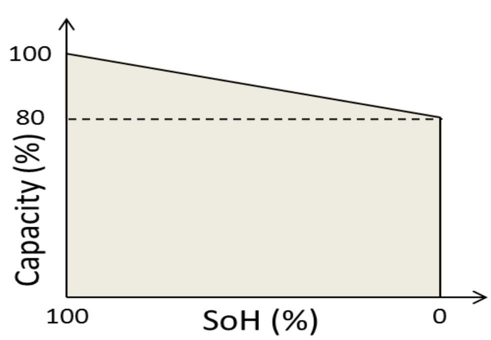

Figure 8: BESS capacity vs SoH.

When capacity reaches 80% or less of the initial one in a fully charged state the battery should be replaced. However, the EoL threshold can vary according to the use.

2.2.2.4 Self-discharge

All batteries are affected by self-discharge. Self-discharge is a battery characteristic, not a manufacturing defect. The amount of electrical self-discharge varies with battery type and chemistry. The energy loss is asymptotical, meaning that the self-discharge is highest right after charge and then tapers off.

As an example, nickel-based batteries lose 10–15 percent of their capacity in the first 24 hours after charge, then 10–15 percent per month. Figure 9 shows the typical loss of a nickel-based battery while in storage.

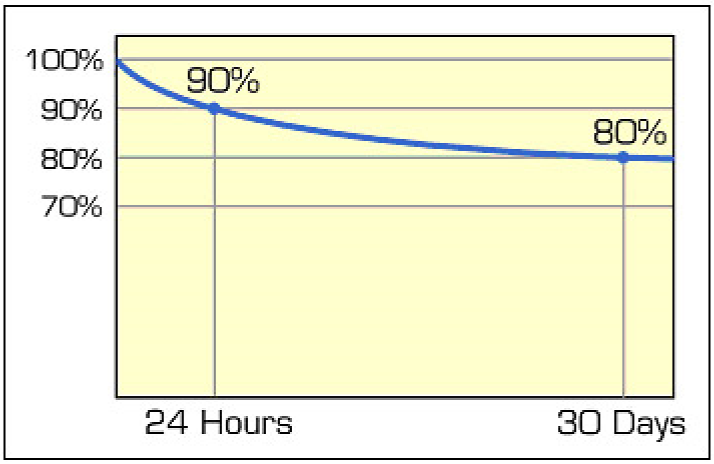

Figure 9: Self-discharge as a function of time. [**22**]

Table 1, based on the work presented in [**22**], summarizes the expected self-discharge of different battery systems.

Table 1: Self-discharge for different batteries

Battery system	Estimated self-discharge
Lead-acid	5% per month
Nickel-based	0-15% in 24h, then 10-15% per month
Lithium-metal	10% in 5 years
Lithium-ion	5% first 24h, then 4-5% per month

2.2.2.5 Battery charge

Depending on the technology used, a battery needs to be charged in a specific way. For example, LA and Li-ion charging operates under a constant current/constant voltage plan. First the charge current is constant and the voltage rises. When the battery reaches a set voltage limit, the charge voltage is fixed and the current drops until the battery can no longer accept further charge. Finally the float charge compensates for any loss caused by self-discharge. This is represented in Figure 10. On it the three stages are present: 1) Constant current, 2) Constant voltage or topping charge and 3) Float charge.

Nickel-based batteries charge with constant current, but the voltage is allowed to rise freely. Full charge occurs when a slight voltage drop is observed. A few chargers use rate of temperature increase over time to end the charge. A Nickel-based battery charge is presented in Figure 11. These charge schemes present a limit on the power a battery can charge.

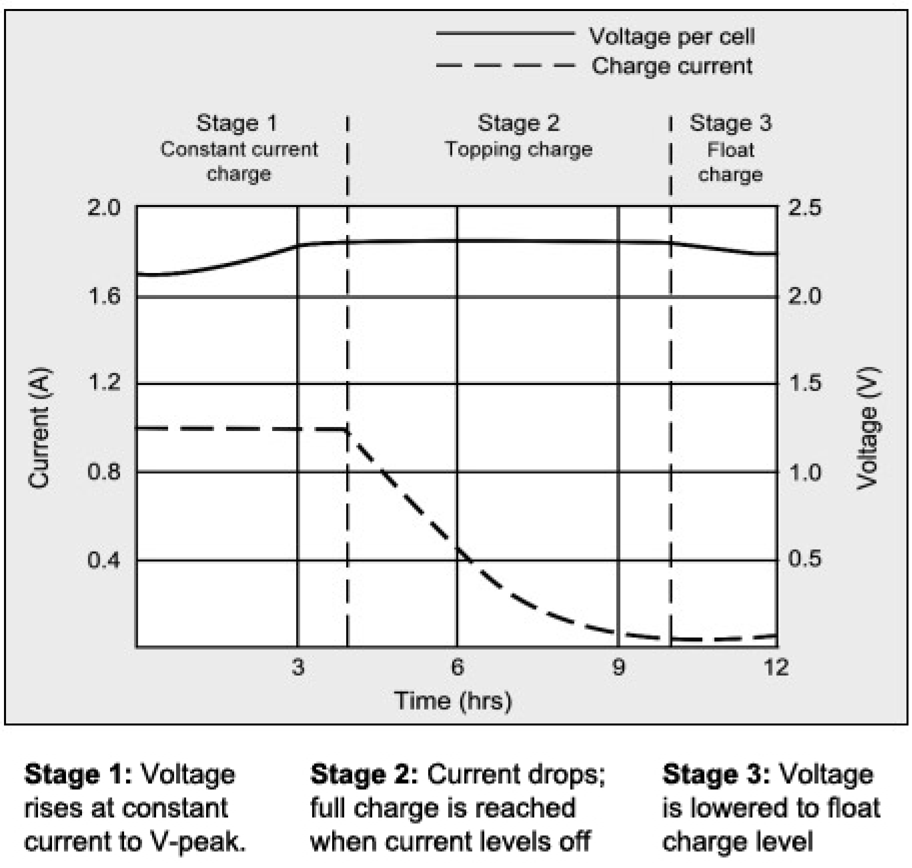

Figure 10: Charge stages of lead-acid. [22]

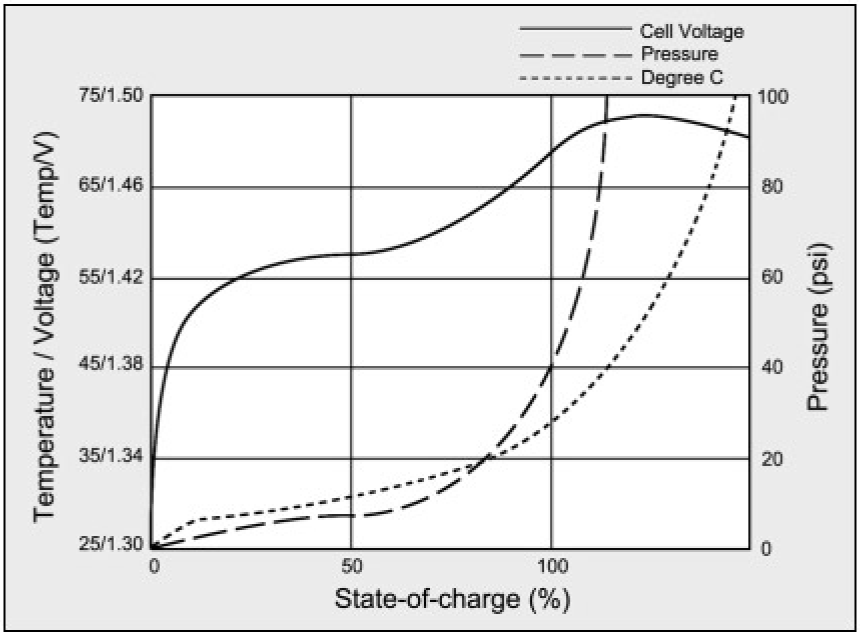

Figure 11: Charge stages of lithium-ion. [22]

2.3 MICROGRIDS

Electrical distribution systems are expected to undergo radical changes with the penetration of DER units. The availability of small, low-cost, power sources provides opportunities for radical change in the structure of power delivery. 35% of total US industrial electric power demand is met by on-site generation [**11**] and this trend is likely to accelerate. But the application of individual DER can cause as many problems as it may solve.

In the late 90s, the US Congress was concerned about the reliability of national electricity transmission and turned to the U.S. Department of Energy for guidance. Those initial meetings at the Energy Department led to the creation of a research and development team in 1999, called the Consortium for Electric Reliability Technology Solutions. The consortium drew on a list of nationwide specialists and was led by Bob Lasseter, a professor of electrical engineering at the University of Wisconsin-Madison. Early on, these researchers coined the term microgrid to describe their project. Soon, other power system specialists were engineering their own versions of microgrids. [**23**]

The first standard to support MGs, IEEE 1547.4 [**24**], was published in 2011 by IEEE Standards Coordinating Committee and titled "Guide for Design, Operation, and Integration of Distributed Resource Island Systems with Electric Power Systems". The document covers MGs in EPS that contain DER, providing alternative approaches and good practices for the design, operation, and integration of MGs.

The idea behind the term MG is system integration - treating all distributed generation and local load as a single, distributed system and presented to the main grid as single, well-behaved (complies with grid rules and does no harm) energy system that can operate both connected to the grid and as a stand-alone electrical island. [**11**]

This approach allows for local control of distributed generation. During disturbances, the generation and corresponding loads can separate from the distribution system to isolate the microgrid load from the disturbance (and thereby maintaining a high level of service) without harming the transmission grid's integrity. Intentional islanding of generation and loads have the potential to provide a higher local reliability than that provided by the power system as a whole. [**25**]

The main microgrid components include:

- Load

- DER
- Master controller
- Smart switches and protective devices
- Communication, control, and automation systems

2.3.1.1 Load components

MG loads are commonly categorized into two types: fixed and flexible (also known as adjustable or responsive). Fixed loads cannot be altered and must be satisfied under normal operating conditions while flexible loads are responsive to control signals. Flexible loads could be curtailed (i.e., curtailable loads) or deferred (i.e., shiftable loads) in response to economic incentives or islanding requirements.

2.3.1.2 DER components

MG's DER are either dispatchable or non-dispatchable. Dispatchable DG units can be controlled by the MG master controller and are subject to technical constraints depending on the type of unit, such as capacity, ramping, minimum on/off time, and emission limits. On the contrary, non-dispatchable units cannot be controlled by the master controller. Non-dispatchable units are mainly renewable DG, typically solar and wind, which produce a volatile and intermittent output power. The intermittency indicates that the generation is not always available and the volatility indicates that the generation is fluctuating in different time scales. These characteristics negatively impact the non-dispatchable unit generation and increase forecast error. Therefore these units are commonly reinforced with BESS. The primary application of BESS is to coordinate with DG to guarantee the MG's generation adequacy. The BESS plays a major role in microgrid islanding applications.

2.3.1.3 Smart switches and protective devices components

Smart switches and protective devices manage the connection between DER and loads in the MG by connecting/disconnecting line flows. When there is a fault in part of the MG, smart switches and protective devices disconnect the problem area and reroute the power, preventing the fault from propagating in the MG. The point in the electric circuit where a microgrid is connected to the grid, called the point of common coupling (PCC), is a switch that performs microgrid islanding by disconnecting the MG from the grid.

2.3.1.4 Communication, control, and automation systems

Communications, control, and automation systems are used to implement control actions and to ensure constant, effective, and reliable interaction among MG's components. [**12**]

The scheduling of a unit is performed by the MG's master controller, who coordinates the operation of the DER based on economic and security considerations. The master controller may determine the MG interaction with the grid, the decision to switch between connected and islanded modes, and the optimal operation of the local resources. [**26**]

A MG can offer more value to the grid than simply being a good citizen of the grid. A MG can provide a wide range of benefits and is significantly more flexible than backup generation, such as:

- Reduce frequency and duration of grid disruption through distributed energy resource management and self-healing at the local distribution network level.
- Manage growing demand without overloading or expanding existing electricity infrastructure. Controlled loads can be partially shed as necessary in response to changing grid conditions. [**8**]
- Supply electric power to areas where local utility is unable to provide reliable service or have access to customers.
- Reduce the physical distance between generation and loads, contributing to a reduction in T&D congestion, costs and losses [**27**]. Based on the analysis done by [**28**] the use of DG can reduce losses in the European transmission and distribution networks by up to 4%,
- Facilitate high penetration of DG without requiring re-design or re-engineering of the distribution system itself. The MG concept allows a reduced connection cost to DER units by placing many DER behind a single interface to the utility. This also increases the reduction in carbon emission by the diversification of energy sources [**28**]
- Postpone investments in new transmission and large-scale generation systems.
- Offer energy efficiency by responding to real-time market prices.
- Electrically isolate the MG (islanding) during disturbances (voltage fluctuation or blackout), maintaining a high level of service.
- Provide local premium power and ancillary services, such as local voltage support. [**8**]

2.3.2 CONTROL STRUCTURE FOR MG

In order to operate a MG in a coordinated manner, it is important to provide a controlled decision-making process in order to balance demand and supply coming both from the microsources and utility. Multi-level control scheme is widely accepted as a standardized solution for efficient MG management. [**29**], [**30**] and [**31**] propose that three control levels can be identified in a MG:

- Primary control
- Secondary control
- Tertiary control

Figure 12 shows the diagram of the control architecture of a MG with three control levels, which consists of local and centralized controllers and communication systems.

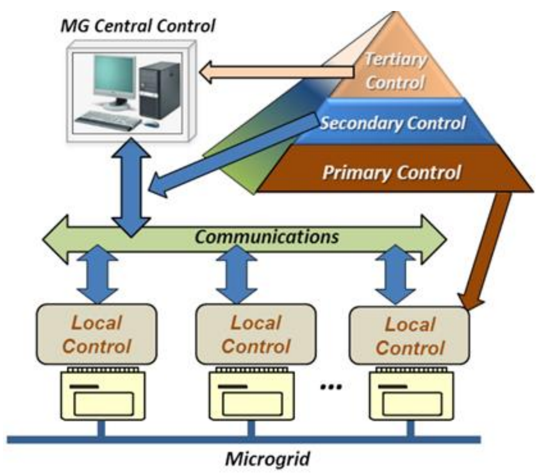

Figure 12: three level control [**29**]

2.3.2.1 Primary control

Primary control relies exclusively on local measurements, avoiding inter-unit communication for reliability. It is responsible for tracking voltage and current references, and power-sharing control for the adequate share of real and reactive power mismatches. It is composed of local microsource controllers and load controllers.

2.3.2.2 Secondary control

Secondary control is responsible for the reliable and economical local operation of the MG and sends the control output information for voltage and frequency restoration. This can be performed by an EMS or a microgrid central controller (MGCC).

2.3.2.3 Tertiary control

Tertiary control is responsible for the economic optimization of a connected MG, based on energy prices and electricity markets, for one or more microgrids. The tertiary control level, and correlated tertiary reserve allocation, is designed to optimize the dispatch of DER, energy and services exchange with the grid and to provide load balancing in a local power distribution network. Dispatch optimization can include economic, technical and environmental optimization. When connected to the grid, this control level takes care not only of the energy and power flows but also of the power quality at the PCC. The tertiary controller can also coordinate the power flow within the microgrid, by using an optimal power flow solver. [**29**]

The roles for primary, secondary and tertiary control level are summarized in Figure 13.

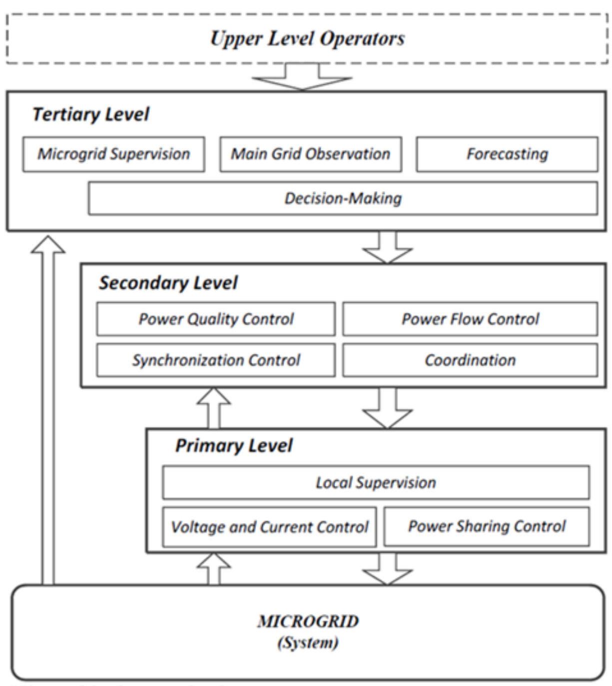

Figure 13: The three-level control roles [**30**]

There are multiple ways of implementing the same three-level control shown in Figure 13. As presented in [12] and [30], they are divided into four control structures (see Figure 14):

- Centralized
- Decentralized
- Distributed
- Hierarchical

The best choice of control structure changes according to the MG type (residential, commercial, military, etc.), and it's legal and physical features (location, ownership, size, topology, etc.). Each control structure has its advantages and disadvantages, which we will now explore.

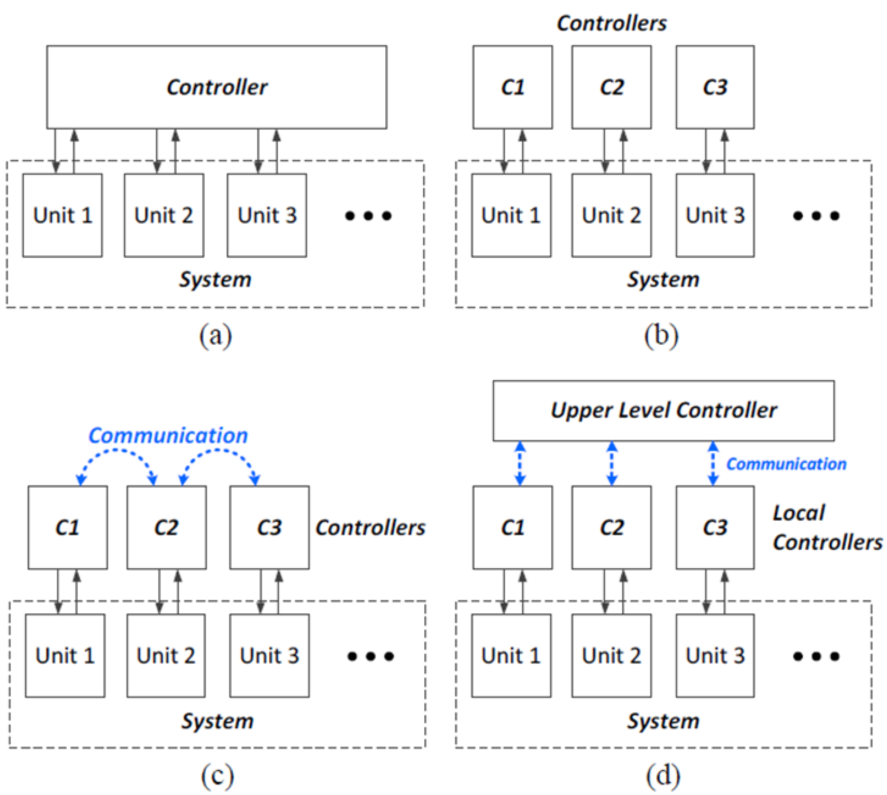

Figure 14: Control structures: (a) centralized; (b) decentralized; (c) distributed; (d) hierarchical [30]

2.3.2.4 Centralized control

Centralized control, presented in Figure 14 (a), requires data collection from all the essential MG's components. Based on the gathered information, control and management procedures can be executed in the controller to achieve proper and efficient operation. The advantages of centralized control include strong observability and controllability of the whole system, as well as standardized procedures and easy implementation.

However, it entails a single point of failure and the central controller breakdown will cause the loss of all functions. Other disadvantages are reduced flexibility and expandability (the central controller need reconfiguration with every new unit), as well as the necessity of considerable computational resources. Therefore, centralized control is usually more suitable for localized and small MG, where the information to be gathered is limited and centralized optimization can be realized with low communication and computation cost.

2.3.2.5 Decentralized control

Decentralized control in MGs, as shown in Figure 14 (b), refers to the control method which does not require information from other parts of the system. Each controller regulates its respective unit with only local information. The main responsibility is given to the controllers of each DG that competes to maximize its production in order to satisfy the demand and possibly provide the maximum possible export to the grid, taking into account market prices [**31**].

DG might have different owners; in such a case decisions should be taken locally, making this a good solution. Decentralized schemes also have the advantage of not requiring real-time communication, even though the lack of coordination between local regulators limits the possibility of achieving globally coordinated behaviors.

2.3.2.6 Distributed control

Distributed control is similar to decentralized control. Each controller regulates its respective unit, but using communication technologies (WiFi, Zigbee, etc.) and information exchange algorithms (Peer to peer, gossip, consensus etc.) some functions provided by centralized control scheme can also be realized in a distributed way, as shown in Figure 14 (c). The controllers ‘talk’ with each other through communication lines so that essential information is shared among each local system in order to facilitate a coordinated behavior of all the units.

The main challenge of a fully distributed control scheme is the coordination among distributed units to fulfill either the control or optimization objectives, with only partial communication. While associated information is limited to only a few quantities in case of secondary control, tertiary control may need to exchange a number of different signals with neighboring agents. The number of transmitted messages between different individual components and the MG's controller increases as the size of the MG increases, necessitating a larger communication bandwidth. [**12**]

2.3.2.7 Hierarchical control

Hierarchical control, as shown in Figure 14 (d), implements simple functions in the local controllers to guarantee a basic operation of the system. Advanced control and management functions are implemented in the central controller. This enables the advantages of decentralized (operation even without communication) and centralized (coordinated operation). For these reasons, hierarchical control is becoming a standardized configuration in MG.

Primary control, including a basic voltage/current regulation and power sharing, is usually implemented in local microsource and load controllers. Secondary control (compensating steady-state deviations in voltage and frequency) and tertiary controls (economic considerations and power flow between MG and utility) are conventionally realized in a centralized manner, a MGCC responsible for the maximization of the MG value and the optimization of its operation that requires global information from all the essential units. Microsource controllers follow the demands from the MGCC, when connected to the power grid, and have the autonomy to perform local optimization of the microsource's active and reactive power production, and fast load tracking following an islanding situation [**30**], [**31**].

2.3.3 CONNECTED AND ISLANDED MG

As previously mentioned, a MG can operate in two modes: grid-connected and islanded.

In grid-connected mode, a MG can trade power with the EPS. In the islanded mode the MG operates autonomously, without connection to the utility grid, and must rely on its own generation and reserves.

Islanding is typically performed to rapidly disconnect the microgrid from a faulty distribution network to safeguard the MG's components from upstream disturbances and allow an uninterrupted supply. The

MG is islanded from the grid using upstream switches at the PCC, and the local loads are fully supplied using local resources. After islanding, the reconnection of the MG is achieved autonomously after the tripping event is no longer present.

Characteristics of the MG such as two-way power transfer, the presence of DG, DR, switching between the modes and control of the MG in each operation mode are challenges that need to be solved to use the MG efficiently and fully realize it's potential.

2.3.3.1 Connected mode

From the grid's point of view, a connected MG can be regarded as a controlled entity within the power system that can be operated as a single aggregated load, and even as a small source of power or ancillary service supporting the network, given adequate remuneration is provided.

A MG operated economically in grid-connected mode should ensure sufficient available resources in case the MG is required to switch to islanded mode.

2.3.3.2 Islanded mode

The work presented in [**11**] indicates that in traditional systems a load step of 20-25 percent compared to a generator rating is considered large, causing significant transients. Operation in island mode compounds the problem of transients for a MG. This implies that a MG the generation needs to respond to larger than normal load changes (50-60%) without causing problems for the load and system.

The basic system needed for island operation is;

- Storage to allow for adequate fast load tracking.
- Fast DER units to ensure the energy requirements of the loads can be supplied during the first few cycles after islanding. [**32**]
- Stable ac voltage control provided through capacitors and inverter action. [**11**]
- Voltage and/or frequency control methods for sharing between DER units.

DER unit control can be programmed to operate in different modes (base-load, load power dispatch, etc.) under normal grid paralleled conditions. In islanded mode, the MG requires a high level of coordination among the DER participating in control tasks, which makes centralized and hierarchical control approach the most suitable for this application. When forming an islanded system, it may be necessary to switch from one control mode to another when separating from the EPS. The DER units may have to switch voltage control, switching from a passive control that follows the system voltage (per [**24**] requirements) to an active control that maintains the voltage of the islanded system.

A MG with islanding capacity can also be used to supply electricity to a community disconnected from the grid due to economic issues or geography position.

2.3.4 DEMAND RESPONSE IN MG

In power systems, two kinds of security actions can be defined: preventive and corrective.

Preventive security actions ensure that in the event of a contingency enough resources are available for the quick execution of security actions that guarantee the normal operation of the system once the contingency has taken place. Examples of preventive actions include starting extra generating units or the redispatch of already committed units.

Corrective actions include the fast redispatch of generation units or the curtailment of selected loads under a specific contingency.

Several smart grid papers, such as the work presented in [**8**], have focused on this last concept, known as demand response. It explores how to involve the consumer in the active operation of the power balance by introducing technical operation systems and/or economic incentives to facilitate flexible demands, including the development and design of proper information and communication systems.

DR can offer a variety of financial and operational benefits for electricity customers, load-serving entities (whether integrated utilities or competitive retail providers), and grid operators. In particular, DR can be an effective tool in providing balance between supply and demand in real-time. Traditionally, such services, known as ancillary services (AS), are provided by utility-owned operating reserves (spinning and non-spinning) which are typically generators with flexible capacity, available when needed, to maintain secure operation of power systems. From an economic perspective, these services and reserve power are costly and any method which manages to reduce the magnitude of these services without sacrificing system stability is of significant importance.

Demand resources are defined as a subset of non-spinning reserves and must be available within 10 min or shorter from the time they are called upon. This capability can be technically and economically achieved through responsive electric devices such as electric water heaters equipped with hot water storage tank. DR resources provide a reliable, low cost, environmentally-friendly alternative to conventional spinning reserves. DR can also provide other AS which grid operators, utilities or other entities can use. These entities can control customer controllable loads to shift or reduce their load profile or respond to excess or insufficient renewable generation.

Although it may seem likely that a single demand resource may have a high failure rate to curtail load on short notice, the aggregation of many small resources into one large resource makes it more probable that the assigned response will be achieved. This characteristic of demand resources potentially makes DR's resources more reliable than conventional generation, where the failure of a single generator to start can cause the loss of considerable spinning reserve capacity.

2.3.5 MULTI-MICROGRID

A MG typically has a small total capacity. The capacity of a typical microsource is between 10 and 100 kW. As a result, the total capacity of a microgrid typically does not exceed 1 MW. There is usually no restriction on the quantity of energy for the spot or bilateral market, but most ancillary markets require 1–2 MW for primary reserves and 10–20 MW for secondary and tertiary reserves

With a total capacity of 1 MW per MG, the practical realization for supplying AS would be to use the combined capacity of multiple microgrids. This concept is called Multi-Microgrid (MMG). An example of a MMG proposed in [**33**] is shown in Figure 15. MG management will be further discussed in the next section.

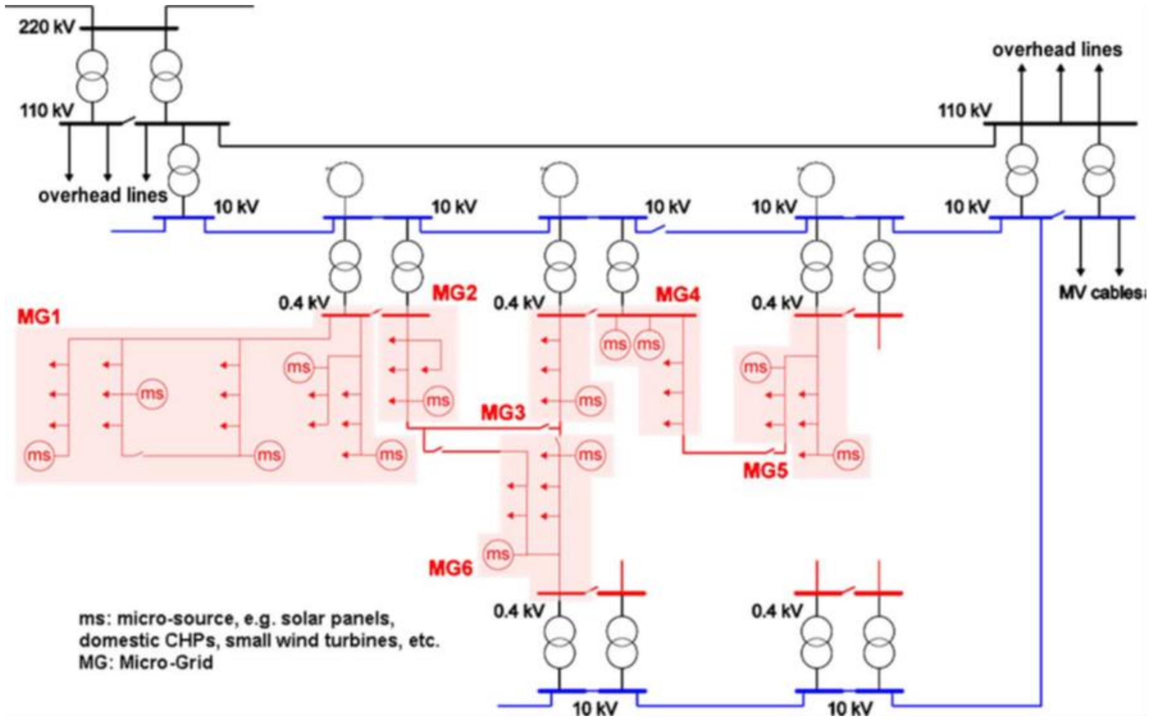

Figure 15: Multi microgrid example. [**33**]

2.4 MICROGRID MANAGEMENT

MG management is subject to a variety of operational constraints such as energy balance, load management, and DER limitations. MG management has to determine the amount of power that the MG should draw from the distribution system and each of its own units based on an optimized operation, achieved by sending control signals to the DER and controllable loads in the MG.

An EMS is a "supervisory controller" that meets these operational objectives and constraints. The EMS provides the dispatch of power and voltage set points to each microsource controller. Typically the optimization process is divided into two levels, as indicated in [**29**]:

1) Energy optimization: The energy can be optimized day(s) ahead, according to the generation and load forecasts. A (sub)optimal solution can be found, depending on the accuracy of the forecast and security information, based on an objective cost function that may contain information that related to energy generation costs, revenues, CO_2 emissions, efficiency, among others.

2) Power flow optimization: Known as optimal power flow (OPF), the reactive power can be optimized in real-time to achieve optimum power flow based on the energy optimization.

To provide an optimal schedule, the EMS considers load consumption, renewable resources, state of the electrical distribution system, energy and thermal costs, and the charging/discharging features of the BESS in order to achieve economical operation, while guaranteeing that electrical and operational constraints of the system are satisfied. A typical EMS architecture is shown in Figure 16.

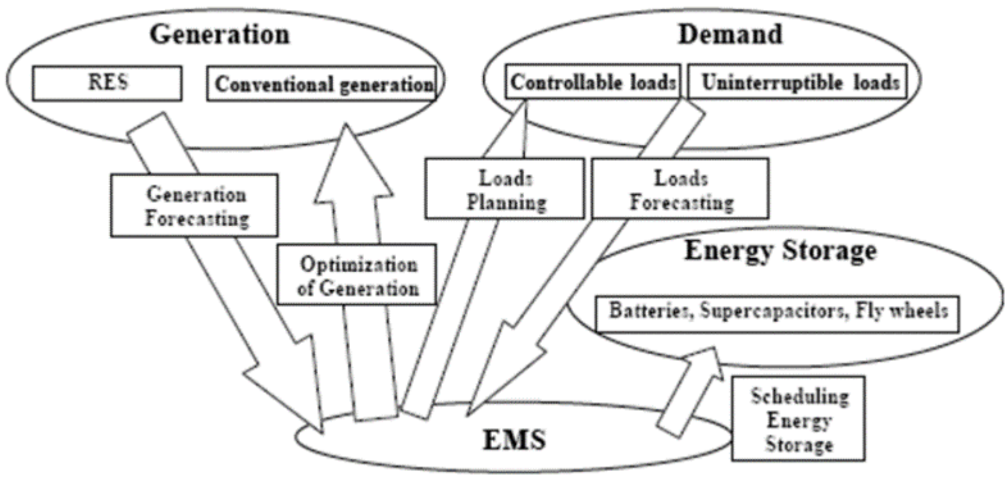

Figure 16: A typical EMS architecture [**34**]

The EMS can make decisions while monitoring conditions of the MG components and with updated information. Thus, the EMS is informed about MG contingencies in real-time and can modify its previous decisions related to power traded with the main grid, solar power production, and power load shedding or shifting, among others.

To obtain each unit dispatch, the EMS includes an optimization program formed by the algebraic formulation resulting from the modeling of the MG units and a numerical solver. According to [**12**] a variety of scheduling approaches have been proposed to solve the microgrid scheduling problem, including: deterministic methods, heuristic methods, expert system and stochastic methods.

The main focus of deterministic methods is on constrained optimization problems. The system operation is described mathematically as an objective function to be maximized or minimized. Constraints on variables are included, which represent limitations inherent to the units. The problem to solve is then to determine the state (a set of allowable variable values) that results in the maximum or minimum objective function without infringing on any of the constraints.

If a system can be approximated to fit into certain mathematical structure, specific theory and algorithms can be applied. The fastest and most certain results come from systems that can be described as linear programs. The objective function and constraints of a linear program must all be linear equations. Nonlinear systems add additional complexity. Algorithms for nonlinear systems have been tailored to systems that can be described as quadratic objective functions[1] with linear constraints, separable systems[2], or convex systems[3]. Algorithms for more general non-linear programs also exist.

These algorithms exploit the knowledge of the structure of a system in order to only consider a small fraction of all the possible states instead of using the brute force of enumeration (evaluating every allowed state). Some of these algorithms are: advanced primal-dual interior point method based on nonlinear programming [**35**], Mixed Integer Linear Programming (MILP) [**36**], [**37**], [**38**] [**39**] [**40**], sequential quadratic programming [**41**], subgradient search [**42**], reduced gradient search [**43**], quadratic programming and linear programming [**44**], [**45**] and interior point method [**46**].

MILP is a modification of the standard integer programming that treats the objective and constraint functions as continuous, and some variables as integers. This enables the incorporation of both binary and continuous decision variables, such as when to turn on a unit and at how much power. For example: when to start a unit and how much power to inject with it.

MILP problems are generally solved using a linear-programming based branch-and-bound algorithm. This method finds the optimal solution to a "relaxed" problem without the integer constraints. If in this relaxed solution the decision variables with integer constraints have integer values, then the optimal solution has been found. If one or more integer variables have non-integral solutions, the Branch & Bound method chooses one such variable and "branches," creating two new subproblems where the value of that variable is more tightly constrained. These subproblems are solved and the process is repeated, until a solution that satisfies all of the integer constraints is found.

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[1] Quadric equations consist of a sum of terms in which variables appear in terms as squares (x^2) or products of two different variables (x_1x_2)

[2] In separable systems, equations and inequalities are the sum of individual terms that are functions of only one variable per term (such as 2x, x^3, 12/x, but not x_1x_2)

[3] In convex systems, equations and inequalities are the sum of individual terms that are convex functions. Convex functions are those that always curve upward (positive second derivative)- i.e. a local minimum is guaranteed to be the global minimum. Linear functions are also convex functions

The advantage of MILP is its ability to find a solution with a "proven optimality", its simplicity and ease of use. As NP-hard, the number of combinations grows exponentially with the size of the problem. This makes MILP an ideal tool to solve MG problem's, which tend to be small in size but require a reliable solution in a short time.

2.4.1 UNCERTAINTY AND ROBUST STRATEGIES

Management of uncertainty in the dispatch is a challenging problem that requires the application of additional techniques and the inclusion of more information for less risky decision process. For MG the management of uncertainty is of critical importance, given the demand-supply balance that depends on DER during unexpected grid disturbance. Thus one of the main aspects of this thesis is the management of uncertainty.

Most published works on energy management systems focus on deterministic microgrid operations [**47**]- [**48**], but renewable generation and demand forecast in microgrids are uncertain. The difference between a deterministic dispatch and a stochastic one is presented on Figure 17.

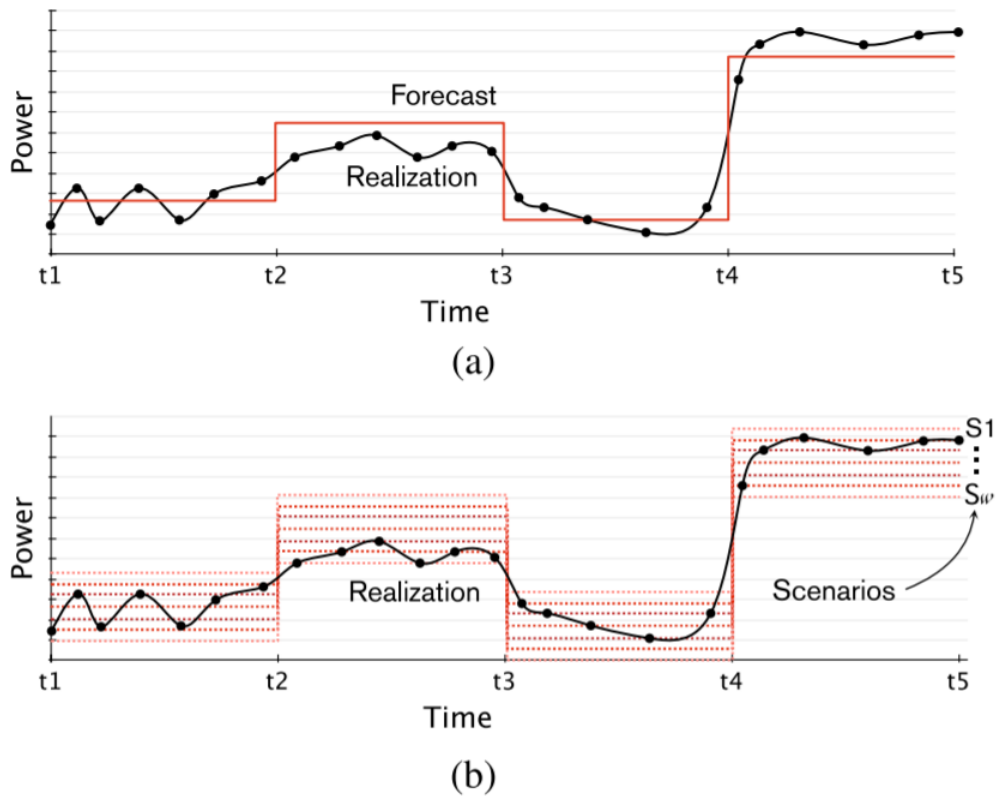

Figure 17: Deterministic (a) and stochastic (b) approach. [**49**]

As indicated in [**50**], the issue of uncertainty has already been widely researched in transmission-level energy management. According to the authors of [**49**], the most common approaches can be classified under the following four categories:

1) <u>Deterministic with Close Tracking</u>: This methodology consists of a close tracking of the realization of uncertain variables in the problem with small time steps (i.e., 5-min), solving the dispatch problem using the most current information, such as the work done in [**47**]. Most prediction tools for renewable resources and load have an uncertainty that increases in time. Thus this approach handles uncertainties indirectly by frequently updating solutions in small time steps, in order to closely follow the changes in uncertain variables. However, this approach requires the forecasts to be refreshed at every calculation and recurring optimization, making this type of method very data and resource intensive.
2) <u>Robust Optimization</u>: In this technique, a suboptimal solution is obtained by optimizing the decision variables considering worst case scenario given an uncertainty set, the size of this set is adjusted to balance optimality and robustness [**51**]. There are important challenges related to selection of the uncertainty set. If not adequately defined, the uncertainty set may lead to computationally intractable problem formulations.

3) Chance-Constrained Optimization: This method assumes that the uncertain variables have a known distribution functions, or can be approximated by a limited number of scenarios, and minimizes the dispatch cost in a single stage approach [**52**]. These models include constraints that hold with some level of probability instead of a holding surely. Choosing high levels of confidence requires an accurate representation of the uncertainty variable for meaningful results.
4) Two-Stage Stochastic Optimization: This method breaks down the problem into two stages. The formulation of the first stage minimizes the current cost plus the expected value of future actions based on a finite number of second-stage realizations, in such a way that first-stage variables must guarantee feasibility for all second-stage scenarios [**52**]. By design, the stochastic EMS formulation should produce higher commitment costs (first-stage decisions) and lower dispatch costs (second-stage decisions), yielding lower total costs in the long term. This approach may lead to large-scale problems if too many realizations are required.

To implement these methods, various different novel techniques have been introduced by researchers for managing the uncertainties in microgrids. Sensitivity analysis [**53**], fuzzy logic-based optimization [**54**], stochastic optimization techniques [**55**], and robust optimization ([**56**] [**57**] [**58**] [**59**]), rolling horizon [**47**] and Bender's decomposition [**60**] are among the most cited techniques available in the literature for uncertainty management in scheduling of distribution systems and MG.

Bender's decomposition is a technique in mathematical programming that allows the solution of very large linear programming problems that have a special block structure, such as the ones in power systems. As explained in [**60**], this block structure often occurs in applications such as stochastic programming, where the uncertainty is usually represented by scenarios.

The strategy behind Bender's decomposition can be summarized as divide-and-conquer. That is, in Bender's decomposition, the variables of the original problem are divided into two subsets (master & slaves) so that a first-stage master problem is solved over the first set of variables, and the values for the second set of variables (slaves) are determined in a second-stage subproblem for a given first-stage solution. If the subproblem determines that the fixed first-stage decisions are in fact infeasible, then so-called Bender's cuts are generated and added to the master problem, which is then resolved until no cuts can be generated.

2.5 MG SERVICES AND MARKET OPPORTUNITIES

There are several economic opportunities for MGs, as long as they can participate in the local electricity market. A MG can play an important role in the operation of the transmission system providing benefits for sub-transmission and transmission systems, as explained in [**61**]. Such benefits can be provided through so-called AS.

AS are a part of power markets, with the objective of supporting the basic services of generating capacity, energy supply and power delivery. The existence, definition, and pricing of AS is a function of each specific grid itself and the regulation of its energy market. For example, the Federal Energy Regulatory Commission defined AS as “those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system” and the North American Electric Reliability Council uses a similar definition “services necessary to affect a transfer of electricity between Purchasing and selling entities, and that a transmission provider must include in an open access transmission tariff”.

The MG not only can buy electricity from the EPS, it can also interact in various ways with it and its electricity market, summarize in Figure 18. From the top to the bottom, the light blue box represents a single MG agent or MG aggregator that manages multiple MGs, each potentially with its own optimization algorithm.

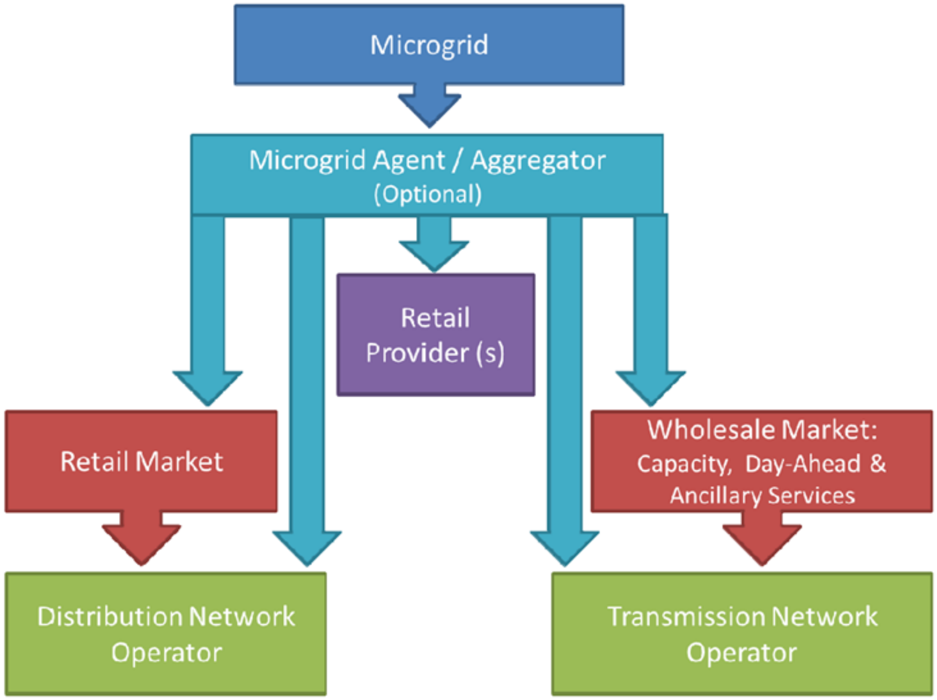

Figure 18: MG and EPS interactions. [62]

MG agents can participate in the wholesale market that can be broken down into the capacity market, the day-ahead energy market and the ancillary services market. By aggregating DER units, MGs are able to bid and offer energy and ancillary services to the external system.

Studies show that DG and MG can provide ancillary services. In [63], technical advantages when DG are used for reserves of active and reactive power are shown; and a discussion of ancillary services for DG connected to the network is performed in [64]. Much of the research on reactive power pricing is based on marginal cost theory. Discussions on the implementation of this theory to price reactive power were provided in [65], and detailed cost models of reactive power support can be found in [66]. Based on study [67] by SANDIA, auxiliary services represent an enormous opportunity for ESS and thus MG for additional revenue. In this study and using data from 2010-2011 from the California Independent System Operator, the revenue for a BESS was quadruplicate when comparing only offering arbitrage and offering arbitrage with ancillary services. A more detailed exploration of the services a MG can offer is presented on the next section.

A relevant aspect discussed by [68] is the MG limited total capacity. The capacity of typical micro-sources is 10-100kW. As a result, the total capacity of a microgrid can be around 1MW. The minimum power in the Union for the Coordination of Transmission of Electricity (The synchronous interconnection of central European countries) for different ancillary markets is 1–2 MW for primary reserves and 10–20 MW for secondary and tertiary reserves [**69**]. With a total capacity of 1MW per MG, the more practical realization of supplying AS would be to use multiple microgrids for primary reserves. For example, to provide a 1MW bid, it would require 10 micro-sources of 100kW, when all of their capacity is only used for the primary reserves market. In practice, only a proportion of the capacity is used for reserves and depending on the type of technology the maximum amount of capacity reserve can vary.

MG can be compensated for these services via fixed payments, payments for service availability, payments based on frequency of usage, and/or payments based on lost opportunity cost. This last is the revenue that the microgrid could have made but was not able to because it had to be available for the main utility grid even if it was not called upon.

There have been several studies exploring the possible services that a MG can offer on different markets or electric power systems, such as [**8**], [**62**], [**70**], [**17**], [**71**], [**72**] and [**73**]. These works identify the following services a MG can offer:

- Arbitrage of energy
- Demand side management/demand response
- Load leveling
- Peak shaving/shifting
- Reduction of transmission losses
- Improved reliability
- Reduction of emissions
- Enhancing power quality (Spinning Reserve & voltage support)
- Deferring investment and upgrade costs by congestion relief of T&D.
- Black-start reserve provision & system restoration support.

2.5.1 ENERGY ARBITRAGE

The wholesale cost of energy is increasingly volatile. The additional electricity to meet the surge in afternoon and early evening is generally supplied by natural-gas or diesel powered “peaker” plants. And these plants are expensive to operate. They only generate for a few hours each day, so their construction costs are amortized over a smaller amount of electricity. The difference in price per kWh between low and high demand can be more than double, as shown in Figure 19, a modified version of what is presented on the online article [**74**] discussing storage and arbitrage.

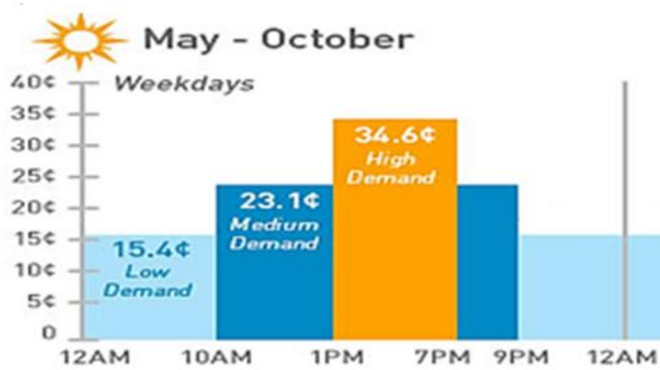

Figure 19: Energy price during a typical day during May-Oct in California [**74**].

As long as a MG can participate in the wholesale market, the MG ESS can exploit this difference in price by loading up on cheap energy when renewable generation is high or in moments where the least expensive baseline generators are operating and sell this energy at premium prices during peak hours. The difference in cost between buying the energy at a low price and selling it when it is in high demand will provide the MG with direct revenue, as long as the cost of performing this service is lower than the revenue obtained.

2.5.2 DEMAND SIDE MANAGEMENT

Traditionally, power generation increases in response to an increase in load. The concept of demand-side management (DSM) includes both energy efficiency and DR, thus working from the other side of the equation, from the consumer perspective.

DSM programs encourage consumers to modify their pattern of electricity usage, giving them different incentives to reduce consumption. This can be used to compensate for a reduction in generation or an increase in electrical consumption without requiring a change in the operating units. DSM is defined by the U.S. Department of Energy as “changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized".

Energy prices are subject to constant fluctuations, based on the time and location of consumption/generation. Fluctuating energy prices stimulate DSM in microgrids to shift loads away from high price hours toward lower price hours, reducing the MG operational cost.

By shifting load, DSM can have several economic, environmental, and reliability benefits. The authors of [**12**] identify the following possible effects: reduce costs, alleviate electrical system emergencies, reduce the number of blackouts, increase system reliability, and defer high investments in generation, transmission, and distribution network capacity.

From a market perspective, the authors of [**62**] identify four incentives for DR:

- Demand bidding
- Emergency DR
- Capacity market
- Ancillary services market

2.5.2.1 Demand bidding

Demand bidding, also known as capacity bidding (CB), refers having a MG or MG aggregator bid a specific load reduction in the day-ahead energy market, and if the bid is less than the market price, then the MG should curtail its load by the amount specified or face a penalty. Demand bidding programs are typically offered by utility companies which act as an aggregator in the regional market, and the minimum bid amounts are in the tens of kilowatts per hour. The microgrid could participate directly in the day-ahead regional energy market too.

2.5.2.2 Emergency DR

An emergency DR program is run by the market and transmission system operator (TSO), who commonly is one integrated independent entity, and the MG participant is remunerated for a measured load reduction during emergency conditions.

2.5.2.3 Capacity market

Similar to emergency DR, capacity market programs are run by the market and TSO, and the MG participant is remunerated for a measured load reduction during emergency conditions. The difference between this program and emergency DR is that in the capacity market, the MG has to pre-specify the amount of load reduction it offers for a year, and if cleared, it will get paid at a capacity clearing price.

2.5.2.4 Ancillary services market

Finally, the ancillary services market allows a MG to bid load curtailment in the spot market as an operating reserve. An operating reserve in very general terms is a capacity used to maintain the active or real power balance of the power system. Once again, when bids are accepted, microgrid participants are paid the spot market price for committing to be available and are paid spot market energy price if load curtailment is required.

The authors of [**75**] divided the different loads into three categories:

- critical
- curtailable
- re-schedulable

2.5.2.5 Critical demand

Critical Demand describes loads that must be met at all times, such as servers and loads related to essential processes. A MG must meet all critical loads in preference to any other load, and possibly without regard to cost. Note that if a microgrid does not have special demand control capabilities, then all loads are viewed as critical loads. Critical loads may be prioritized in the event that load shedding is required due to supply limits.

2.5.2.6 Curtailable demand

Curtailable demands have a preferred level, but the demand level can be lowered if a certain cost is associated with the load reduction. For example, air conditioning operates at a temperature setpoint requiring a certain chiller load. If the setpoint is raised, a warmer indoor building temperature ensues and lowers occupant amenity. During times of particularly high electricity prices, the cost of this incremental discomfort may be outweighed by the incremental cost of electricity purchase. Curtailable loads could be specified by the following parameters:

- Full load demand,
- Percentage of load that can be curtailed,
- Cost of curtailment,
- Lead time needed before curtailment can begin,
- Ramp rate at which load can go down,
- Length of time for which load can be curtailed, and
- Maximum frequency of curtailments.

2.5.2.7 Re-schedulable demand

Re-schedulable demand may be flexible in their scheduling and can also involve shifting the execution of some energy-intensive activities to later in the day, or further into the future. An example of this would be pre-cooling a building during the less energy intensive (and less expensive) hours of the morning rather than waiting to start cooling until there is a cooling demand. Re-schedulable loads could be specified by the following parameters:

- Load demand,
- Maximum length of rescheduling time, or acceptable time to reschedule,
- Cost of rescheduling,
- Lead time needed before rescheduling can take effect, and
- Rate at which load goes down once it is rescheduled.

With greater penetration of electric vehicles each year, the amount of controllable loads is expected to increase over the next years.

2.5.3 EMISSION REDUCTION

Carbon dioxide emissions are regarded as one of the main causes of global warming. In the framework of the Kyoto Protocol, many countries, and regions, in the process of institutional innovation and design, attempt to fulfill their emission reduction commitments by means of the market mechanism under government guidance.

Emissions reduction benefit is based on the fact that renewables-based DG units have lower emissions per kWh than conventional thermal generation. In [**72**] the authors identify the reduction of emissions generated by a MG as:

$$\Delta E = E_{BC} - E_{MG} = \sum_{t}^{T} [P_{GP}(t) E_G(t)] \Big|_{BC} - \sum_{t}^{T} \left[P_{DG}(t) E_{DG} + \left(P_{GP}(t) - P_{GS}(t) \right) E_G(t) \right] \Big|_{MG}$$

Where E_{BC} and E_{MG} are the emissions in the base case and MG case, respectively, t is the time step (in hours), P_{GP} and P_{GS} are the power purchased from and sold to the grid, E_G is the marginal rate of emissions from the grid at time t (in tCO_2/kWh), P_{DG} is a vector containing the power produced by each DG unit and E_{DG} is a vector containing the emissions rate of each DG unit.

The rate of emissions is a direct result of burning fossil fuels to convert into electric energy and depends on the fuel used, the level of power, and the efficiency of the technology used in the power plant operation. A method to calculate displaced emissions is presented in Annex I.

2.5.4 SPINNING RESERVE

The EPS is unique in that power production and consumption must be matched instantaneously and continuously. The unexpected loss of generating units or transmission lines result in sudden imbalances between generation and consumption. Such imbalances lead to frequency deviations from the nominal frequency of the power system. Therefore, an electric power system needs reserve power to counter such deviations.

Power systems typically keep enough reserves available to compensate for the worst credible contingency (ex. loss of the largest generator). Typically these services are divided into active power support, for frequency regulation, and reactive power support, for voltage regulation.

2.5.4.1 Frequency or active power support

Consumers needs for higher power quality have significantly increased during the past decades due to the growing application of voltage sensitive loads, including a large number and variety of electronic loads and LEDs. Utilities are always seeking efficient ways of improving power quality issues by addressing prevailing concerns stemmed from harmonics and voltage.

In accordance with the European Network of Transmission System Operators rules [**76**], there are three types of reserve; Primary, Secondary and Tertiary reserve. The unique characteristics for each level of reserve are shown in Table 2.

Table 2: Classification of control power reserves. [**77**]

	Primary	Secondary	Tertiary
Activation	Automatic, locally	Automatic, centrally	Manual, centrally
Start Fully activated End	3-5 sec ≤15-30 sec ≥15 min	≤30 sec ≤10-15 min As long as required	No ≤15 min As agreed
Minimum single bid (MW)	1-2	10	10
Payment	Availability	Availability, utilization	Utilization

As described in [**78**], primary frequency control is a local automatic control that adjusts the active power generation of generating units and the consumption of controllable loads in order to restore quickly the balance between load and generation and counteract frequency variations.

Secondary frequency control is a centralized automatic control that adjusts the active power generation of the generating units in order to restore frequency and power flow in interconnections with other systems to their target values following an imbalance. In other words, while primary control limits and stops frequency excursions, secondary control brings the frequency back to its target value.

Tertiary frequency control is related to manual changes in dispatch and commitment of generating units.

During the last decade, markets for frequency balancing reserves have been established in many European countries (Germany, Denmark, Scandinavian countries, etc.) and in the USA (e.g. PJM). Under free market conditions, MG operators have the right to offer primary frequency control reserves as long as they fulfill technical grid code requirements set by the TSO. The TSO pays for the mere availability of reserve power. There is no utilization payment proportional to the actual amount of energy supplied or consumed. All reserve suppliers are paid a fixed price for the whole tendering period (day, week, month, etc.) per kW of contracted reserve. Primary frequency control is typically remunerated based on availability [**77**].

In some markets, the participants can contribute toward system security by offering to sell both up and down-spinning reserves at different rates, not just the same value for both.

2.5.4.2 Voltage or reactive power support

Various actors need reactive power for different purposes, the reactive power supply is essential in order to maintain system security. In the EPS, reactive power is typically consumed by three entities, loads, power generators, and the network, and it is used to regulate voltage.

. Reactive power cannot be provided remotely and a deficiency causes power losses, voltage decay, and poor equipment utilization in networks [**79**]; therefore, supplying reactive power locally is necessary.

The underlying relationship between reactive power and voltage is the following: an increase in reactive power consumption leads to a voltage drop and vice-versa. Insufficient reactive power supply decreases the voltage, forcing the current to increase to serve the active power required by loads, which leads to further reactive power consumption in the lines and a higher voltage drop. Ultimately, a voltage collapse could occur, causing a system shut down. Controlling reactive power implies regulating the voltage, which is important for the proper operation of an electric system.

Depending on the intensity of the current flow, lines can absorb or produce reactive power. High current flow during daytime leads to high reactive power consumption as well as a voltage drop, and vice-versa. In these conditions, the distribution system becomes a reactive power consumer or producer depending on its operation point.

The task of the system operator is to define the volume of service for the participants in the energy market. In addition to this, the system operator must also define who will participate in the voltage control service, how the service is going to be provided and how is it regulated.

Traditionally voltage support is performed by capacitor banks, load-tap changing transformers and voltage regulators, see [**62**], the physical location of the microgrid, near the load, is of great importance and it could be possible for microgrids to provide local reactive power support. A microgrid or group of microgrids may act as an aggregated reactive power compensator providing voltage support to the transmission grid.

Similar to Active power support, voltage control scheme can be divided into three control levels, according to areas of action and deployment time. The three control levels are described in [**78**] as:

- Primary Voltage Control: It keeps the voltage within specified limits of the reference values. Its action occurs in a few seconds. Automatic Voltage Regulators are used to control voltage in primary control and their action takes effect in a few seconds;
- Secondary Voltage Control: It has the main goal of adjusting, and maintaining, voltage profiles within an area and of minimizing reactive power flows. Its action can take up to a few minutes. The control actions associated with secondary control include modifying reference values for Automatic Voltage Regulators, switching Static VAR Compensators and adjusting On-Line Tap Changing transformers.
- Tertiary Voltage Control: It has the goal of achieving an optimal voltage profile and of coordinating the secondary control in accordance with both technical and economic criteria. It typically uses an algorithm of OPF. The time-frame of this control action is around some tens of minutes. The control variables used are generator voltage references, reference bus voltages, and state of operation of reactive power compensators.

In the case of compensated procurement, the revenue can be calculated in the same way as for frequency support provision.

Some examples of reactive power compensation are presented in [**79**]. The New York Independent System Operator uses the capability compensation approach plus lost opportunity cost compensation. All generators and qualified non-generator resources are paid $3.92/kVAr per year for the voltage support service. Additionally, a generator receives an opportunity cost payment when the independent system operator forces the supplier to lower its real power output below its economic operating point.

The California Independent Service Operator requires generators to operate within a power factor range of 0.90 lagging (producing VArs) and 0.95 leading (absorbing VArs). It pays generators their opportunity cost when it forces them to dispatch reactive power outside this range.

In the United Kingdom, the price for reactive power support is determined through an auction. Generators include in their bids for voltage support a capacity component (£/VAr) and a utilization component (£/VArh). Afterward, the chosen generators enter an annual contract with the system operator independently. In March 2011 utilization compensation was at $0.0045/kVArh.

The researchers of [**78**] conclude that in order to provide the correct incentives for the spread of DG and MG, a market structure that is able to accommodate the services these units can provide should be developed. With the development of this new market structure, major institutional changes will have to take place and they remark some of them have already begun.

2.5.5 PEAK SHIFTING

In a microgrid, the BESS can function either as a load (during charging period) or as a generator (when discharging). Therefore, it is able to perform peak shifting function by reducing peaks and increasing valleys in the load profile. The principle of peak shifting is illustrated in Figure 20.

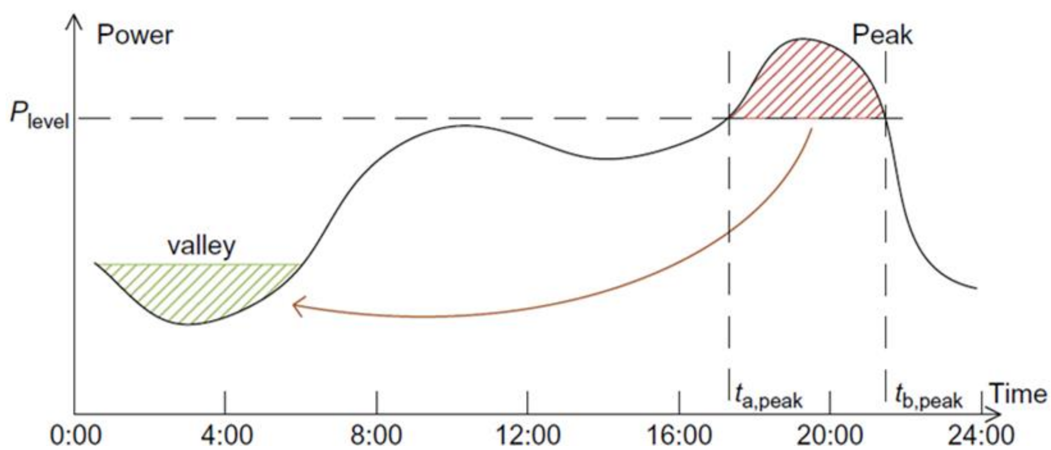

Figure 20: The principle of peak shifting. [**17**]

Load leveling and peak shifting are both tools that deal with the variation in demand. However, load leveling is more focused on short-term fluctuation, while peak shifting is more for the long-term (24 h) variation.

For a grid-connected MG, peak shifting can help reduce losses and the operation cost by reducing power requirements from the utility grid during peak time, thus postponing or omitting investments on network reinforcement.

The value of upgrade deferral is highly dependent on local grid topology and utility structure. To value this service, a list of planned network upgrades that might be deferred by the presence of the MG needs to be determined. For this, the network upgrade timeline needs to be determined both with and without peak reduction from the MG. A method to estimate Investment deferral value is discussed in Annex II.

2.5.6 RELIABILITY

Historically one of the main drivers for customers to install MG has been reliability improvement, especially for those customers who carry out sensitive activities with high interruption costs (banks, hospitals, etc.). A MG installed for this purpose operates primarily in standby as backup power ready to operate in islanded mode in case of emergencies or utility supply interruptions.

Consumer reliability is typically evaluated in terms of system and customer average interruption frequency and/or duration, such as SAIFI (System Average Interruption Frequency Index), SAIDI (System Average Interruption Duration Index), CAIFI (Customer Average Interruption Frequency Index), and CAIDI (Customer Average Interruption Duration Index). These indices are widely used to evaluate power quality in power systems. When a MG is deployed, these metrics can be significantly improved.

The impact of a MG on reliability can be measured using any of the previously mentioned indices, comparing the previous situation and the new operation with a MG.

Improved reliability can be translated into economic benefits for consumers and utility due to a reduction in interruptions costs and non supplied energy (NSE). The magnitude of these benefits is dependent upon load criticality, the value of lost load, and the availability of other alternatives such as backup generation or automatic load transfer trips. Typical SAIFIs are on the order of 1-2 outages per year and SAIDIs are on the order of two hours per year in the United States [**72**].

2.5.7 LOAD LEVELING

Energy demand is ever increasing and may lead to blackouts, failures, and high energy prices. If loads in a network are growing, the growth will increase the strain on various network components. If an operating limit is reached, some infrastructure investment is needed to mitigate this. The work presented in [**80**] points out that today, these reinforcements are difficult to implement mainly because of environmental constraints.

Load leveling is useful to reduce the influence of the load variation. The principle of load leveling is shown in Figure 21. The original load is changing constantly due to the switching on and off of the devices in the system. With the help of the ESS, the sudden increase and decrease of load can be compensated for, which means that the ESS works like a floating load. The resulting load curve can keep constant for a duration if the mean value of the load does not change too much.

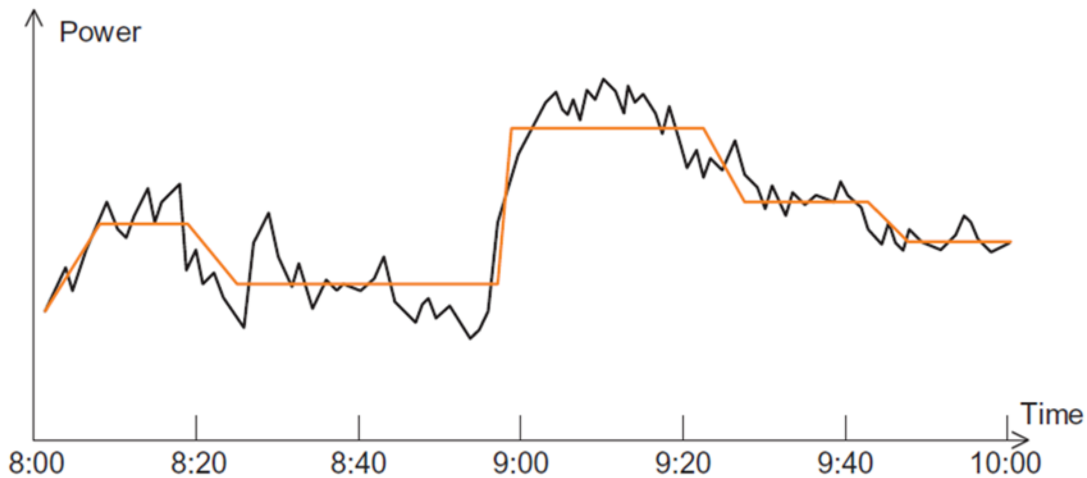

Figure 21: The principle of load leveling. [**17**]

The T&D system has to sized for these short time periods micro-peaks. This extra cost in keeping up with the peak demand is passed to the customers in the form of demand charges. The authors of [**80**] estimate these charges can make up as much as one-half of a facility's electricity bill. In research [**81**], the authors found deferral benefit values of up to $1200 USD per kW of operating DG.

2.5.8 Loss reduction

The ability of DG to reduce distribution network losses has been widely recognized by the industry. If a MG injects power locally without exceeding the local demand, the currents in that feeder will be reduced and the losses will be reduced even further, due to the quadratic dependence of losses on the magnitude of electrical current. Reducing the current to half will reduce the losses by a factor of four.

The authors of [**81**] propose a method to estimate this effect. This method is used and estimates that an optimal location of DG can reach up to 2.5% of their power in total network loss reduction.

However, this value changes widely according to the operation point and the distribution network parameters. This work also shows a loss reduction factor of 2% for different operating hours, which may represent important economic benefits to the utility during peak load periods, ranging between 0.25 ¢/kWh to 0.84 ¢/kWh for the specific load reduction factor (2%).

2.5.9 INVESTMENT DEFERRAL

Distribution utilities have traditionally followed the load growth within their concession areas through the investment on new power transformers in heavy loaded substations or by the upgrade or installation of new distribution feeders. However, in many cases, the costs of upgrading the network by traditional procedures can reach extremely high costs, especially in congested metropolitan areas.

Because MG embeds new generation within the existing radial distribution system, system upgrades that would otherwise be necessary to meet growing load can be postponed or entirely avoided. The authors of [**82**] and [**83**] studied the benefits that DG and MG can provide by deferring investment.

When a MG is operated near the loads, the currents in some of the feeders of those loads are reduced, according to its power and location in the network, especially on the extremities of it. As time passes and the demand across the network continues to grow, the feeder currents reach the initial values found before the MG started to operate. The benefit to the distribution utility is clear: it will take more time for the current on those loaded transformers or feeders to reach the technical limits at which new investments have to be put in place. The value of the deferral of these investments depends on the investment costs and the time by which these investments are deferred. In order to quantify the investment deferral benefit, the corresponding costs over a given planning horizon without MG are to be compared to those investments required in a scenario with MG. A simple model to calculate this cost is presented on Annex III.

Some utilities have recognized the opportunity of utilizing DG solutions to defer the investment on distribution wires and power transformers. The authors of [**84**] identified that in some cases, DG has even been the only viable solution found to supply growing demands in certain neighborhoods, due to “not in my backyard” opposition and aesthetical concerns.

2.5.10 BLACK START

Normally, the electric power used within a power plant is provided from the station's own generators. If all of the power plant's main generators are shut down, station service power is provided by drawing power from the grid through the plant's transmission line. However, during a wide-area outage, off-site power from the grid is not available.

Black Start (BS) is the procedure to recover from a total or partial shutdown of the transmission system which has caused an extensive loss of supplies. The authors of [**85**] identify two approaches for the entire power system restoration procedure: The first one is the conventional top down, starting from large plant restart and transmission energization. This entails isolated power stations being started individually and gradually being reconnected to each other in order to form an interconnected system again; the second one is bottom-up, starting from the distribution side, exploiting DG units and microgeneration capabilities. Synchronization among these areas follows afterward. This approach helps to reduce restoration times and to reduce the unserved electric energy during major failures.

The likelihood of a total or partial system shut-down occurring is considered remote. In the unlikely event of a BS, this service requires the provider to follow a sequence of actions aiming to energize, restore and stabilize the system to its pre-blackout condition. Under emergency conditions, BS stations/units receive electrical supply from a small auxiliary generating plant located on-site (BS Auxiliary Unit) instead of the grid.

Not all power stations have, or are required to have, this BS capability. BS capability needs to be a consideration when the plant is being built. Most DG can’t provide BS capability on its own, wind turbines, mini-hydro, or micro-hydro plants are often connected to induction generators which are incapable of providing power to re-energize the network. The different requirements for a black start unit for many countries are presented in Annex IV.

A MG can operate in islanded mode and can potentially provide valuable energy and ancillary services to the grid. The success of a MG restoration procedure requires the availability of some microsource with BS capability, which involves an autonomous local power supply to feed local auxiliary control systems and to launch generation. MGs with generation such as microturbines, ESS, and fuel cells have a fast ramping source, with the capability to ramp from 0 to full load in less than 30 seconds. A Full list of the required attributes and MG performance for BS is presented on Annex V.

The authors of [**86**] propose the following sequence for a MG BS: The main problems to deal with during the restoration procedure include building the LV network, connecting microgenerators, controlling voltage, controlling the frequency and connecting controllable loads. Considering these problems the following sequence of actions for MG restoration should be carried out:

1. **Disconnection of all loads** in order to avoid large frequency and voltage deviations when energizing the network. The MG should also be sectionalized around each Microsource (MS) with standalone restart capabilities in order to allow it to feed its own (protected) loads. These actions lead to the creation of small islands inside the MG to be synchronized later.
2. **Building the LV network**. The MGCC decides which MS energizes the LV cables and the distribution transformer based on information about rated powers, load percentage or other market conditions.
3. **Small islands synchronization.** MS already in operation in standalone mode should be synchronized with the LV network. The synchronization conditions (phase sequence, frequency, and voltage differences) should be verified by local MC in order to avoid large transient currents and power exchanges. If there are controllable MS without BS capability, they can then also be synchronized with the LV to supply their local controls and prepare to launch generation.
4. **Connection of controllable loads** to the LV network is performed if the MS running in the LV network are not at fully loaded. The amount of power to be connected should take into account the available storage capacity in order to avoid large frequency and voltage deviations during load connection.
5. **Connection of non-controllable MS**, like photovoltaic and wind generators. At this stage the system has MS and loads capable of smoothing voltage and frequency variations due to power fluctuations in non-controllable MS, so they can now be connected.
6. **Load increase**. In order to feed as much load as possible, depending on production capability, other non-controllable loads can then be connected.
7. **MG synchronization with the MV** network when it becomes available.

The UK study [**87**] estimates that the deployment of smart grid and communications technology developments, in combination with storage facilities and (distributed) wind and solar units, might be sufficiently developed by 2025 to be used for BS services or restoration strategies. Combinations of the different technologies may not require large additional expenditure because of the natural developments.

As indicated in [**72**], in cases of voltage or frequency excursions, the MG can island instead of providing BS services. The criteria for islanding will, therefore, have to be balanced with the requirement to provide support services.

2.5.10.1 Black start remuneration

Electricity transmission networks around the world vary according to local factors including: generation mix, geographical size, size of demand, geographical distribution of demand and generation, acceptable time to restoration, level, availability, and resilience of external interconnections with other TSO and regulatory framework [**88**]. All of these factors influence the restoration plans of the local TSO, the associated black start requirements and remuneration.

The authors of [**87**] indicate that generally BS providers are paid an agreed fee per settlement period for their availability and a utilization payment for testing purposes. The payments will depend on a number of factors including what plant has been instructed, whether the plant is registered as Balancing Unit and what type of fuel was used.

In the United Kingdom, the grid operator has commercial agreements in place with some generators to provide black start capacity, recognizing that black start facilities are often not economic in normal grid operation [**89**].

In North American, the procurement of black start varies with each independent system operators. Traditionally, black start was provided by integrated utilities and the costs were rolled into a broad tariff for cost recovery from ratepayers. In the more recent deregulated environment, this legacy of cost-based provision has persisted, and even recent overhauls of black-start procurement practices have not necessarily shifted to competitive procurement. The most commonly used methods of procuring BS in the USA are three:

1. The first method, **cost-of-service**, is the most common and simplest. The exact mechanisms differ somewhat between providers, but the same approach is used, namely that units are identified for BS and their documented costs are then funded and rolled into a tariff for cost recovery.
2. The second method is a **flat rate payment** which increases BS remuneration to encourage provision. The monthly compensation paid to a generator is determined by multiplying a flat rate (in $/KWyr) by the unit's Monthly Claimed Capability for that month.

3. The third method is **competitive procurement**. Under this approach, a market for black start services is run. The interested participants submit an hourly standby cost in $/hr (e.g. $70 per hour), often termed an availability bid, that is unrelated to the capacity of the unit. Using various criteria ERCOT evaluates these bids and the selected units are paid as bid, presuming an 85% availability.

2.6 DISCUSSION

This chapter reviewed various concepts and mathematical tools necessary for this thesis in order to achieve the objectives presented in chapter 1: The state of the art of DER units and BESS, the concept of a microgrid, including its control and dispatch. Finally the provision of auxiliary services by the MG, its remuneration and limitations were presented.

Considering the state of the art presented in section 2.1, 2.2 and 2.3, we observed that most MG include a BESS, due to the unique requirements of the MG, with a high requirement for capacity, daily usage and fast response time. As indicated in section 2.2.2, BESS are afflicted by limitations that reduce their efficiency or expected lifetime. The six phenomena presented in section 2.2 will be modeled in chapter 3 to correctly evaluate the BESS performance and expected lifetime.

From all the UC solving methods presented in section 2.4, the proposed EMS will be implemented using MILP. This technique allows the modeling of different MG's units through the combined use of linear equations and integer variables.

As seen in section 2.5, multiple authors have studied and presented models for different ancillary services that MG can provide, but most of them focus on studying a single service, and a few of them study the effect of MG with the ability to provide multiple services, leaving the decision of which services a MG should provide as an unsolved problem.

This thesis addresses this problem, combining most of the services presented in section 2.5 in a single MILP dispatch problem to be solved in real time. This allows the optimization tool to choose which services to offer. To ensure the MG can effectively provide the offered services, specifically to ensure reliability during unplanned outages or reduction on available importable power, a robust approach with multiple scenarios will be explored via Bender's cuts, as discussed in section 2.4.1.

Of all the services that a MG can provide presented in section 2.5, we will focus on the following ones: energy arbitrage, demand response, emission reduction, spinning reserve (active power reserve), peak shaving, reliability and capacity bidding. These services were chosen due to their direct impact on the scheduled operation.

3 ROBUST EMS FORMULATION

The emphasis of this thesis is the energy management of a MG, either grid-connected or islanded, capable of offering services to the grid while connected and ensuring reliability in case of an outage via a master-slave iterative optimization.

By piecewise linearization of non-linear elements, such as the battery degradation and variable discharge efficiency, the energy management problem is formulated as a MILP.

Depending on the desired operation, the EMS can be used to maximize revenues, minimize cost or ensure the provision of energy to its loads over a given time horizon, among other options. This is achieved by finding the optimal control sequence of the controllable units, taking into account market prices, forecasting power of non-dispatchable DG units, load level and the required capacity for unplanned islanding. In this thesis, the work will be focused on the combined effect of minimization of operational cost and maximization of revenues provided by services.

3.1 GENERAL UC MODEL

As explained in section 2.3, MG can be defined as a cluster of loads and DER units that are operated in coordination and perceived as a single element by the main grid. It can consist of storage units, fossil fuel units, renewable generation, controllable loads and uncontrollable loads. The general problem can be divided into general equations and general constrains.

3.1.1 GENERAL EQUATIONS:

The objective of microgrids is to provide energy to its load while minimizing cost or maximizing revenues according to unit operating costs and market prices. The general equation that minimizes the operational cost of a MG can be described as:

$$\min J = \sum_{i=1}^{N}\sum_{t=1}^{T} FC_{i,t} + MC_{i,t} + SU_{i,t} + \Delta SoH_{i,t} + UE_t + GB_t - GS_t - AS_t \quad (1)$$

where $FC_{i,t}$ is the fuel cost of the generating unit i in period t, $MC_{i,t}$ is the maintenance cost of the generation unit i on period t, $SU_{i,t}$ is the startup cost for unit i on period t, $\Delta SoH_{i,t}$ refers to the reduction of health in the ESS i on period t, UE_t refers to the penalty imposed by having unserved energy. While the MG is connected to the main grid, it has the option to buy energy (GB_t) and sell energy (GS_t) from the main grid. Finally, AS_t represents the different auxiliary services the MG can provide to the main grid. These services will be further discussed on section 3.5.

$FC_{i,t}$ and can be modeled as a piece-wise linear equation with V pieces, described as

$$FC_{v,i,t} = \sum_{v}^{V} \left(da_{v,i,t} \cdot PF_{v,i,t} + db_{v,i,t} \cdot BF_{v,i,t} \right) \quad (2)$$

$PF_{v,i,t}$ is the power for piece v, $da_{v,i,t}$ is the efficiency of piece v, $BF_{v,i,t}$ is the binary that indicates which v piece for generator i on period t is in effect and $db_{v,i,t}$ is the constant load consumption for piece v. Thus the power of each fuel based generation unit is described as

$$PF_{i,t} = \sum_{v}^{V} PF_{v,i,t} \quad (3)$$

$MC_{i,t}$ is the maintenance cost of the generation unit i on period t and is described as

$$MC_{i,t} = BM_i + mc_i \cdot PF_{i,t} \quad (4)$$

where BM_i is the base maintenance cost per period, independent of the unit use, while mc_i is the incremental maintenance cost of unit i.

$SU_{i,t}$ is the startup cost for unit i on period t, modeled as

$$SU_{i,t} \geq [\mathrm{B}_{i,t} - \mathrm{B}_{i,t-1}] \cdot \mathrm{CPstart}_{i,t} \quad (5)$$

where $\mathrm{B}_{i,t}$ is the binary that represents the on/off status of the generator i on period t and $\mathrm{CPstart}_{i,t}$ is the cost associated with starting up the generator i on period t.

The term $\Delta SoH_{i,t}$ can be described as

$$\Delta SoH_{i,t} = Cbess_i \cdot \left(\Delta LoLcic_{i,t} + \Delta LoLcal_{i,t} \right) \quad (6)$$

where $Cbess_i$ is the reinvestment cost of BESS i, $\Delta LoLcic_{i,t}$ refers to the loss of life caused by cycling the BESS i on period t and $\Delta LoLcal_{i,t}$ is the loss of life independent of the use. These terms will be further expanded in section 3.4.

The term UE_t refers to the penalty imposed by having unserved energy. Depending on the importance of the unserved load, the penalty cost for each load i, $UE_{i,t}$, may be different. This term can be described as

$$UE_t = \sum_{i}^{n_L} UEP_i \cdot UE_{i,t} \quad (7)$$

where the unserved energy penalty, UEP_i, represent the penalty value for each kWh not provided to load i and $UE_{i,t}$ is the amount of energy not served to load i on period t.

3.1.2 General Constraints:

The previous equations must comply with the following constraints.

3.1.2.1 Power balance

For each period, the generated power must be equal to the consumed power, described as

$$\sum_{t}^{T}\left(PD_{i,t} + PND_{i,t} + PS_{i,t} - PS_t + Pimp_t - Pexp_t\right) = \sum_{t}^{T}\left(NL_{i,t} + CL_{i,t} + UE_{i,t}\right) \quad (8)$$

where $PD_{i,t}$ is the power of dispatchable generation units, $PND_{i,t}$the power of non dispatchable generation units, $PS_{i,t}$the power of the storage system (which can be positive or negative), $Pimp_t$ is the power imported (or bought) from the grid and $Pexp_t$ is the power exported (or sold) to the grid, $NL_{i,t}$ are non-controllabe loads, $CL_{i,t}$ are controllable loads and $UE_{i,t}$ is unserved energy.

3.1.2.2 Dispatchable unit power limit

The power limit of each dispatchable unit is represented by

$$B_{i,t} \cdot PDmin_i \leq PD_{i,t} \leq B_{i,t} \cdot PDmax_i \quad (9)$$

Where $B_{i,t}$ is the binary that represents if the generating unit i is on or off and has a value of 0 in case the unit is not operational at time t and 1 if it is operational, $PDmin_i$ is the minimum power and $PDmax_i$ is the maximum power unit i can have while in operation.

3.1.2.3 ESS energy balance

The balance of energy on any ESS through time is represented as

$$Eb_{t,i} = Eb_{t-1,i} - \eta d_i \cdot Pb_{t,i}^{+} + \eta c_i \cdot Pb_{t,i}^{-} \qquad t \in (2,T) \quad (10)$$

And for the first time step (t=1)

$$Eb_{t,i} = Eb0_i - \eta d_i \cdot Pb_{t,i}^{+} + \eta c_i \cdot Pb_{t,i}^{-} \qquad t = 1 \quad (11)$$

In these equations the term $Eb_{t,i}$ is the energy on the BESS i on period t, $Pb_{t,i}^{+}$ is the energy that the battery provides to the MG while $Pb_{t,i}^{-}$ is the energy the ESS absorbs from the MG. ηd_i is the discharge efficiency and ηc_i is the charge efficiency of the ESS. $Eb0_i$ is the energy of BESS i at the start of the simulation.

3.1.2.4 ESS energy limit

The energy limit of the ESS follows equation 11.

$$Ebmin_i \geq Eb_{t,i} \geq Ebmax_i \qquad (12)$$

Where $Ebmin_i$ is the minimum energy and $Ebmax_i$ is the maximum energy BESS i can have at any given time.

3.1.2.5 Demand Response

If DR is considered, the balance equation change as follows

$$\sum_{t}^{T}\left(Pg_{i,t} + PND_{i,t} + PS_{i,t} - PS_t\right) = \sum_{t}^{T}\left(NL_{i,t} + \overline{CL_{i,t}} + UE_{i,t}\right) \quad (13)$$

where $\overline{CL_{l,t}}$ are the modified controllable loads, which must obey the following restrictions

$$CL_{i,t} \cdot DRmin_{l,t} \leq \overline{CL_{l,t}} \leq CL_{i,t} \cdot DRmax_{l,t} \quad (14)$$

where $DRmax_{l,t}$ and $DRmin_{l,t}$ are the maximum and minimum ranges that the original load l can be shifted on period t. Additionally, to ensure the load is shifted during the day and not changed and additional constrain is added.

$$\sum_{t}^{T}(CL_{i,t}) = \sum_{t}^{T}(\overline{CL_{l,t}}) \quad (15)$$

3.2 CONNECTED MODE

While the MG is connected to the EPS, there are some additional constrains that are activated.

3.2.1 CONNECTED MODE CONSTRAINTS:

3.2.1.1 Grid Power limit

Considering possible limits of the Grid, power exchanged between the Grid and the MG is limited by

$$Pexp \leq (Pimp_t - Pexp_t) \leq Pimp \quad (16)$$

where $Pexp$ the maximum power the Grid can accept from the MG and $Pimp$ is the maximum power the grid can provide to the MG.

3.3 ISLANDED MODE

In islanded mode, the MG is separated from the upstream distribution grid and must aim to keep supply to its loads using the available DER units and shedding load as needed with minimum operating cost. The operation is more limited in this case, as there is no fallback in case of an increase in load or reduction in renewable generation.

3.3.1 ISLANDED MODE CONSTRAINTS:

3.3.1.1 Power reserve

When operating in islanded mode, a power reserve may be imposed at each time-step to the MG to compensate forecasting errors. The upper and lower power reserve coefficient values, R_u and R_l, depends on the forecasting accuracy of uncontrollable units power and load level and must leave adequate power margin of controllable units to deal with real-time power fluctuation owing to forecasting error.

$$\sum_{i}^{N}\left(BD_{i,t} \cdot PDmax_i - PD_{i,t}\right) \geq R_u \cdot \left(\sum_{i}^{N} NL_{i,t} + CL_{i,t} + PND_{i,t}\right) \quad (17)$$

$$R_l \cdot \left(\sum_{i}^{N} NL_{i,t} + CL_{i,t} + PND_{i,t}\right) \geq \sum_{i}^{N}\left(BD_{i,t} \cdot PD_{min\,i} - PD_{i,t}\right) \quad (18)$$

Where $PDmax_i$ is the maximum power of dispatchable unit i and the binary variable $BD_{i,t}$ represent the status of unit i and has a value of 0 in case the unit is not operational at time t and 1 if it is operational.

3.3.1.2 Grid Power limit

Considering the Grid is not accessible on islanded operation, the power exchanged between the Grid and the MG is limited by

$$0 \leq Pimp_t \leq 0 \quad (19)$$

$$0 \leq Pexp_t \leq 0 \quad (20)$$

3.4 BESS MODEL

BESS can be modeled with different degrees of detail depending on its technology and expected use. The authors of [**90**] identify that concerning the modeling of BESS, the vast majority of studies represents BESS by their energy and power capacity, and use a constant efficiency (roundtrip or dis/charge). There are many unique properties for batteries that are not considered, but for an optimal dispatch it is necessary to be able to predict the lifetime, efficiency and effective capacity correctly for a BESS in operation. A few exceptions use variable efficiency, for example as a function of their state of charge [**91**] or their state of charge and operating current [**92**].

The lifetime and efficiency of ESS are affected by cycling, consequently impacting their reinvestment and maintenance costs. The different ESS technologies exhibit large differences in how the BESS phenomena affect them. How to model the phenomena presented in 2.2.2 will be further discussed in this section.

3.4.1 CYCLICAL AGING

Based on the work of Bo Zhao et al [**93**], who's work uses piecewise linearization to emulate the effect that different DoD has on the effective Ah, the equation for effective Ah-throughput ($Ah_{eff_{b,t}}$) for battery b can be presented as:

$$Ah\_eff_b = \sum w_E Ah_E = \frac{\sum w_E P_E \Delta t}{U_b} = \frac{\lambda_{b,t}}{U_b} \quad (21)$$

where the BESS discharge power for event E is P_E and U_b is the average battery voltage. The weighted BESS power $\lambda_{b,t}$, which depends on the SoC of the battery, can be formulated as

$$\lambda_{b,t} = \sum w_E \cdot P_E \cdot \Delta t = \sum_{v=1}^{n_v} Pb_{b,t}^{+}(t) \cdot \lambda_{b,v} \cdot \Delta t \quad (22)$$

where n_v is the number of pieces, $\lambda_{b,v}$ is the weight for each of the n_{soc} pieces, based on manufacturers information. The graphical representation of this weight for a Lead-Acid BESS is shown on Figure 22.

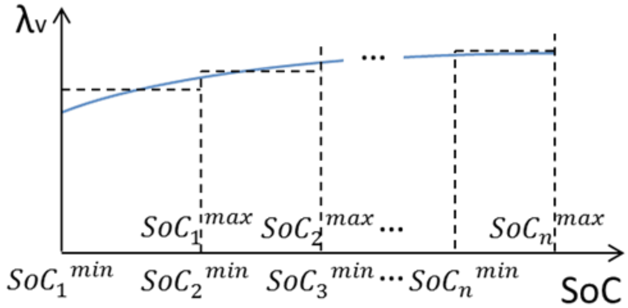

Figure 22: λ vs SOC for lead acid BESS.

To ensure no more than 1 piece is active in each period, the following restrictions are added.

$$\sum_{v=1}^{n_v} Bsoc_{b,v,t} \leq 1 \quad (24)$$

$$SOCmin_{b,v} \cdot Bsoc_{b,v,t} \ \leq SOC_{b,v,t} \leq SOCmax_{b,v} \cdot Bsoc_{B,v,t} \qquad v \in [1, n_{soc}] \quad (25)$$

where $Bsoc_{b,v,t}$ is the binary that indicates if the chosen piece v for BESS b on period t is in use or not and $SOCmin_{b,v}$ is the minimum SoC and $SOCmax_{b,v}$ is the maximum SoC for piece v and BESS b. Thus the battery power is constrained as

$$Pb_{b,t}^{+} = \sum_{v=1}^{n_v} Pb_{b,t,v}^{+} \quad (25)$$

$$0 < Pb_{b,t,v}^{+} < Bsoc_b \cdot M \quad (26)$$

Where $P_{b,t}^{+}$ is the BESS b discharge power and $P_{b,t,v}^{+}$ is the power for piece v. With ${Ah_{eff}}_{b,t}$ we can obtain the LoL based on operation ($LoLc_{b,t}$) as

$$LoLc_{b,t} = \frac{{Ah_{eff}}_{b,t}}{{Ah_{throughput}}_b} \ (27)$$

where ${Ah_{throughput}}_b$ is the total Ah capacity of the BESS b operating under nominal conditions. We can now define the SoH for each period as

$$SoH_{b,t} = SoH_{t-1} - LoLc_{b,t} \quad t = [2, \mathrm{T}] \quad (28)$$

$$SoH_{b,t} = SoH_0 - LoLc_{b,t} \qquad t = 1 \qquad (29)$$

The associated operational cost for the BESS can be formulated as

$$Cbess_b \cdot LoLc_{b,t} = Cbess_{b,t} \quad (30)$$

where $Cbess_b$ is the reinvestment cost of the BESS b and $Cbat_{b,t}$ is the cost of using the BESS b on period t.

3.4.2 CALENDAR AGING

Adapting the work of Yang et al [**18**], the calendar degradation ($LoLt_b$) is modeled as a minimum per interval degradation estimate, written as.

$$LoLt_b \geq \sum_{t}^{T} \left[\frac{\Delta t_t}{CL_b} - LoLc_{b,t}\right] \quad (31)$$

where T is the total number of optimization periods, Δt_t is the length of each period (in hours) and CL_b is the total Calendar Life of BESS b in hours. If the battery is not used at all ($LoLc_b = 0$), $LoLt_{b,t}$ will attain its maximum value.

3.4.3 PEUKERT'S LAW

To incorporate this phenomenon, we will use a similar approach to the previous work presented in 3.4.1 and use piecewise linearization.

$$\delta_{b,t} = \sum_{w=1}^{n_w} Bpeuk_{b,t,w} \cdot Pb_{b,t}^{-} \cdot \delta_{b,w} \quad (32)$$

where $\delta_{b,t}$ is the weighted power actually discharged from the battery, which may be different from the real useful power discharged from the battery ($P_{b,t}^{-}$). $Bpeuk_{b,t,w}$ is the binary that indicates if the piece w is in effect. The weight of the discharge current for each piece w is $\delta_{b,w}$ and increases with the discharge current (or power) as shown in Figure 23.

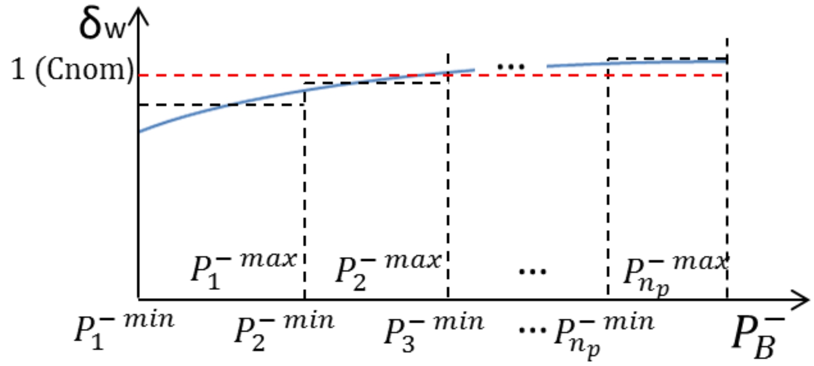

Figure 23: weight power (δ) vs power discharge.

To ensure only one piece is active at the same time, the following restrictions are included.

$$Pb_b^- = \sum_{w=1}^{N_w} Pb_{b,w}^- \quad (33)$$

$$Pbmin_{b,w} \cdot Bpeuk_{b,t,w} \quad \leq Pb_{b,w,t}^- \leq Pbmax_{b,w} \cdot Bpeuk_{b,t,w} \quad w = [1, N_P] \quad (34)$$

$$\sum_{w=1}^{N_w} Bpeuk_{w,t} \leq 1 \quad (35)$$

where $Pb_{b,w,t}^-$ is the real discharge power for each of the N_w pieces, $Pbmin_{b,w}$ and $Pbmax_{b,w}$ are the minimum and maximum powers for piece w.

Thus including the model of Loss of Life from (32) the energy balance equation for the battery, equation (10), can be expressed as

$$E_{b,t} = E_{b,t-1} + \eta c_b \cdot Pb_{b,t}^+ \cdot \Delta t_t + \delta_t \cdot \Delta t_t \quad (36)$$

3.4.4 Capacity Fading

Based on the work done by Guasch et al [**94**] on effective battery capacity reduction, the capacity of a BESS can be linked to its SoH by the equations

$$(0.2 \cdot SoH_b + 0.8) \cdot Eb\_min_b \leq Eb_t \quad (37)$$

$$Eb_t \leq (0.2 \cdot SoH_b + 0.8) \cdot Eb\_max_b \quad (38)$$

where SoH_b is the initial SoH of BESS b, Eb_min_b is the minimum and Eb_max_b is the maximum energy that can be stored on the BESS under optimal SoH.

3.4.5 SELF-DISCHARGE

Depending on the accumulated charge and the battery state of health, a self-discharging current must be considered. The authors of [**94**] evaluate the self-discharging (Psd_t) as

$$Psd_{b,t} = \eta sd_b \cdot E_{b,t} \cdot \frac{\Delta t_t}{24} \quad (39)$$

where $\eta sd_b$is the self-discharge coefficient, defined by the equation,

$$\eta_{sd} = a - b \cdot SoH \quad (40)$$

where a is the maximum daily self-discharge, typically at the end of the battery life, and b is the minimum daily self-discharge value, typically at the start of the battery life. As an example, Guasch considered a battery with a daily self-discharge between 0.1% and 1%, thus in that case the equation is

$$\eta_{sd} = 0.01 - 0.009 \cdot SoH \quad (41)$$

3.4.6 CHARGE AND DISCHARGE LIMITATIONS

Based on the work done by Palma et al [**47**], the minimum admissible power of the BESS, $Pmin_{b,t}$, can be approximated by n_s piecewise linear segments as

$$Pmin_{b,t} = \sum_s^{n_q} (\propto_{q,b} \cdot E_b^0 + \beta_{q,b} \cdot B_{b,q,t}) \qquad t = 1 \quad (42)$$

$$Pmin_{b,t} = \sum_s^{n_q} (\propto_{q,b} \cdot E_{b,t-1} + \beta_{q,b} \cdot B_{b,q,t}) \qquad t \in (2, T) \quad (43)$$

where E_s^0 is the initial BESS energy, $E_{b,t}$ is the battery energy on interval t, $B_{b,s,t}$ is the binary variables that indicates which segment s is active (1) or not (0). The constants $\propto_s$ and β_s are chosen to obtain the desired curve. Additionally, the energy is constrained as

$$\sum_{s=1}^{N_q} Emin_{b,s} \cdot B_{b,s,t} \leq E_s \leq \sum_{s=1}^{N_q} Emax_{b,s} \cdot B_{s,t} \quad (44)$$

where $Emax_{b,s}$ is the maximum and $Emin_{b,s}$ the minimum bound for the segment s. To ensure only one stage is in use, the following restriction is included.

$$\sum_{s=1}^{N_q} B_{s,t} \leq 1 \quad (45)$$

With all these equations, we can obtain a piecewise linear approximation for the charging limits as seen in Figure 24.

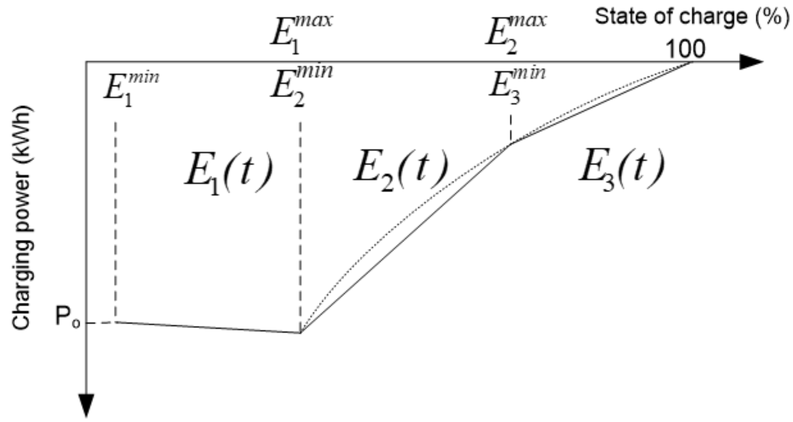

Figure 24: Minimum admissible power in the BESS vs. SOC [**47**]

The charge and discharge limitation of the BESS can be modeled by including the following restriction

$$P_{b,t}^{min} \leq P_{b,t} \leq P_{b,t}^{max} \quad (46)$$

3.5 SERVICES

To estimate the extent of the economic benefits that MG can obtain by offering different services to the Grid, generalized quantification models will be developed based on six of the services presented in section 2.5. The chosen services are those that can be implemented as part of an EMS and can be offered as a direct result of the MG operation. The selected services are:

- Energy arbitrage
- Demand response
- Emission reduction
- Spinning reserve (active power reserve)
- Peak shaving
- Reliability
- Capacity bidding

In order to develop these models and carry out the desired quantifications, some technical and economic assumptions have to be made and will be indicated on each service.

3.5.1 ENERGY ARBITRAGE

ESS has the capability of storing electricity during periods of low prices and releasing it for use during other periods when the use or cost is more beneficial, as explained in section 2.5.1.

To evaluate the economics of ESS for energy arbitrage, a commonly used model, like the one presented in [**95**], will be used.

$$AS_t^{EA} = Cexp_t \cdot Pexp_t - Cimp_t \cdot Pimp_t \quad (47)$$

where AS_t^{EA} is the net revenue of importing and exporting energy from the grid. $Cexp_t$ is the value of exporting energy to the grid and $Pexp_t$ is the amount of energy exported to the Grid, $Cimp_t$ is the cost of importing energy from the grid and $Pimp_t$ is the imported power on period t.

Typically $Cimp_t > Cexp_t$ due to distribution and transmission usage cost.

3.5.2 DEMAND RESPONSE

As presented in 2.5.2, coordinated loads are capable of modifying their consumption behaviors. Based on previous work presented in [**47**], this modification is modeled by shifting coefficients $S_{i,t}$ that are provided by the EMS. Therefore, the electric load is given by:

$$DRmin_l \leq CL_{l,t} \leq DRmax_l \quad (48)$$

where $DRmin_l$ is the minimum load shifting value and $DRmax_l$ is the maximum load shifting value for controllable load l. Additionally, it is assumed that the modified energy consumption can't be smaller than the expected demand for the whole optimization period. This constraint is given by:

$$\sum_{t=1}^{T} CL_{i,t} \geq \sum_{t=1}^{T} \widetilde{CL}_{i,t} \quad (49)$$

where $\widetilde{CL}_{i,t}$ is the originally expected electrical consumption on period t for controllable load i.

3.5.3 EMISSION REDUCTIONS

As explained in section 2.5.3, the reduction in carbon emissions can be compensated by carbon bonds or a similar mechanism. The revenue of this service will depend on the tons of CO2 not emitted, which depends on the marginal unit in each period. This auxiliary service can thus be formulated as:

$$AS_t^{ER} = C_{CO2} \cdot \eta\mathrm{er}_t \cdot Pexp_t \quad (50)$$

where C_{CO2} is the payment for each ton of CO2 and $\eta_{ER,t}$ is the number of tons of CO2 reduced by each displaced kWh. This amount will depend on the displaced generating unit, which using the methodology presented in [**96**] can be formulated as

$$\eta\mathrm{er}_t = \begin{cases} 0 & 0 \leq Cmg_t \leq A \\ \alpha_{ER} & A < Cmg_t \leq B \\ \beta_{ER} & B < Cmg_t \leq C \\ \gamma_{ER} & C < Cmg_t \leq D \end{cases} \quad (51)$$

where Cmg_t is the marginal cost of at the PCC. In this thesis α_{ER} will be the CO2 emissions of a coal based power plant, β_{ER} the CO2 emissions of a gas based power plant and γ_{ER} the CO2 of a diesel based power plant. It's important to note that this value is an online estimation and the real value has to be estimated with a posteriori analysis.

3.5.4 SPINNING RESERVE

Spinning reserve is necessary for the operation of a power system to balance instantaneous increases and reductions in load or generation, as explained in section 2.5.4.

For this work, it is assumed that these reserves are not actually used by the system, which the authors of [**33**] indicate as a valid assumption for primary reserve. The reason is that frequency deviation beyond the deadband is relatively rare (about 30% averaged over a day) and goes both ways. In reality, at least a certain percentage is used for frequency regulation whenever the frequency is out of the regulation deadband. The actual usage will depend on the whole interconnected system and varies from one system to another.

We will differentiate the reserve service for absorbing active power (down reserve) and injecting active power (up reserve) to the grid. Thus the equation that represents this service is:

$$AS_t^{SR} = -Cdw \cdot Rdw - Cup \cdot Rup \quad (52)$$

where AS_t^{SR} is the revenue perceived from the spinning reserve service Cdw is the cost per MW of down reserve , Rdw is the down reserve in MW, Cup is the cost per MW of up reserve and Rup is the up reserve in MW.

The MG has to ensure it has the available power to absorb or provide the promised power. To ensure the required power is available at all time, the following restrictions are included:

$$\left(PF_i^{max} \cdot BD_{i,t} - PF_{i,t}\right) + \left(PS_i^{max} - PS_{i,t}\right) + \left(CL_{l,t} - DRmin_l\right) \geq R_u \quad (53)$$

$$\left(PF_{i,t} - PF_i^{min} \cdot BD_{i,t}\right) + \left(PS_{i,t} - PS_i^{min}\right) + \left(DRmax_l - CL_{l,t}\right) \geq R_d \quad (54)$$

3.5.5 PEAK SHAVING

In many EPS, not only energy is paid, power is paid too. As presented in 2.5.5, this is especially important when the distribution grid is under pressure, such as in areas with congested lines or feeders. Power is typically paid based on the highest value of power on a certain month. This will be modeled as

$$AS^{PS} = -Ppeak \cdot Cpeak \cdot \sum_t^T \frac{\Delta t_t}{720} \quad (55)$$

$$P_{Peak} \geq Pimp_t \qquad t \, \epsilon \, (1, T) \quad (56)$$

where $Ppeak$ is the maximum imported power from the grid and $Cpeak$ is the cost per kW of peak power. AS^{PS} is presented as a negative value, since it has to be paid to the TSO.

3.5.6 RELIABILITY

As presented in 2.5.6, MG operating in grid-connected mode must also consider the possibility of a problem in the grid that forces unplanned islanding to ensure the continuous provision of energy to its loads. However, sufficient capacity needs to be available in a case the microgrid is required to switch to the islanded mode.

The MG must be able to switch to islanded mode at any given time in response to disturbances in the main grid. The MG would be resynchronized with the main grid once the disturbance is removed. The EMS, however, is not aware of when a disturbance will happen and its duration. Therefore, microgrid resources are to be scheduled in a way that local loads are supplied with no interruption using only local resources, i.e., an islanded operation, for an unknown time extent.

A similar problem was presented by Shahidehpour & Fu in [**60**]. In their work, they solve a Security-Constrained Unit Commitment (SCUC) for the main grid using Bender's decomposition. By dividing the problem into a UC master problem and check feasibility with the slaves, the SCUC is achieved. In the case of MG, a method to solve this problem has already been studied by the authors of [**97**], where they decompose the MG dispatch problem into a grid-connected operation master problem and several islanded operation subproblem. The microgrid capability in operating in the islanded mode for multiple hours is scrutinized by a T- $\boldsymbol{\tau}$ islanding criterion, starting on period T and with duration τ. The scheduling decisions determined in the master problem will be examined against the microgrid islanding feasibility in the islanded subproblem. The solution is examined for islanding to ensure the microgrid has sufficient online capacity for quickly switching to the islanded mode if required.

Figure 25 depicts the flowchart of the proposed MG optimal scheduling model. The problem is decomposed into a grid-connected operation master problem and an islanded operation subproblem. The master problem determines the optimal commitment and dispatch of available dispatchable units, charging and discharging schedules of energy storage systems, schedule of adjustable loads, and the power transfer with the main grid. The optimal schedule is used in the subproblem to examine the microgrid generation adequacy and confirm an uninterrupted supply of loads for a variety of islanding scenarios. If the islanding is not feasible, i.e., microgrid does not have sufficient online capacity to supply the local load, a Bender's cut is generated based on the unit commitments and energy storage system schedules and sent back to the master problem for recalculating the current solution. The cut indicates that the power mismatches in the subproblem can be mitigated by readjusting the units commitment in the master problem. The revised solution will be examined in the next iteration of the subproblem for islanding. The iterative process continues until all islanding scenarios have an acceptable unserved energy level or the maximum number of iterations is reached. The iterative model significantly reduces the problem computation burdens and enables a quick solution.

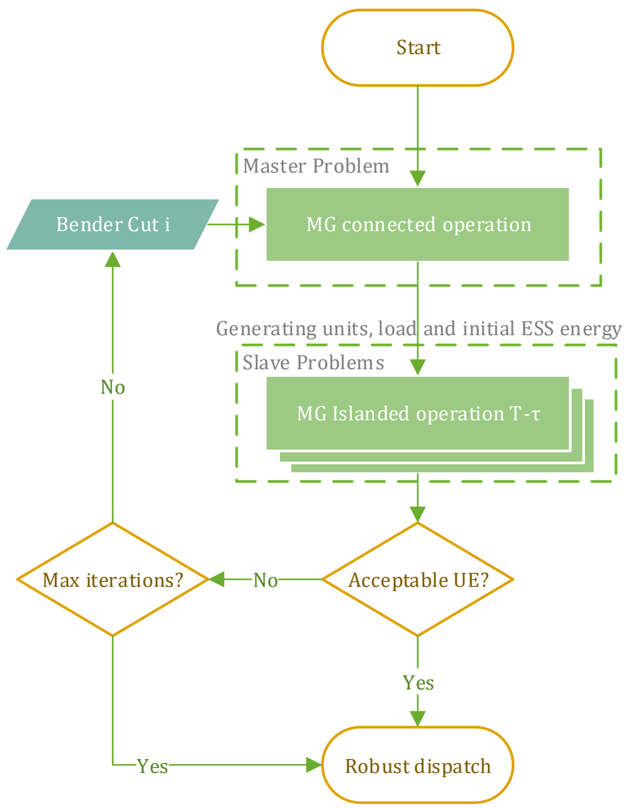

Figure 25: Robust dispatch for unplanned islanding flowchart.

Thus a Bender's cut will be added to the objective function. The balance equation for the slave problem will look like:

$$\sum_{t}^{n_E}(PF_{i,t} + PND_{i,t} + PS_{i,t}) = \sum_{t}^{n_E}(NL_{i,t} + CL_{i,t} + UE_{i,t} + R_{bs}) \quad (57)$$

The objective function of the slave will be expressed as:

$$\min J^* = \sum_{t=1}^{T}\left(\sum_{i=1}^{n_d} FC_{i,t} + \sum_{i=1}^{n_L} UE_t\right)$$

And the resulting Bender's cut can be formulated as:

$$Z_k = dE_k \cdot \left(Eb0_b - Eb\_slv_{b,k}\right) + FOslv_k \quad (58)$$

$$FOslv_k = \sum_{i=1}^{n_L} UE_{i,k} \cdot Cue_i \quad (59)$$

$$Z_R \geq \sum_{k=0}^{n_s} a_1 \cdot Z_{k+1} + a_2 \cdot Z_{k+2} + \cdots + a_l \cdot Z_{k+l} \quad (60)$$

Where Z_k is the Bender's cut for slave k, dE_k is the is the marginal cost of an increase/decrease in unserved energy for slave k, $Eb0_b$ is the stored energy on the battery b obtained from the master problem, $Eb_slv_{b,k}$is the is the initial state of slave k, $FOslv_k$ is the penalty for unserved energy on slave k, Cue_i is the penalty cost of load i, n_L is the # of loads, Z_R is the Bender's cut added to the objective function of the master problem, a_1 to a_l is the probability vector of a disconnection of different durations, from τ_1 to τ_l, and n_T are all the possible periods where an intempestive disconnection can happen. And thus the new master OF will be:

$$\min J = \sum_{i=1}^{N}\sum_{t=1}^{T} FC_{i,t} + MC_{i,t} + SU_{i,t} + \Delta SoH_{i,t} + UE_t + GB_t - GS_t - AS_t + Z_R \quad (61)$$

3.5.7 CAPACITY BIDDING

In some places, the ISO requires CB to prevent or alleviate peak hour congestions. A MG can reduce the load the grid observes by rearranging its consumption during the day, using its BESS, controllable loads or a dispatchable generator unit. The application of this service can be announced day ahead or on the same day. For this thesis, we will assume the latter situation. This service can be expressed as

$$AS^{CB} = Pcb \cdot C_{CB} \quad (62)$$

where C_{bs} is the payment provided to the MG for each kW of CB and Pcb is the power reduction offered for this service.

An important difference with spinning reserve is that for CB the reserve should ensure an operation time with reduced imported power for a predefined number of hours. This limitation will be formulated similarly to the Resilience problem in section 3.5.6, using slaves that simulate reductions in load at different times and of different durations, using the same restrictions as the original problem with one additional restriction for the required periods of capacity bidding:

$$Pimp\_slv_{k,t} \leq Pimp\_ms_t - Pcb \quad (63)$$

where $Pimp\_slv_{k,t}$ is the imported power from the grid for slave k on period t and $Pimp\_ms$ is the imported power on the original master problem. This ensures the CB requirements are achieved. The resulting Bender's cut can be formulated as:

$$Z_k = dCB_{b,k} \cdot (Pcb\_slv\_0 - Pcb\_slv_k) + (\Delta FO\_slv_k) \quad (64)$$

$$FOslv_k = \sum_{k=1}^{T} UE_{i,k} \cdot Cue_i \quad (65)$$

$$Z_{CB} \geq \sum_{k=1}^{T} a_1 \cdot Z_{k+1} + a_2 \cdot Z_{k+2} + \cdots + a_l \cdot Z_{k+l} \quad (66)$$

where Z_k is the Bender's cut of slave k, $dCB_{b,k}$ is the marginal cost of an increase/decrease in unserved energy, Pcb_slv_0 is the CB obtained from the master problem, Pcb_slv_k is the offered capacity bidding, ΔFO_slv_k is the increased cost of providing CB in slave k, $FOslv_k$ is the penalty for unserved energy on slave k, Cue_i is the penalty cost of load i, Z_{CB} is the Bender's cut added to the objective function of the master problem, a_1 to a_l is the probability vector of a CB event of different duration to happen, and n_T are all the possible events in which a CB event can be required. Thus the new master OF will be:

$$\min J = \sum_{i=1}^{N} \sum_{t=1}^{T} FC_{i,t} + MC_{i,t} + SU_{i,t} + \Delta SoH_{i,t} + UE_t + GB_t - GS_t - AS_t + Z_{CB} \quad (67)$$

4 CASE STUDY

The proposed model is applied to solve the dispatch problem for 3 MGs under different scenarios. Each case study examines the impact of operating a MG under different operating conditions and/or with the possibility to offer different services.

The first case study corresponds to an isolated MG in the village of Huatacondo, located in the north of Chile. Here six scenarios will be used to explore the operation of an islanded MG and some elements of the battery model.

In the second case study the operation of the benchmark connected MG proposed by CIGRE will be simulated. This MG is based upon a European medium-voltage distribution network benchmark and used in [**98**] & [**99**], connected to the main grid in Ontario, Canada. Using six different scenarios we will compare two different BESS technologies and explore operation when a connected MG can offer AS.

The third case study will simulate the Santa Rita Jail MG, located in California, USA. This Jail implemented a large PV plant and additional equipment to reduce its own consumption and increase its reliability. Using seven scenarios we will explore the AS this MG can offer to the grid and measures to keep the MG reliability.

For convenience and simplicity, some assumptions are made as follows:

- The controllable distributed generations and energy storage devices are allowed to participate in the energy market and ancillary service market simultaneously.
- The output power of controllable distributed generations is set to be constant in one operation period, not considering the intermittence or instantaneous power volatility of such energy sources.

4.1 CASE STUDY: HUATACONDO VILLAGE

The first case study will be based on the isolated village of Huatacondo (20° 55' 36'' S, 69° 3' 9'' W), in the Atacama Desert. Originally, its existing electric network, isolated from the EPS system, and was supplied only 4 hours a day by a diesel generator. On 2010 the ESUSCON microgrid was implemented, taking advantage of the renewable resources in the area, providing now 24-hour electricity service.

4.1.1 MICROGRID TOPOLOGY

The 5-bus system single-line diagram of Huatacondo, at rated voltage of 0.22 kV, is shown in Figure 26. The MG has a radial topology and operates disconnected from any other grid.

The generation resources are confined to three types of DER: diesel generators, photovoltaic panels, and a LA BESS connected to the MG through a bidirectional inverter. The unit parameters (maximum power and storage capacity for the DER) are presented in Table 3.

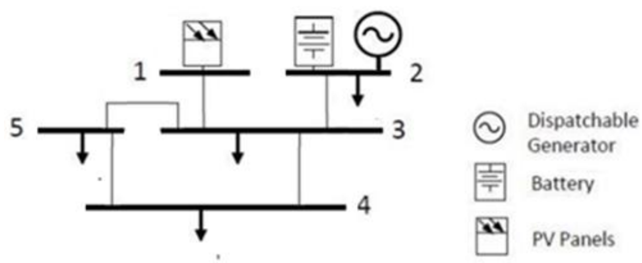

Figure 26: Microgrid topology of the Huatacondo MG

Table 3: Summary table of the Huatacondo MG

DER		Units
Genset	100	[kW]
PV	21	[kW]
Bess	30	[kW]
	100	[kWh]

Additionally, a demand-side option to compensate the generation fluctuations due to the renewable sources was tested but not yet implemented.

4.1.2 LOAD PROFILE

Based on operational data from the year 2017, the 24-hour aggregated load profile of Huatacondo Village is shown in Figure 27, with a peak demand of 12.7 [kW] at hour 21 and an average consumption of 9.1 [kW].

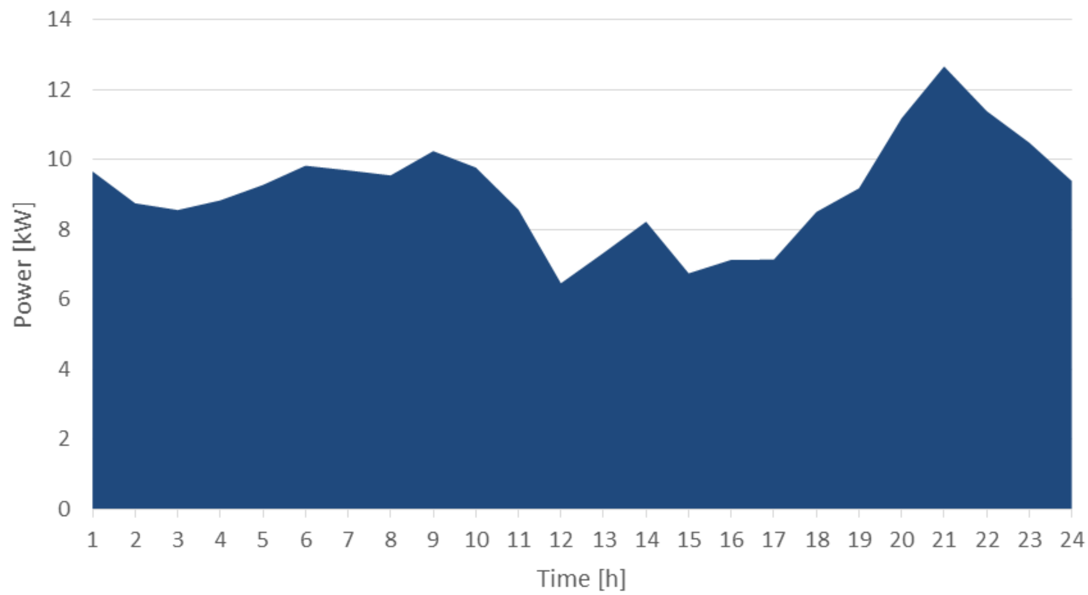

Figure 27: Load Profile for Huatacondo MG.

4.1.3 RENEWABLE RESOURCES

The photovoltaic generation of Huatacondo for the first simulation is presented in Figure 28, with an average generation of 5.9 [kW] and a 17.1 [kW] peak-generation at the 13 hour.

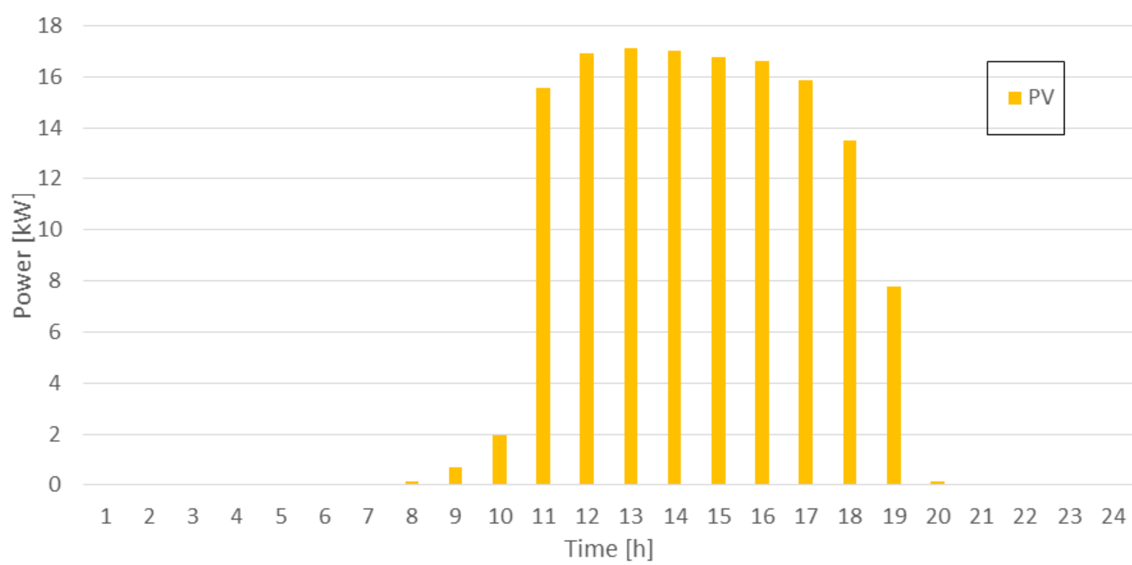

Figure 28: Renewable generation for Huatacondo MG.

4.1.4 UNIT PARAMETERS

The diesel generator operating cost parameters are obtained assuming a diesel price of 1 [USD/l]. The diesel generator maximum & minimum power, the variable (alpha) and static (beta) consumption and the startup cost of the generator are presented in Table 4.

Table 4: Genset parameters for Huatacondo.

Unit #	Pmax [kW]	Pmin [kW]	Alpha [$/Wh]	beta [$]	Startup [$]
1	120	20	0.3832	0.2017	2

Based on the datasheet for the batteries used on this microgrid (Trojan t-105) and the inverter technical maximum discharge/charge power (30 kW), the parameters for the battery aging and Peukert effect are obtained and presented in Table 5 and Table 6. This battery has reported average round-trip efficiency of 70-80%, and a throughput capacity of up to 100,000 [kWh] during its useful life and up to 8 years of shelf life. The total cost of the batteries is estimated at 15,000 [$].

Table 5: SoC vs λ_v for Huatacondo.

SoCmax	SoCmin	λ_v
1	0.83	1.03743868
0.83	0.66	0.70656009
0.66	0.49	0.79078909
0.49	0.32	0.75077445

Table 6: Pb vs δ_w for Huatacondo.

Pbmax	Pbmin	δ_w [Ah]
0	8	95.70133
8	16	83.51013
16	30	73.70299

4.1.5 AVAILABLE SERVICES

As a permanently isolated microgrid, the MG has no service to offer to the grid. We will study the possible benefits of implementing DR as an option to compensate the generation fluctuations due to the renewable sources.

4.1.6 SCENARIOS

Considering the previous information, there will be six different scenarios for this case study. The first two will be used to explore the effect of modeling the cycling and Peukert's law BESS phenomena, the third will be used as a base scenario, including all BESS models, and the last three will be used to study the effect of different levels of DR penetration in an isolated MG. Thus the scenarios are:

1. Isolated MG without BESS cycling
2. Isolated MG without Peukert's Law
3. Isolated MG
4. Isolated MG & 10% DR
5. Isolated MG & 20% DR
6. Isolated MG & 30% DR

4.1.7 SCENARIO 1: ISOLATED MG WITHOUT BESS CYCLING

Our first case study simulates the operation of the isolated MG of Huatacondo, without the inclusion of the SoH degradation from cycling the battery. The model will assume a fixed degradation based on calendar life, independent of operation.

Figure 29 presents the operation of the MG. There is one daily startup for the Genset and it operates from 23:40 to 4:40. The Genset was dimensioned to operate during Huatacondo's local saint celebration, when the load increases up to 55-60 [kW]. This means that typically during normal operation the Genset will operate at minimum power.

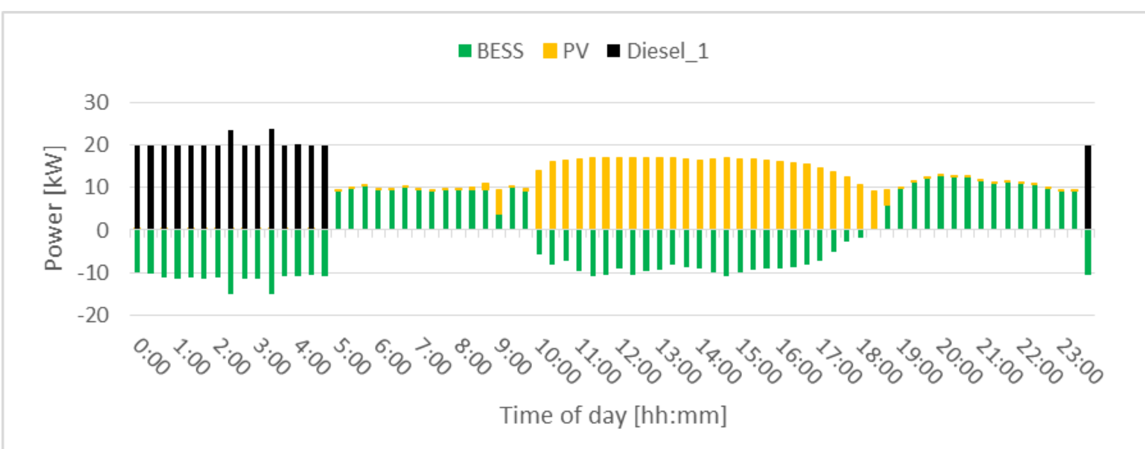

Figure 29: Operation for case study 1

Figure 30 presents the State of Charge for the ESS through the day. The optimized initial state of charge of the BESS is 35%, with two charge-discharge cycles, one charge is done with the diesel generator when the BESS reaches a SoC of 32% between 23:20 and 4:40 and the second charge is performed while the PV plant is generating.

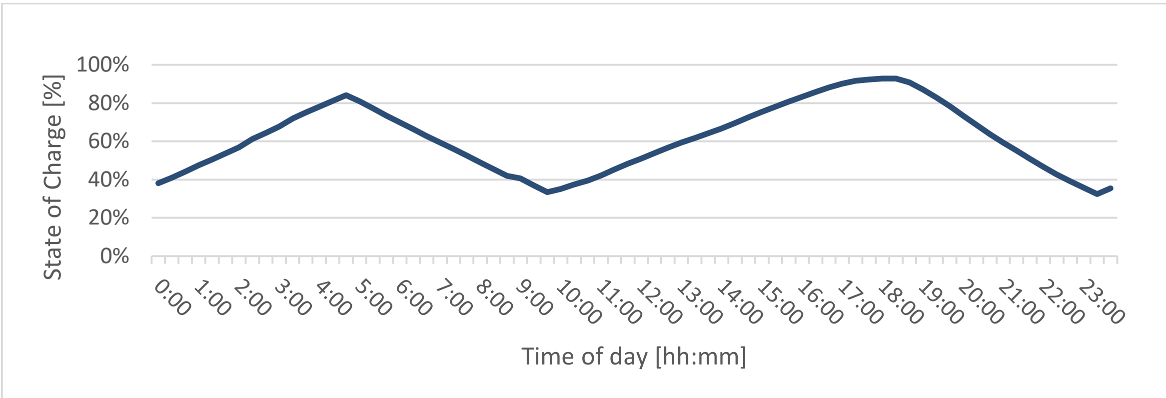

Figure 30: State of Charge for case study 1

Table 7 breaks down the daily operation for each the different elements in the MG, including:

- Operational time, fuel cost and average generation cost of the Diesel generator.
- The expected lifetime of the battery, the cost of usage, average discharged power, discharged energy through the day, usage cost and round trip efficiency.
- The amount of energy not supplied and the penalty associated.

The cost of operating the battery in this way, using the models presented in chapter 3, corresponds to a daily cost of 21.96 [$], a cost that is not included in the optimization of the schedule. As can be seen in Table 7, the lost SoH of the battery represents a 49% of the Genset operation cost. As expected, there is no NSE present.

Table 7: Operation Summary of all units for case study 1

Unit	Item	Value	Units
Diesel	Op. Time	5.3	[h]
	Fuel	44.9	[l]
	Fuel cost	44.9	[$]
	Gen cost	0.411	[$/kWh]
Battery	Ex. Lifetime	910.8	[days]
		2.5	[years]
	Usage value	21.96	[$]

	Disch. Power	9.67	[kW]
	Disch. Energy	99.9	[kWh]
	Usage cost	0.168	[$/kWh]
	Rd. Trip Eff.	76%	[%]
NSE	Energy	0	[kWh]
	Cost	0	[$]
Total cost		66.82	[$]

4.1.8 Scenario 2: Isolated MG without Peukert's Law

The second case study simulates the operation of the isolated MG of Huatacondo, without the inclusion of the Peukert's effect on the discharge of the battery. The model will assume a fixed efficiency of 75% for the battery, independent of the discharge current.

Figure 31 presents the operation of the MG. There are two daily start-ups for the Genset, which operates from 4:00 to 6:40 and from 20:20 to 22:20.

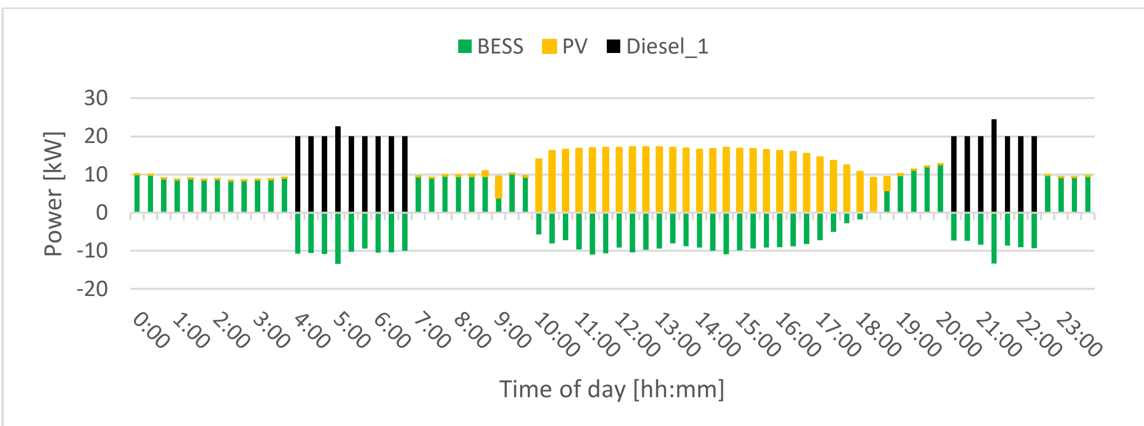

Figure 31: Operation for case study 2

Figure 32 presents the State of Charge for the BESS through the day. The optimized initial state of charge of the BESS is 70%, with two charge-discharge cycles, one done with the Genset when the BESS reaches a SoC of 35% and the second charge is done with a combination of PV and the Genset when the BESS reaches a SoC of 32%.

With the current operation, the battery is expected to last for a little more than 3 years, as seen in Table 8. As expected, there is no NSE present.

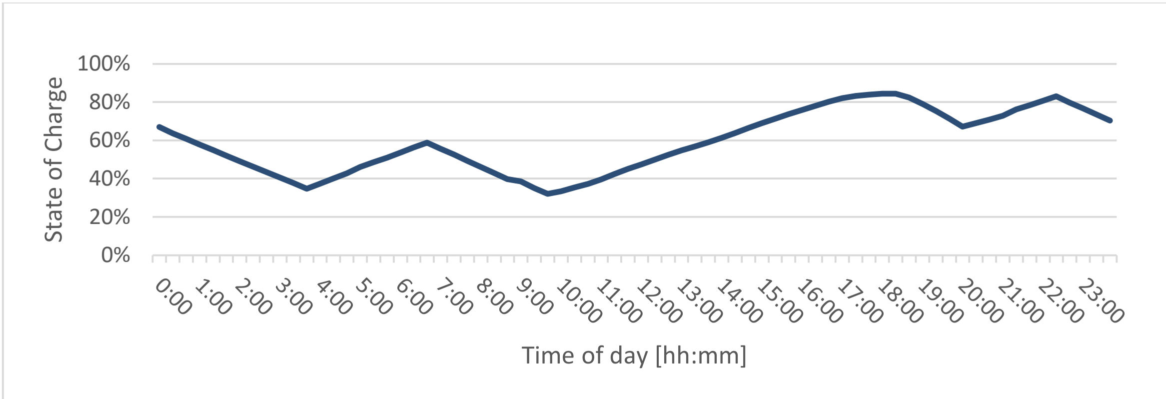

Figure 32: State of Charge for case study 2

Table 8: Operation Summary of all units for case study 2

Unit	Item	Value	Units
Diesel	Op. Time	5.3	[h]
	Fuel	46.9	[l]
	Fuel cost	46.9	[$]
	Gen cost	0.430	[$/kWh]
Battery	Ex. Lifetime	1,125	[days]
		3.08	[years]
	Usage value	17.8	[$]
	Disch. Power	8.94	[kW]
	Disch. Energy	92.4	[kWh]
	Usage cost	0.144	[$/kWh]
	Rd. Trip Eff.	75%	[%]
NSE	Energy	0	[kWh]
	Cost	0	[$]
Total cost		64.64	[$]

4.1.9 Scenario 3: Isolated MG

The third case study simulates the operation of the isolated MG of Huatacondo including both cycling degradation and Peukert's effect.

Figure 33 presents the operation of the MG. In this simulation there are two daily startups for the Genset again, from 3:40 to 6:40 and from 20:40 to 22:20.

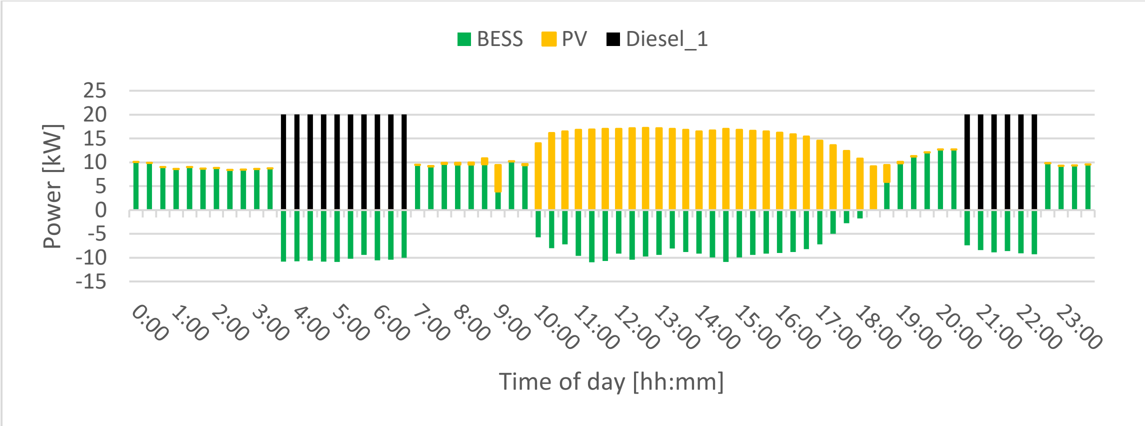

Figure 33: Operation for case study 3

Figure 34 presents the State of Charge for the BESS through the day. The optimized initial state of charge of the BESS is 69%, with two charge-discharge cycles, one done with the diesel generator when the BESS reaches a SoC of 34% and the second charge is done with a combination of PV and the genset when the BESS reaches a SoC of 33%.

With the current operation, the battery is expected to last for a little over 3 years, as can be seen in Table 9. The efficiency of the BESS is also slightly higher than case 2, due to the low current the BESS discharge. As expected, there is no NSE present.

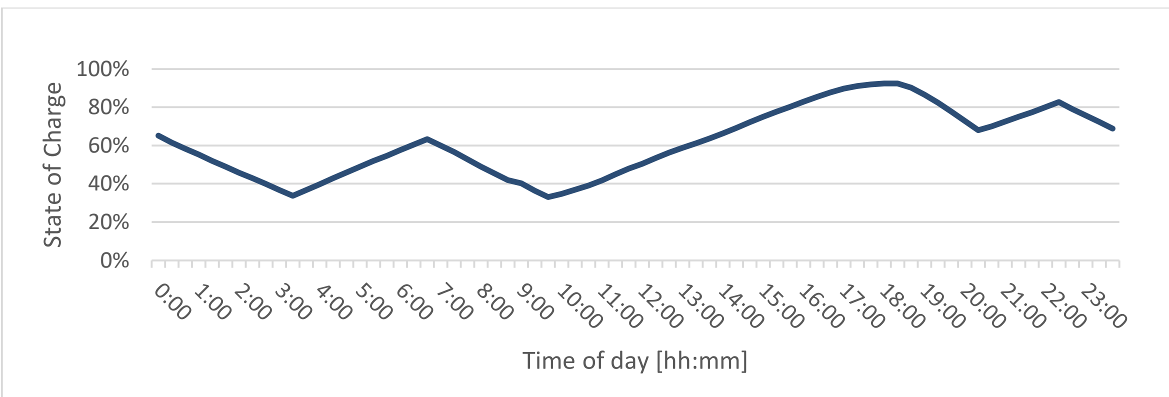

Figure 34: State of Charge for case study 3

Table 9: Operation Summary of all units for case study 3

Unit	Item	Value	Units
Diesel	Op. Time	5.3	[h]
	Fuel	46.0	[l]
	Fuel cost	46.0	[$]
	Gen cost	0.431	[$/kWh]

Battery	Ex. Lifetime	1,105	[days]
		3.03	[years]
	Usage value	18.1	[$]
	Disch. Power	9.05	[kW]
	Disch. Energy	93.5	[kWh]
	Usage cost	0.148	[$/kWh]
	Rd. Trip Eff.	77%	[%]
NSE	Energy	0	[kWh]
	Cost	0	[$]
Total cost		64.06	[$]

4.1.10 Scenario 4: Isolated MG & 10% DR

The fourth case study simulates the operation of the isolated MG of Huatacondo considering the possibility of increasing or reducing the load by up to 10% on any period, without changing the daily electrical consumption.

Figure 35 presents the operation of the MG. In this simulation there are two daily startups for the Genset again, from 4:20 to 6:40 and from 20:20 to 22:20, similar to case study 2 and 3.

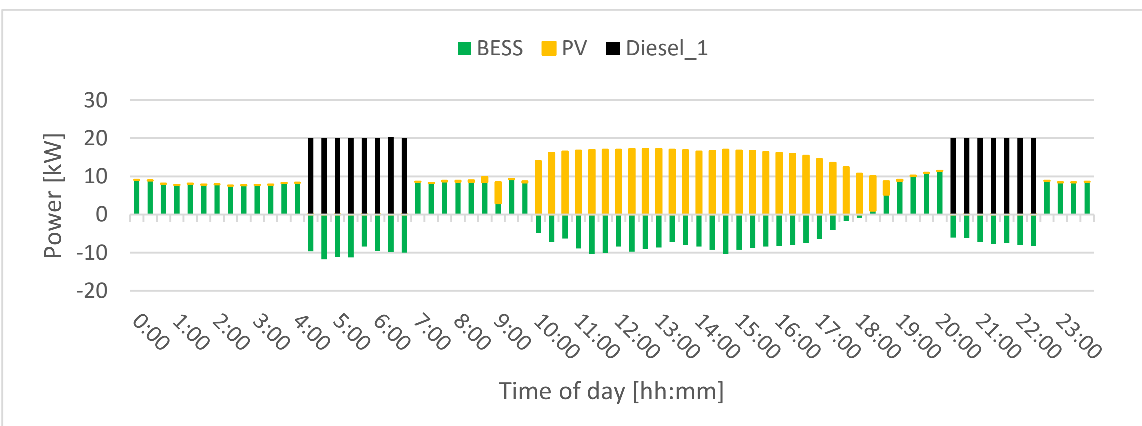

Figure 35: Operation for case study 4

Figure 36 presents the State of Charge for the BESS through the day. The optimized initial state of charge of the BESS is 68%, with two charge-discharge cycles, one done with the diesel generator when the BESS reaches a SoC of 34% and the second charge is done with a combination of PV and the Genset when the BESS reaches a SoC of 32%. The average discharge current for the battery is 8.05 [kW] with a round-trip efficiency of 80%, a 3% improvement in efficiency compared to the scenario without DR.

With the current operation, the battery is expected to last for 3 and a half years, as can be seen in Table 10, an extension in life of almost 16%. As expected, there is no NSE present.

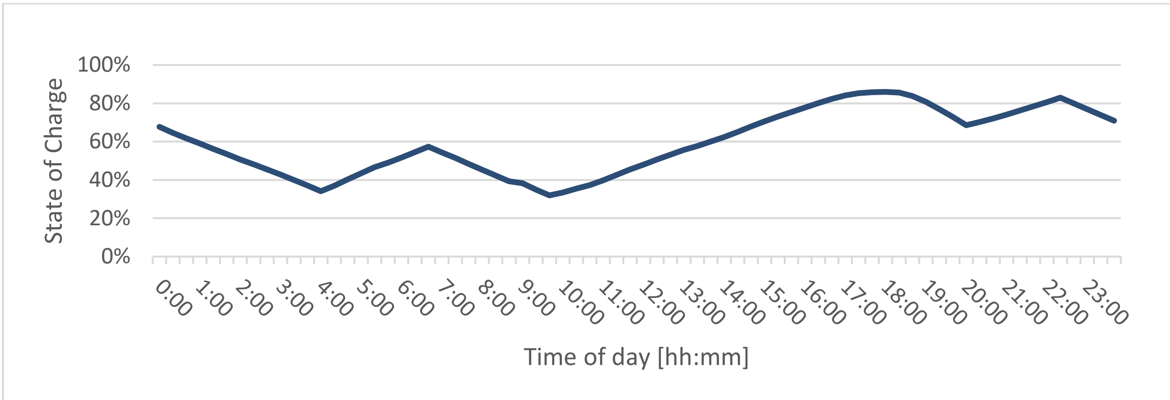

Figure 36: State of Charge for case study 4

Table 10: Operation Summary of all units for case study 4

Unit	Item	Value	Units
Diesel	Op. Time	5.0	[h]
	Fuel	43.4	[l]
	Fuel cost	43.4	[$]
	Gen cost	0.433	[$/kWh]
Battery	Ex. Lifetime	1,277	[days]
		3.5	[years]
	Usage value	15.7	[$]
	Disch. Power	8.05	[kW]
	Disch. Energy	85.8	[kWh]
	Usage cost	0.145	[$/kWh]
	Rd. Trip Eff.	80%	[%]
NSE	Energy	0	[kWh]
	Cost	0	[$]
Total cost		59.04	[$]

The net difference between the unmodified and the modified load is presented in Figure 37. As can be seen, the load is shifted toward the times when the diesel generator is operational (4:20-6:40, 20:20-22:20) or when the PV plant is generating (10:00-18:20). This has the advantage of reducing the use of the BESS, increasing its lifetime by 15.6%, and prevent the losses in the charge-discharge process, especially important in low-efficiency batteries like lead-acid.

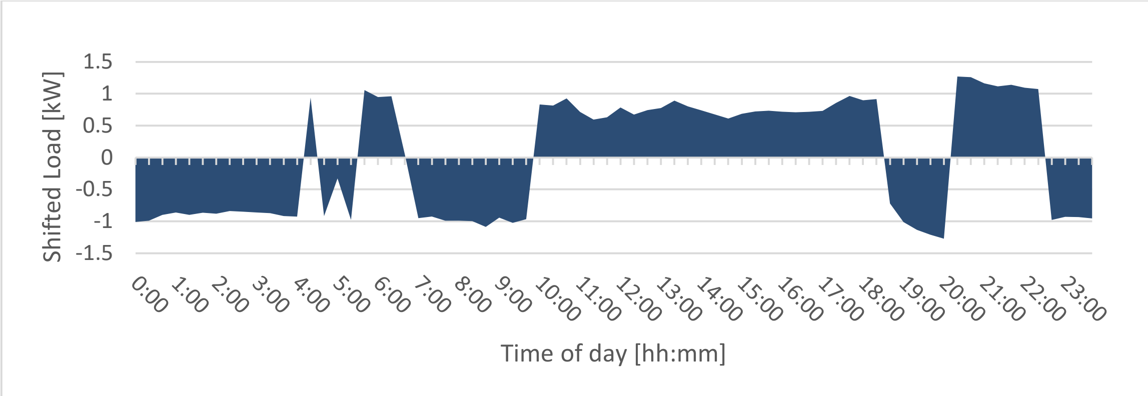

Figure 37: Net shifted Load for case study 4

4.1.11 Scenario 5: Isolated MG & 20% DR

The fifth case study simulates the operation of the isolated MG of Huatacondo, considering the option to increase or reduce the load by up to 20% on any period, without changing the daily electrical consumption.

Figure 38 presents the operation of the MG. In this simulation there are two daily startup for the Genset again, from 5:20 to 7:00 and from 20:00 to 22:20.

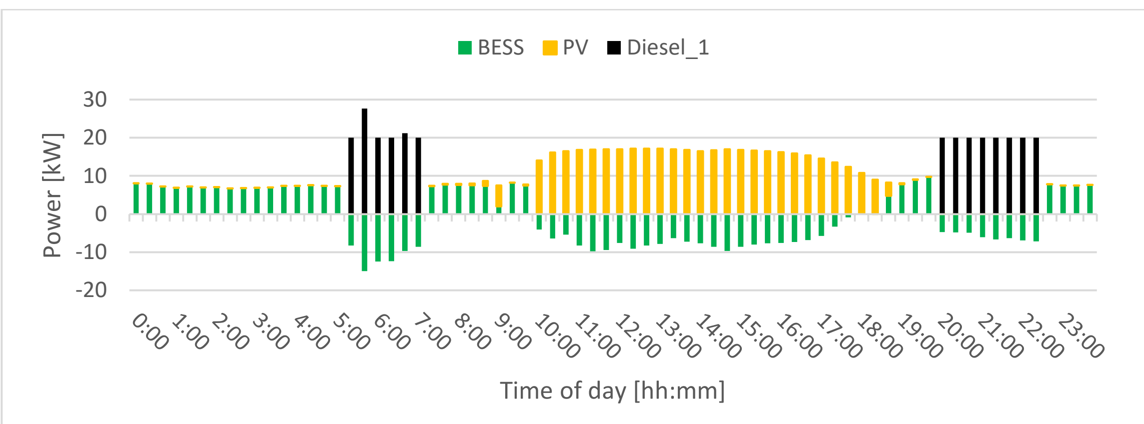

Figure 38: Operation for case study 5

Figure 39 presents the State of Charge for the BESS through the day. The optimized initial state of charge of the BESS is 72%, with two charge-discharge cycles, one done with the diesel generator when the BESS reaches a SoC of 33% and the second charge is done with a combination of PV and the genset when the BESS reaches a SoC of 32%. The round-trip efficiency increases by 1% compared to case study

4. With the current operation, the battery is expected to last a little over 4 years, as can be seen in Table 11. As expected, there is no NSE present.

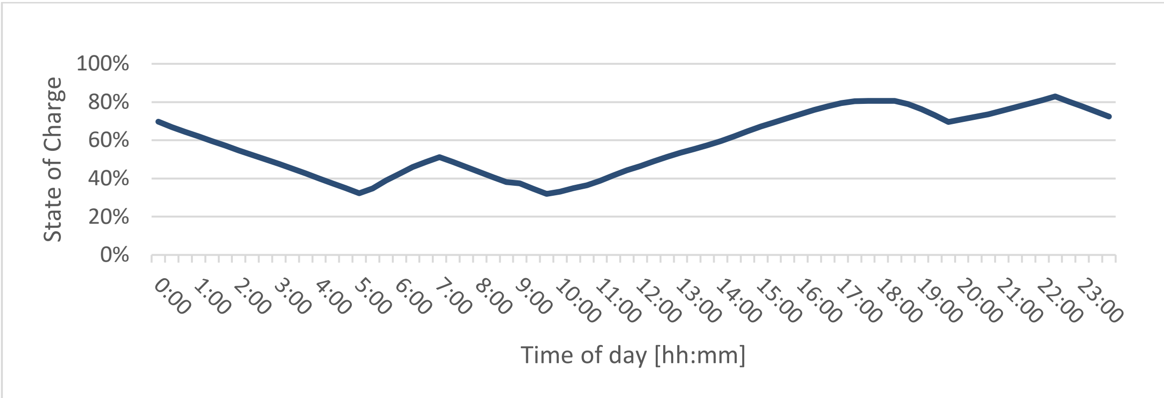

Figure 39: State of Charge for case study 5

Table 11: Operation Summary of all units for case study 5

Unit	Item	Value	Units
Diesel	Op. Time	2.0	[h]
	Fuel	41.8	[l]
	Fuel cost	41.8	[$]
	Gen cost	0.435	[$/kWh]
Battery	Ex. Lifetime	1,473	[days]
		4.04	[years]
	Usage value	13.6	[$]
	Disch. Power	7.23	[kW]
	Disch. Energy	77.2	[kWh]
	Usage cost	0.143	[$/kWh]
	Rd. Trip Eff.	81%	[%]
NSE	Energy	0	[kWh]
	Cost	0	[$]
Total cost		55.41	[$]

Figure 40 presents the net difference in shifted load. As in case study 4, the load is mostly shifted toward times when the diesel generator is operational (5:20-7:00 and 20:00-22:20) or when the PV plant is generating (10:00-18:20). This has the advantage of reducing the use of the BESS, increasing its time of operation by 33.3%, and prevent the losses in the charge-discharge process.

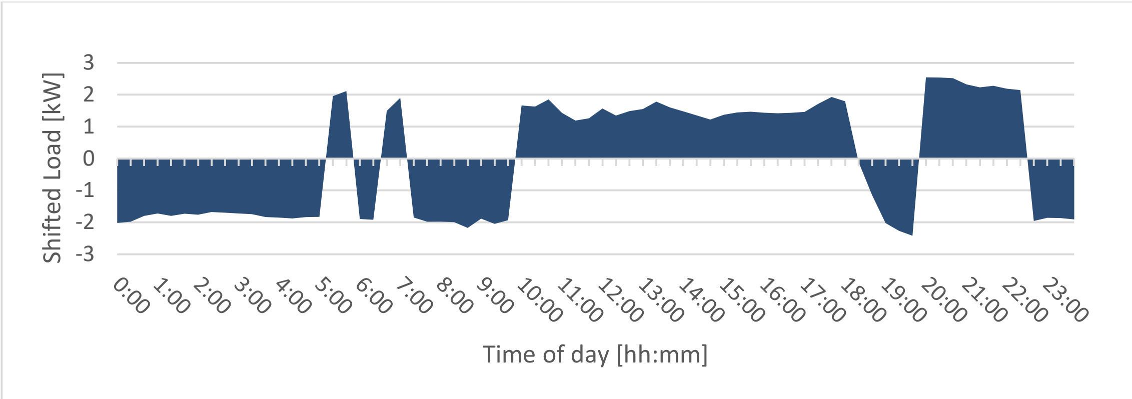

Figure 40: Net shifted Load for case study 5

4.1.12 Scenario 6: Isolated MG & 30% DR

The sixth case study simulates the operation of the isolated MG of Huatacondo, considering the option to increase or reduce the load by up to 30% at any time, without changing the daily electrical consumption.

Figure 41 presents the resulting operation of the MG. In contrast with most of the previous simulations, there is only one startup for the genset in this case, from 20:40 to 1:00. This reduces the diesel usage for start-up, which represents 2/3 of the reduction in cost compared to case study 5.

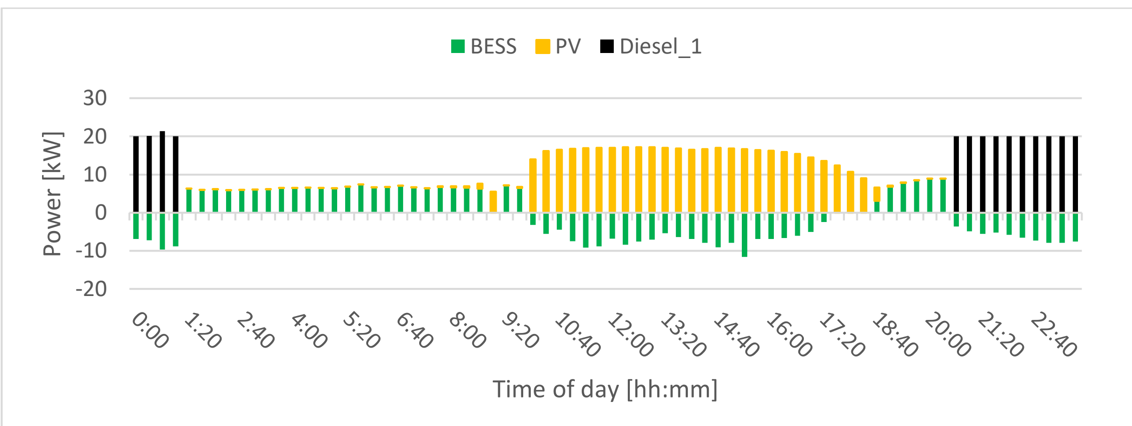

Figure 41: Operation for case study 6

Figure 42 presents the State of Charge for the BESS through the day. The optimized initial state of charge of the BESS is 79%, with one charge-discharge cycles, started by the PV plant and finished by the diesel generator. The lowest SoC for this simulation is 32% at 9:40, when the PV plant power is higher than the load. The average discharge current for the battery is 6.62 [kW] with a resulting round-trip efficiency of 81%. With the current operation, the battery is expected to last almost 4 and a half years, as can be seen in Table 12. As in previous case studies, there is no NSE present.

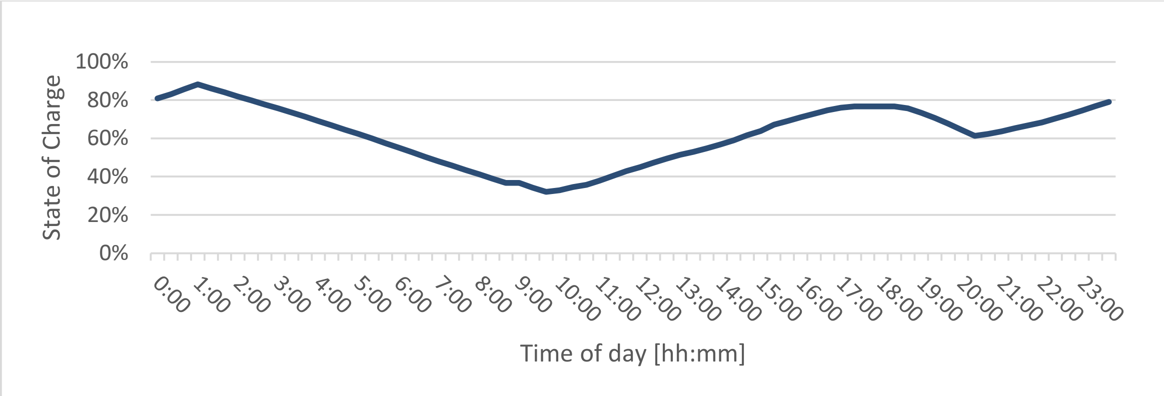

Figure 42: State of Charge for case study 6

Table 12: Operation Summary of all units for case study 6

Unit	Item	Value	Units
Diesel	Op. Time	4.7	[h]
	Fuel	40.1	[l]
	Fuel cost	40.1	[$]
	Gen cost	0.427	[$/kWh]
Battery	Ex. Lifetime	1,618	[days]
		4.43	[years]
	Usage value	12.4	[$]
	Disch. Power	6.62	[kW]
	Disch. Energy	68.4	[kWh]
	Usage cost	0.147	[$/kWh]
	Rd. Trip Eff.	81%	[%]
NSE	Energy	0	[kWh]
	Cost	0	[$]
Total cost		52.42	[$]

Figure 43 presents the net difference in load. As can be seen in this figure, the load is shifted toward the periods when the PV is in full operation (10:00-18:20) or when the Genset is generating (20:40-1:00). This has the advantage of reducing the use of the BESS, increasing its time of operation by 43.8%, and prevents the losses in the charge-discharge process.

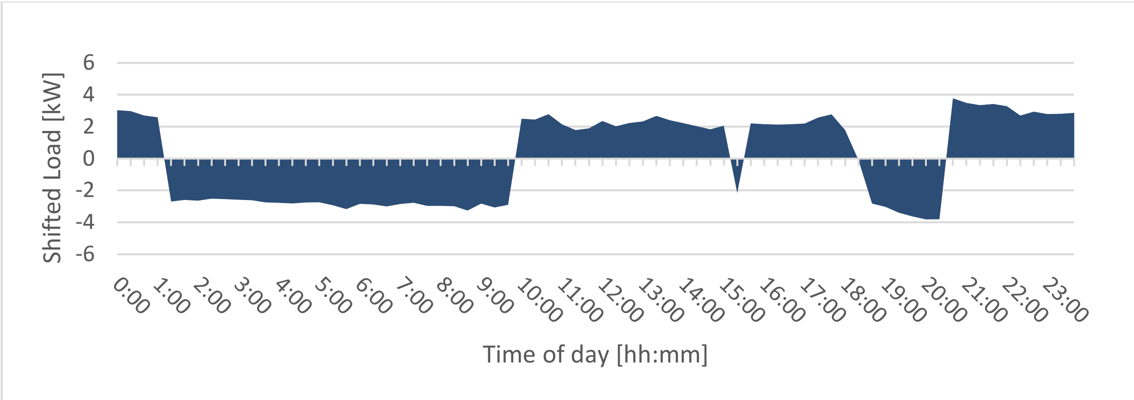

Figure 43: Net shifted Load for case study 6

4.1.13 Result analysis – Huatacondo

Energy management in an isolated MG is crucial, as they have a limited generation capacity, some of which are renewable based and hence intermittent. The first six scenarios have presented a comprehensive mathematical optimization model applied on an existing isolated MG considering six different scenarios to coordinate an islanded microgrid with and without DR on the energy scheduling.

Comparing scenarios 1 and 3, we can see the importance of modeling the state of health degradation based on cycling for the BESS. In scenario 1, where the degradation of the BESS is not modeled in the dispatch, the BESS will last 2.5 years. When the degradation of the BESS is included, scenario 3, the BESS will be operated in such way as to increase its duration to 3.03 years, an increase in duration of 21.3%. There is a small increase in fuel in exchange for a longer duration of the BESS, but the operation and the effective total cost is reduced by including battery cycling degradation. Comparing the total expected operating cost of case studies 1 and 3, presented in Table 13, a net reduction in the operational cost of 4.3% is obtained.

Table 13: Summary of scenarios 1-6

	Op. Cost [$]	Fuel cost [$]	BESS cost [$]	BESS eff. [%]	BESS lifetime [years]	Summary
Scenario 1	$ 66.82	$ 44.86	$ 21.96	76%	2.5	No BESS cycling
Scenario 2	$ 64.64	$ 46.86	$ 17.79	75%	3.08	No Peukert effect
Scenario 3	$ 64.06	$ 45.95	$ 18.11	76%	3.03	-
Scenario 4	$ 59.04	$ 43.38	$ 15.66	80%	3.5	DR 10%
Scenario 5	$ 55.41	$ 41.84	$ 13.57	81%	4.04	DR 20%
Scenario 6	$ 52.42	$ 40.06	$ 12.36	81%	4.43	DR 30%

Scenario 2 and 3 show some of the importance of including the Peukert effect. The inclusion of this effect shows that the BESS efficiency can be higher than the average value for low power operation like Huatacondo's MG, with a 76% efficiency instead of the 75%. Looking at the results in Table 13, the inclusion of the Peukert effect reduces the operational cost by 0.9%. It's important to note that the Huatacondo MG doesn't require high power during its normal operation, so part of the impact of the Peukert effect is not present here.

Scenarios 4, 5 and 6 present the effect of implementing DR on the Huatacondo MG. In these scenarios we can see a common trend, an increase in load when there is renewable energy available or the diesel generator is turned on and a reduction in consumption when the BESS is the one providing the energy. DR has a significant impact on the operational cost, with an 8.5%, 15.6% and 22.2% reduction in scenarios 4, 5 and 6 respectively. This is mainly due to a reduction in load while the BESS is operating, which reduces the discharge current and thus increases the BESS efficiency (Peukert effect) and simultaneously reduces the amount of energy that has to go through the battery (less charging losses). It's important to note that there is both an increase and reduction of the load while the diesel generator is operational. This is due to a lack of penalty from shifting the load, so even if there is no benefit or penalty from shifting the load during these times, the optimizer will maximize/minimize the consumption.

The developed mathematical model efficiently incorporates and manages various supply components, in this case, a diesel generator, a Lead-acid BESS, solar PV panels and the load when DR is implemented. The results successfully demonstrate the effectiveness of the energy management of an isolated MG with and without DR.

4.2 CASE STUDY: CIGRE MG IN ONTARIO

The designed EMS will be tested on the CIGRE medium voltage network presented in [**99**], which has been commonly used to Benchmark Medium Voltage microgrids ([**98**], [**100**]).

4.2.1 MICROGRID TOPOLOGY

The 15-bus test system single-line diagram, at a rated voltage of 10 kV, is shown in Figure 44, which is derived from the diagram presented in [**98**]. The MG has a radial topology and is connected to the main grid. It has critical loads connected to it, so it has to consider the possibility of operating in isolated mode.

The generation resources are confined to four types of DERs: diesel generators, a wind turbine, PV panels, and BESS. Based on the information presented in [**98**], the maximum power of the diesel generators, wind turbine, aggregated PV panels and BESS is presented in Table 14. In the case of the BESS units, the maximum storage capacity (in kWh) is included.

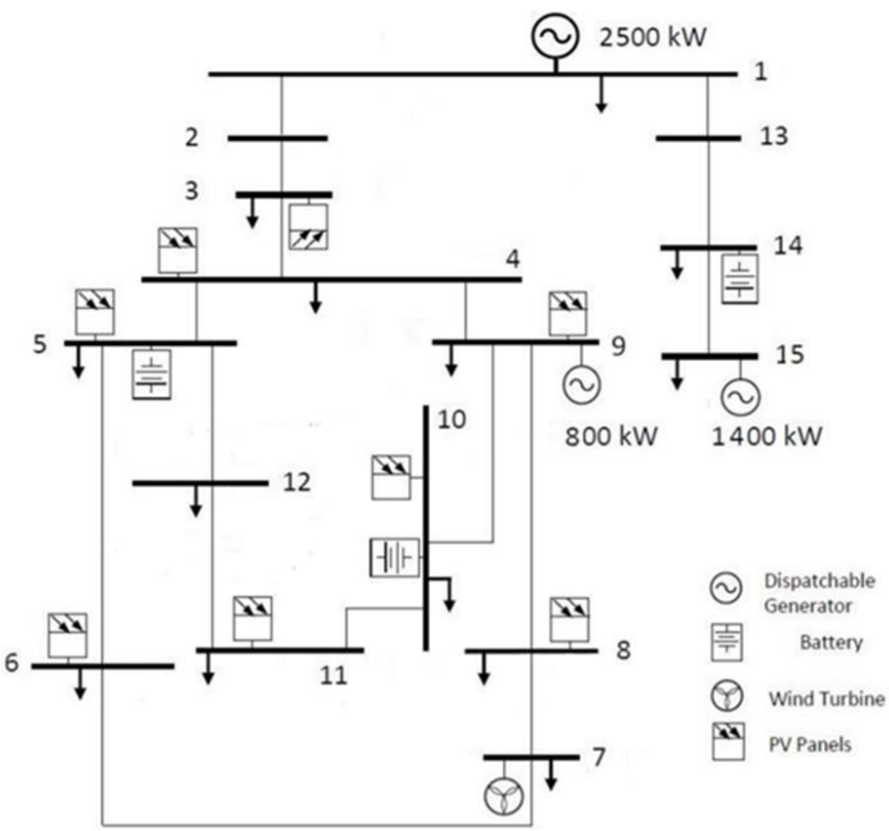

Figure 44: Microgrid Test Based on the CIGRE-IEEE DER Benchmark MV Network [**98**]

Table 14: Summary table of the CIGRE MG DER

DER		Units
Genset 1	2,500	[kW]
Genset 2	1,400	[kW]
Genset 3	800	[kW]
Total PV	210	[kW]
Wind Turbine	1,500	[kW]
Bess 1	300	[kW]
	900	[kWh]
Bess 2	300	[kW]
	900	[kWh]
	300	[kW]
Bess 3	900	[kWh]

4.2.2 LOAD PROFILE

Based on the work presented by Alharbi in [**100**], the loads connected at each bus are either household or commercial. The 24-hour aggregated load profile at each hour is shown in Figure 45, with a peak demand of 1,867 [kW] at hour 19 and an average consumption of 1,279 [kW].

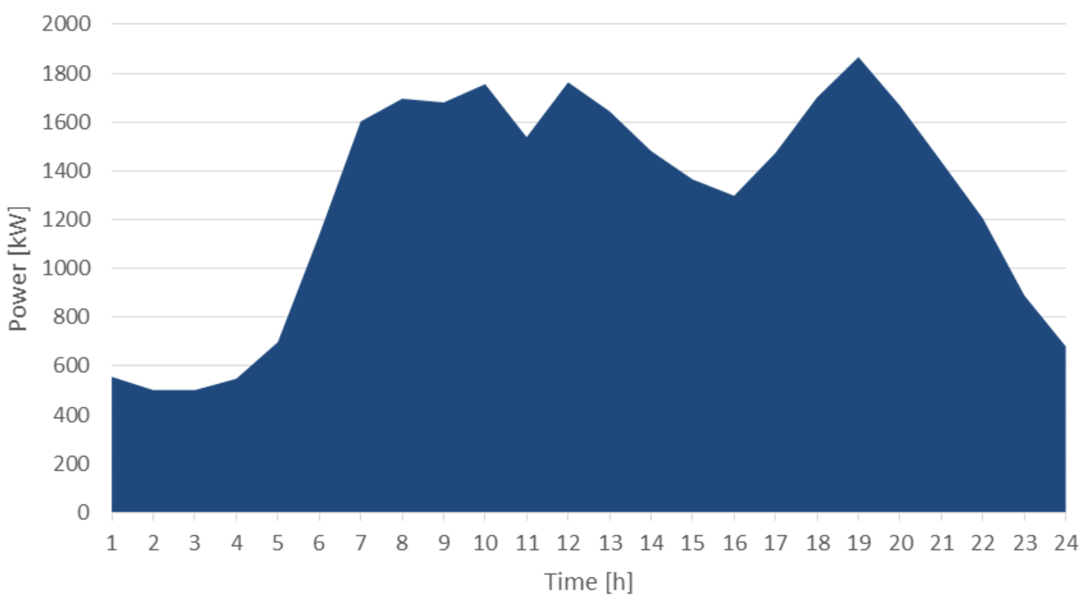

Figure 45: Load Profile for the CIGRE MG.

4.2.3 RENEWABLE RESOURCES

Using the information recollected by Alharbin in [**100**], the wind turbine and PV generation profiles for the simulations are presented in Figure 46, with an average generation of 53.8 [kW] and 419.3 [kW] for the aggregated PV panels and wind turbine respectively. The maximum generation is 177 [kW] and 1.305 [kW] for PV panels and wind turbine respectively.

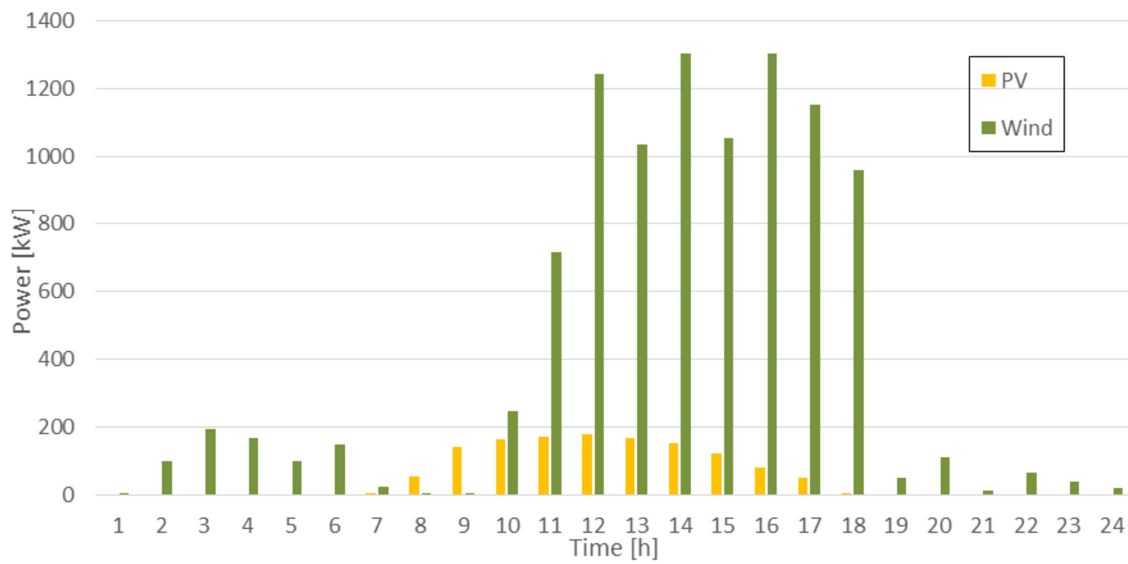

Figure 46: Renewable generation for the CIGRE MG.

4.2.4 UNIT PARAMETERS

The diesel generator operating cost parameters are obtained assuming a diesel price of 1 [USD/l]. The maximum & minimum power, the variable consumption (alpha) and static consumption (beta) of the operating gensets and the startup cost of each of the three diesel generators are presented in Table 15, based on Alharbin's Thesis [**100**].

Table 15: Genset parameters for CIGRE MG.

Unit #	Pmax [kW]	Pmin [kW]	alpha [$/Wh]	beta [$]	Startup [$]
Diesel 1	2,500	625	0.182	40	20
Diesel 2	1,400	350	0.2 .	20	10
Diesel 3	800	200	0.215	10	5

In this case, two different BESS technologies will be considered: Lead-Acid and Sodium.

Based on the datasheet for typical lead-acid batteries, the inverter maximum discharge/charge power (3x 300 [kW]) and the capacity (3x 900 [kWh]), the parameters for battery aging and Peukert effect are obtained, presented in Table 16 and Table 17. This BESS has an average round-trip efficiency of 70-80%, a combined maximum throughput capacity of up to 1,684,800 [kWh] during its useful life and up to 8 years of shelf life. The cost of this battery was estimated at 1,000,000 [USD].

Table 16: SoC vs λ_v for CIGRE LA BESS.

SoCmax	SoCmin	λ_v
1	0.8	1.03743868
0.8	0.6	1.00677767
0.6	0.4	1.14637189
0.4	0.2	0.91878296

Table 17: Pb vs δ_w for CIGRE LA BESS.

Pbmax	Pbmin	δ_w [Ah]
0	225	2,449.312
225	450	2,033.907
450	675	1,742.716
675	900	1,575.74

Based on the datasheet for sodium sulfur batteries, the inverter maximum discharge/charge power (900 kW) and capacity (2,700 [kWh]), the parameters for battery aging and Peukert's effect are obtained, presented in Table 18 and Table 19. This battery has reported average round-trip efficiency of 80-92%, a maximum throughput capacity of up to 9,244,800 [kWh] during its useful life and up to 20 years of shelf life. The cost of this battery was estimated at 2,500,000 [$].

Table 18: SoC vs λ_v for CIGRE NaS.BESS

SoCmax	SoCmin	λ_v
1	0.8	1.03743868
0.8	0.6	1.00677767
0.6	0.4	1.14637189
0.4	0.2	0.91878296

Table 19: Pb vs δ_w for CIGRE NaS.BESS.

Pbmax	Pbmin	δ_w [Ah]
0	225	2,533.76
225	450	2,193.957
450	675	1,915.306
675	900	1,697.807

4.2.5 AVAILABLE SERVICES

Considering the current electrical regulation in Ontario, there are three possible services that a MG can offer: arbitrage, offering active power reserve and more recently, a cap-and-trade system for carbon is being implemented in Ontario which makes emission reduction a viable service.

The Independent Electricity System Operator (IESO) in Ontario has a Time-of-Use electricity Price (see [**101**]), which changes based on the Summer-Winter seasons, weekends and holidays.

During weekends and holidays, the price is considered off-peak at a price of 6.5 [cents/kWh]. In summer and winter, between 7 PM and 7 AM, the price is also considered off-peak at the same price.

In summer, the peak price (13.2 cents/kWh) is it highest between 11:00 and 17:00. In winter, the peak price occurs between 7:00 to 11:00 and between 17:00 to 19:00. The mid-peak rate (9.5 cents/kWh) is applied on the remaining hours. Figure 47 presents this information graphically. For the following simulations, we will use winter's time-of-use price.

Figure 47: Electricity Time-of-Use Price Profile for Ontario. Based on [**101**] & [**102**]

In Ontario, the price of active power support depends on response time, with prices ranging from 9.2 [cents/kW] for units that respond in less than 10 minutes to 2.2 cents for units that respond in up to 30 minutes. The MG DR and generation unit can have a fast response, so the price of 9.2 [cents/kw] will be considered for active power support.

Canada will impose a national carbon price in 2018 [**103**]. The initial price will be a minimum of 10 Canadian dollars per metric ton ("tonne") of CO2, and it will increase annually by 10 [$/tonne] until it reaches 50 [$/tonne] in 2022. Ontario's energy is supplied mostly by nuclear generation, followed by Hidro, Gas, Wind and some Biofuel. The main Co2 generators in the grid are the Gas turbines, representing around a 10% of the total generation. A week of operation during winter is presented in Figure 48. As presented in [104]. On average Gas turbines generate on average 0.15 [ton/MWh], which is the value used for these simulations with a penalization of 10 [$/ton]. More information on this topic is presented on Annex I.

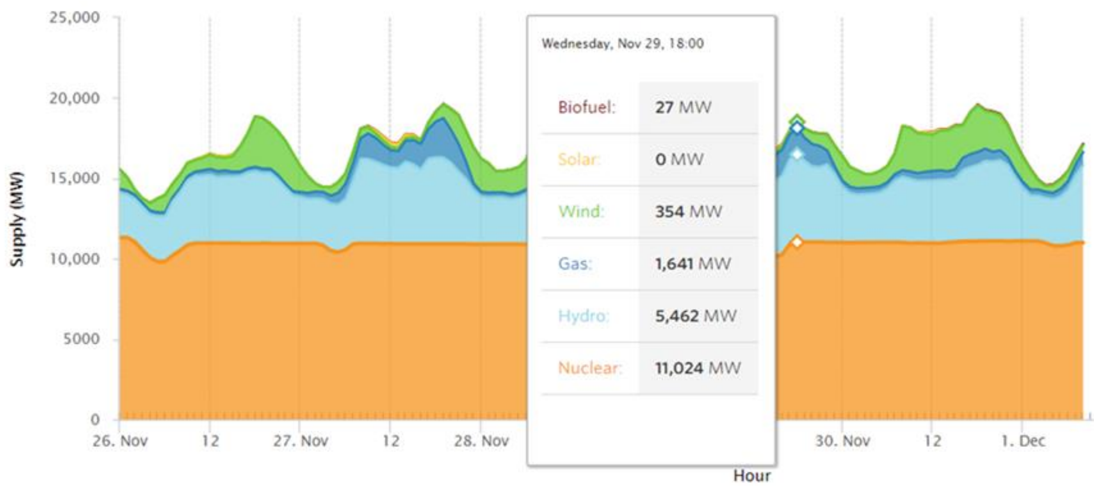

Figure 48: Generation matrix for Ontario, from 26-Nov-2017 to 1-Dec-2017. [105]

For the evaluation of islanded operation reliability, a value of lost load (VoLL) of 1 [$/kWh] will be considered. For DR, a maximum demand increase and a decrease of 20% will be considered for each period, maintaining the total consumption through the day.

4.2.6 SCENARIOS

Considering the previous information, there will be six different scenarios for this case study. The seventh and eight scenarios will be used to compare the effect of using two different BESS technologies, LA and NaS. the ninth will be used as a base scenario, including emission reductions and arbitrage. The tenth scenario won’t include the calendar life BESS phenomenon, to see its importance on a connected MG. The eleventh and twelfth scenarios will study the effect of offering spinning reserve to the grid, with and without DR. Thus the scenarios are:

7. Connected MG, LA BESS
8. Connected MG, Na BESS
9. Connected MG, emission reduction& arbitrage

10. Connected MG, emission reduction& arbitrage & no calendar life.
11. Connected MG, emission reduction, arbitrage & spinning reserve
12. Connected MG, emission reduction, arbitrage, spinning reserve & demand response

4.2.7 SCENARIO 7: CONNECTED MG, LA BESS

Our seventh case study simulates the operation of the connected MG of CIGRE, without offering any other service and using a Lead-acid based BESS

Figure 49 presents the operation of the connected CIGRE MG. As can be seen in the graph, most of the demand is supplied from the Grind (16,213 [kWh]). During peak hours, the BESS injects 484.2 [kWh]. The renewable energy generated by the PV and Wind is mostly used to supply the internal load. The excess energy is partially used to recharge the battery (628 [kWh]) and part of it is injected back to the main Grid (438 [kWh]), even with no payment for it.

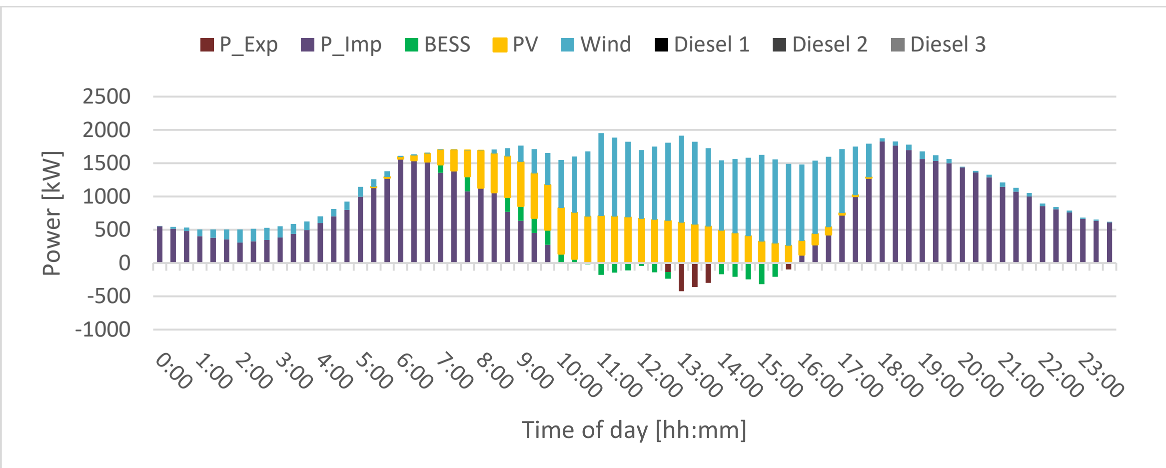

Figure 49: Operation for case study 7

Table 20 breaks down the daily operation for the different elements in the MG, including:

- Operational time, fuel cost and average generation cost of the Diesel generator.
- The expected lifetime of the battery, the cost of usage, average discharged power, discharged energy through the day, usage cost and round trip efficiency.
- The daily energy and revenue from exporting energy to the grid
- The daily energy and cost from importing energy from the grid
- The amount of energy not supplied and the penalty associated.

Looking at Table 20, we can see that the optimizer tries to minimize the usage of the BESS; using it just enough to ensure it will last for its shelf life (8 years). Using the battery to store the additional 438 [kWh] would be more expensive than buying it from the Grid at peak price (0.545 [$] vs 0.132[$]).

Table 20: Operation Summary of all units for case study 7

Unit	Item	Value	Units
Diesel	Op. Time	0	[h]
	Fuel	0	[l]
	Fuel cost	0	[$]
	Gen cost	0	[$/kWh]
Battery	Exp. Lifetime	2,920	[days]
		8	[years]
	Usage value	342.5	[$]
	Disch. Power	181	[kW]
	Disch. Energy	484.2	[kWh]
	Usage cost	0.545	[$/kWh]
	Rd. Trip Eff.	77%	[%]
Exp Grid	Energy	438	[kWh]
	Total Cost	0	[$]
	Av. Cost	0	[$/kWh]
Imp Grid	Energy	16,213	[kWh]
	Total Cost	1,655.8	[$]
	Av. Cost	0.102	[$/kWh]
NSE	Energy	0	[kWh]
	Cost	0	[$]
Total cost		1,998.3	[$]

4.2.8 Scenario 8: Connected MG, Na BESS

Similar to the former case study, our eighth case study simulates the operation of the connected MG of CIGRE, without offering any other service and using Sodium based BESS instead of LA.

Figure 50 presents the operation of the connected CIGRE MG. As can be seen in the graph, most of the demand is supplied from the grid (15,767 [kWh]). During peak hours, the BESS injects 1,230.3 [kWh]. The renewable energy generated by the PV and Wind is used to supply the internal load, either directly or through the BESS. The BESS charges part of its power from renewable generation (467 [kWh]) and the rest from the grid (900 [kWh]).

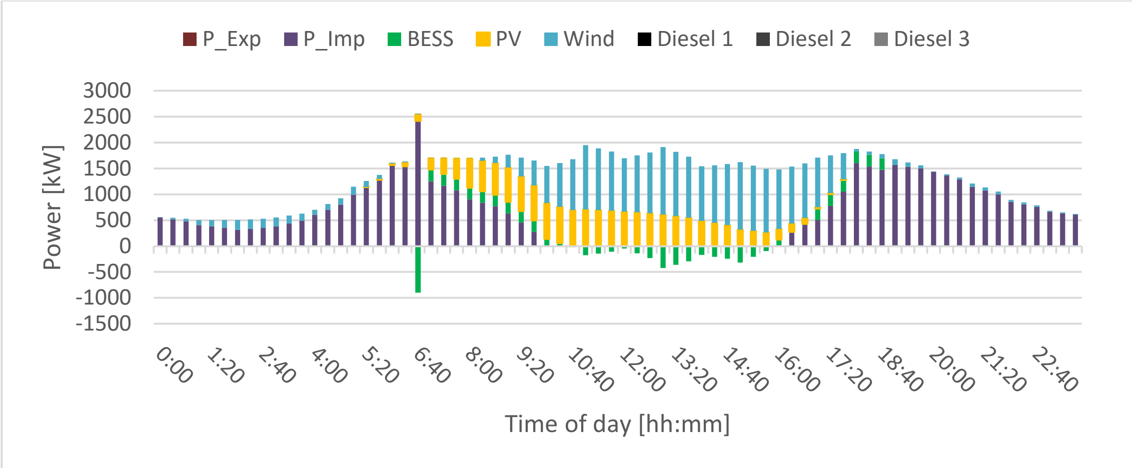

Figure 50: Operation for case study 8

Looking at Table 21, we can see that the optimizer tries to minimize the usage of the BESS, using it just enough to ensure it will last for its shelf life (20 years). As expected, there is no NSE present.

Based on the results from Case Study 7 and 8, which shows that the NaS BESS has better performance than LA, all following simulations for case 4.2 will consider a NaS BESS.

Table 21: Operation Summary of all units for case study 8

Unit	Item	Value	Units
Diesel	Op. Time	0	[h]
	Fuel	0	[l]
	Fuel cost	0	[$]
	Gen cost	0	[$/kWh]
Battery	Ex. Lifetime	7,300	[days]
		20	[years]
	Usage value	342.5	[$]
	Disch. Power	205	[kW]
	Disch. Energy	1,230.3	[kWh]
	Usage cost	0.251	[$/kWh]
	Rd. Trip Eff.	90%	[%]
Exp Grid	Energy	0	[kWh]
	Total Cost	0	[$]
	Av. Cost	0	[$/kWh]
Imp Grid	Energy	15,767	[kWh]
	Total Cost	1,579	[$]
	Av. Cost	0.1	[$/kWh]
NSE	Energy	0	[kWh]
	Cost	0	[$]

Total cost	1,921.02	[$]

4.2.9 Scenario 9: Connected MG, emission reduction & arbitrage

Our ninth case study simulates the operation of the connected MG of CIGRE, now able to buy and sell energy to the grid, considering CO_2 emissions and using Sodium based BESS.

Figure 51 presents the operation of the connected CIGRE MG. As can be seen in the graph, most of the demand is supplied from the Grind (16,989 [kWh]). During on-peak hours, the MG injects 1,223 [kWh] and during off-peak hours the BESS charges from the Grid 1,352 [kWh]. The renewable energy generated by the PV and Wind is used to supply the internal load directly and the remaining energy is exported to the main Grid during peak hours.

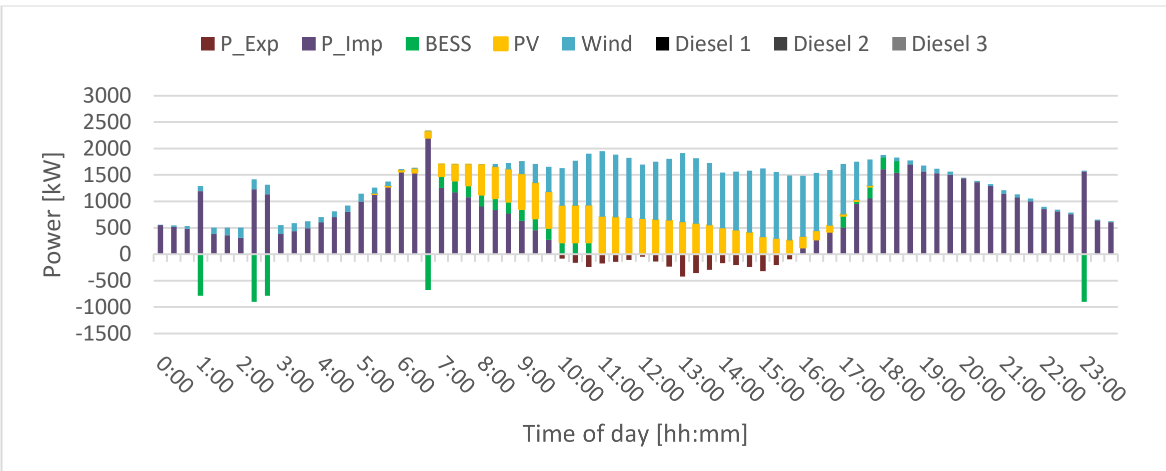

Figure 51: Operation for case study 9

Table 22 includes the revenue obtained from arbitrage (the difference between revenue from exported energy and payments from importing energy) and the revenue obtained from reduced emissions of CO2. Table 22 shows that the optimizer reduces the use of the BESS, using it just enough to ensure it will last for its shelf life (20 years). The BESS is used to reduce the amount of imported energy during on-peak hours, not arbitrage, as can be seen on Figure 51.

Table 22: Operation Summary of all units for case study 9

Unit	Item	Value	Units
Diesel	Op. Time	0	[h]
	Fuel	0	[l]

	Fuel cost	0	[$]
	Gen cost	0	[$/kWh]
Battery	Ex. Lifetime	7,300	[days]
		20	[years]
	Usage value	342.5	[$]
	Disch. Power	215	[kW]
	Disch. Energy	1,217.62	[kWh]
	Usage cost	0.253	[$/kWh]
	Rd. Trip Eff.	90%	[%]
Exp Grid	Energy	1,223	[kWh]
	Total Cost	139	[$]
	Av. Cost	0.11	[$/kWh]
Imp Grid	Energy	16,989	[kWh]
	Total Cost	1,679	[$]
	Av. Cost	0.099	[$/kWh]
NSE	Energy	0	[kWh]
	Cost	0	[$]
Arbitrage	Revenue	(1,541)	[$]
Emissions	Revenue	2.4	[$]
	Energy	1,223.15	[kWh]
	Av. Cost	0.00195	[$/kWh]
Total cost		1,880.90	[$]

4.2.10 Scenario 10: Connected MG, emission reduction, arbitrage & no calendar life

Our tenth case study simulates the operation of the connected MG of CIGRE, able to buy and sell energy but without offering any other service, using a sodium based BESS and without modeling the limited calendar life of the BESS.

Figure 52 presents the operation of the connected CIGRE MG. As can be seen in the graph, most of the demand is supplied from the Grid (16,698 [kWh]). The renewable energy generated by the PV and wind turbines is used to supply the internal load. All energy in excess is sold to the Grid. The BESS is not used.

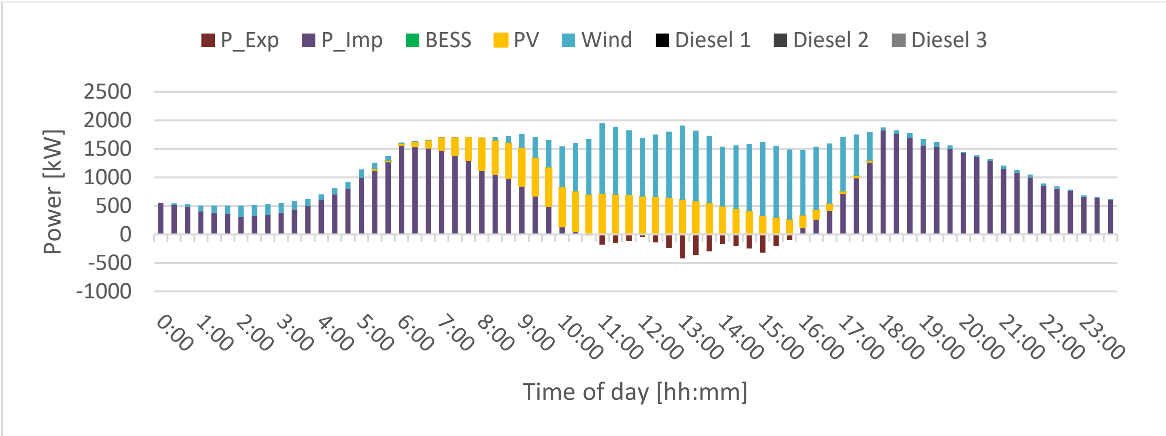

Figure 52: Operation for case study 10

Looking at Table 23, we can see that the optimizer doesn't make use of the BESS. Compared with case 9, we have a higher total cost. This is cause by the EMS ignoring the limited shelf life of 20, thus not making proper use of the BESS. This shows the importance of including the calendar life for grid-connected MG.

Table 23: Operation Summary of all units for case study 10

Unit	Item	Value	Units
Diesel	Op. Time	0	[h]
	Fuel	0	[l]
	Fuel cost	0	[$]
	Gen cost	0	[$/kWh]
Battery	Ex. Lifetime	7,300	[days]
		20	[years]
	Cal. Degradation	342.5	[$]
	Disch. Energy	0	[kWh]
	Usage cost	0	[$/kWh]
	Rd. Trip Eff.	-	[%]
Exp Grid	Energy	1,066	[kWh]
	Total Cost	117	[$]
	Av. Cost	0.11	[$/kWh]
Imp Grid	Energy	16,698	[kWh]
	Total Cost	1,721	[$]
	Av. Cost	0.103	[$/kWh]
NSE	Energy	0	[kWh]
	Cost	0	[$]
Emissions	Revenue	2.1	[$]
	Energy	1,065.67	[kWh]

	Av. Cost	0.00195	[$/kWh]
Total cost		1,944.22	[$]

4.2.11 Scenario 11: Connected MG, emission reduction, arbitrage & spinning reserve

Our eleventh case study simulates the operation of the CIGRE MG, able to buy and sell energy to the grid, considering CO2 cap-and-trade and using Sodium based BESS. In addition, the MG can offer active power reserve to the Grid, ready to increase or reduce its power in less than 10 minutes.

Figure 53 presents the operation of the connected CIGRE MG. As can be seen in the graph, most of the demand is supplied from the Grind (16,967 [kWh]). During on-peak hours, the MG injects 1,201 [kWh] and during off-peak hours the BESS charges from the Grid 1,352 [kWh]. The renewable energy generated by the PV and Wind is used to supply the internal load directly and the remaining energy is exported to the main Grid during peak hours.

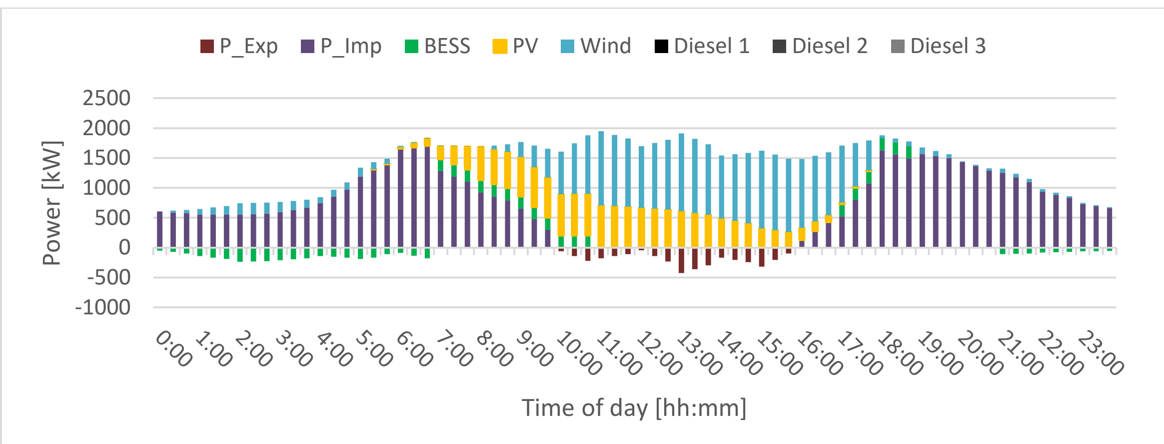

Figure 53: Operation for case study 11

Table 24 now includes the reserve provided by the microgrid (up and down) and the revenue obtained from it. We can see that the optimizer reduces the use of the BESS; using it just enough to ensure it will last for its shelf life (20 years). The BESS is used to reduce the amount of imported energy during on-peak hours.

Table 24: Operation Summary of all units for case study 11

Unit	Item	Value	Units
Diesel	Op. Time	0	[h]
	Fuel	0	[l]

	Fuel cost	0	[$]
	Gen cost	0	[$/kWh]
Battery	Ex. Lifetime	7,300	[days]
		20	[years]
	Usage value	342.5	[$]
	Disch. Power	203	[kW]
	Disch. Energy	1,217.62	[kWh]
	Usage cost	0.253	[$/kWh]
	Rd. Trip Eff.	90%	[%]
Exp Grid	Energy	1,201	[kWh]
	Total Cost	136	[$]
	Av. Cost	0.113	[$/kWh]
Imp Grid	Energy	16,967	[kWh]
	Total Cost	1,676	[$]
	Av. Cost	0.099	[$/kWh]
NSE	Energy	0	[kWh]
	Cost	0	[$]
Reserve	Revenue	14.8	[$]
	Power up	2,972.06	[kW]
	Power down	231.73	[kW]
Emissions	Revenue	2.3	[$]
	Energy	1,201.09	[kWh]
	Av. Cost	0.001950	[$/kWh]
Total cost		1,866.16	[$]

Figure 54 presents the maximum capacity to increase the MG active power injection (Reserve Up) or the MG active power absorption (Reserve Down) for each period. The MG can only offer the lowest value of reserve available at any time. In this simulation, the MG offers up to 5,397.06 [kW] active power injection at any time during the day, which is the lowest possible value available from 7:20 to 10:40 and from 17:00 to 18:40. Most of this power can be provided by the diesel generators (4,700 [kW]), with the remaining 697 [kW] being provided by the BESS.

The MG also has the capability of increasing its active power consumption by up to 848.7 [kW], which is a combination of maximizing the power the battery can absorb and curtailing the generation of the Wind turbine and PV plant. The minimum, 231.73 [kW], is obtained during the night when the wind turbine generation is low and the photovoltaic panels don’t generate any energy.

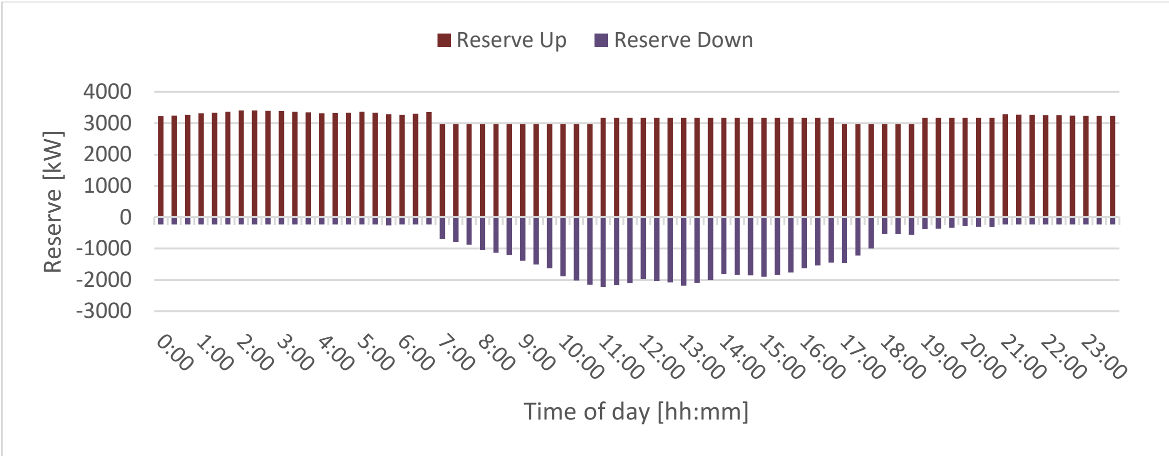

Figure 54: Reserve case study 11

4.2.12 Scenario 12: Connected MG, emission reduction, arbitrage, spinning reserve & demand response

Our twelfth case study simulates the operation of the connected MG of CIGRE, able to sell and buy energy from the grid, considering CO2 cap-and-trade, using Sodium based BESS and offering active power support. In addition, the MG has the capacity to increase or reduce its load by up to 10% in each period, maintaining the same daily consumption.

Figure 55 presents the operation of the connected CIGRE MG. As can be seen in the figure, most of the demand is supplied by the grind (17,507 [kWh]). During on-peak hours, the MG injects 1,741 [kWh] to the grid and during off-peak hours the BESS absorbs 1,351 [kWh] from the Grid. The renewable energy generated by the PV and wind turbine is used to supply the internal load directly and the remaining energy is exported to the main Grid during peak hours.

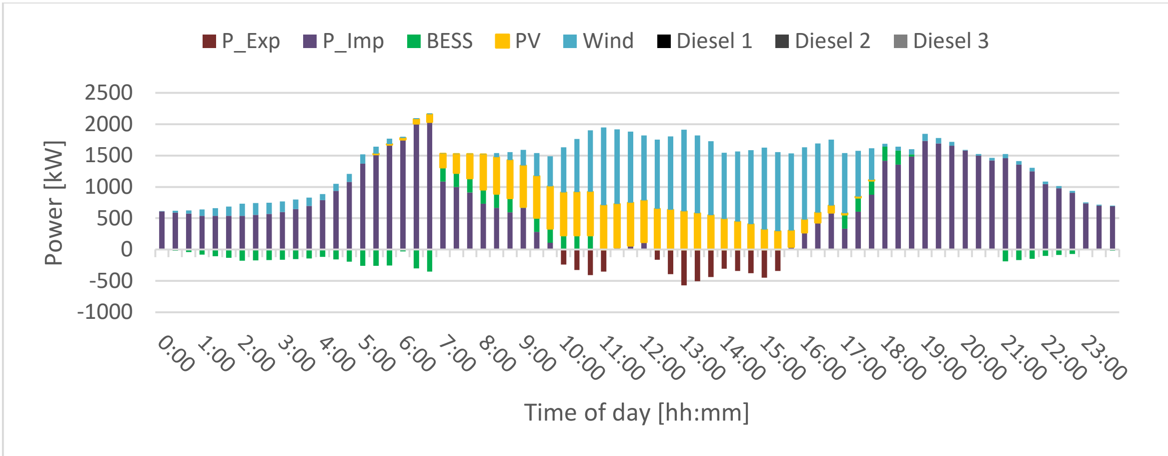

Figure 55: Operation for case study 12

Looking at Table 25, we can see that the optimizer reduces the use of the BESS; using it just enough to ensure it will last for its shelf life (20 years). The BESS is used to reduce the amount of imported energy during on-peak hours.

Table 25: Operation Summary of all units for case study 12

Unit	Item	Value	Units
Diesel	Op. Time	0	[h]
	Fuel	0	[l]
	Fuel cost	0	[$]
	Gen cost	0	[$/kWh]
Battery	Ex. Lifetime	7,300	[days]
		20	[years]
	Usage value	342.5	[$]
	Disch. Power	203	[kW]
	Disch. Energy	1,217.6	[kWh]
	Usage cost	0.253	[$/kWh]
	Rd. Trip Eff.	90%	[%]
Exp Grid	Energy	1,741	[kWh]
	Total Cost	200	[$]
	Av. Cost	0.115	[$/kWh]
Imp Grid	Energy	17,507	[kWh]
	Total Cost	1,685	[$]
	Av. Cost	0.096	[$/kWh]
NSE	Energy	0	[kWh]
	Cost	0	[$]
Arbitrage	Revenue	(1,485)	[$]
Reserve	Revenue	30.5	[$]

	Power up	5,600	[kW]
	Power down	1,017.8	[kW]
Emissions	Revenue	3.4	[$]
	Energy	1,741	[kWh]
	Av. Cost	0.00195	[$/kWh]
Total cost		1,793.89	[$]

Figure 56 presents the maximum capacity to increase the MG active power injection (Reserve Up) or the MG active power absorption (Reserve Down) for each period. The MG can offer daily only the lowest value of reserve available on any period. In this simulation the MG offers up to 5,600 [kW] active power injection at any time during the day, which is the lowest possible value available at 00:00, from 11:20 to12:00, from 15:40 to 16:40, from 19:00 to 20:40 and at 23:20. Most of this power can be provided by the diesel generators (4,700 [kW]), with the remaining 900 [kW] being provided by the BESS.

The MG also has the capability of increasing its active power consumption by up to 1,017.8 [kW], which is a combination of maximizing the power the battery can absorb, increasing demand and curtailing the generation of the Wind turbine and PV plant. The minimum is obtained during the night (21:00-6:40) when the wind turbine generation is low and the photovoltaic panels don't generate any energy.

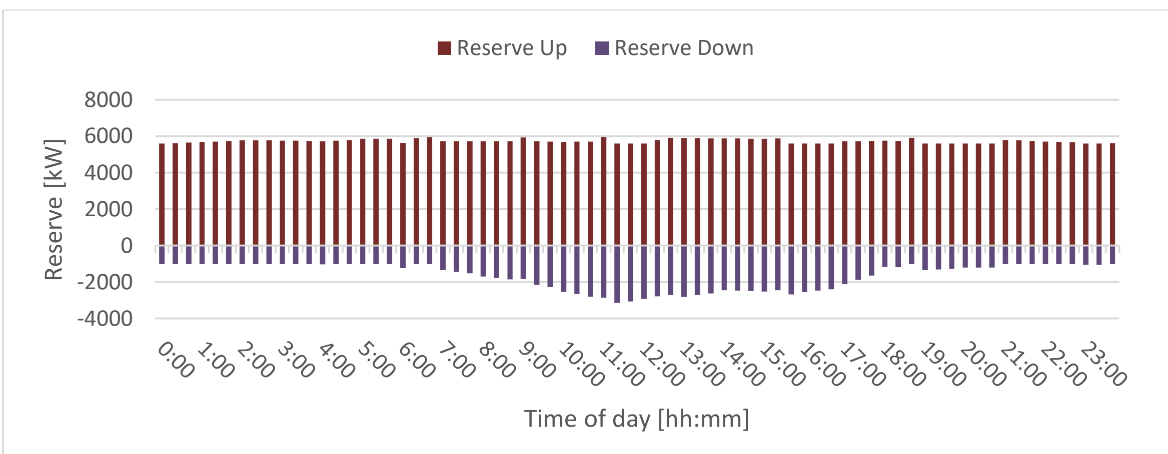

Figure 56: Reserve case study 12

The net difference between the base load and the load after applying Demand response is presented in Figure 57, where it is possible to see how the during peak hours (7:00-11:00, 17:00-19:00) and between 11:20 and 12:00 the load is reduced while in the off-peak hours (19:00-6:40) and just after and before peak-hours the load is increased.

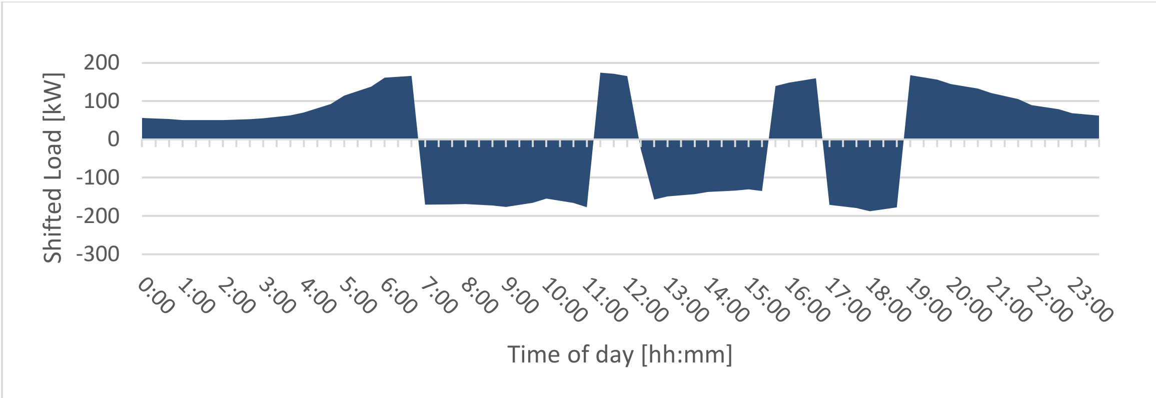

Figure 57: Net shifted Load for case study 12

4.2.13 Result analysis – Ontario

Energy management in connected microgrids has a main difference to the isolated MG: it has access to an unlimited energy source, making the BESS an element used mostly for other services, such as reliability for the consumers, power support or arbitrage.

Scenarios 7 and 8 show the operation of a connected MG using two different BESS technologies: Lead-Acid and Sulfur-Metal. While the investment cost for the LA BESS is lower, the increased cycles, efficiency and calendar life of the Na BESS allows Case 8 to have a lower operational cost than scenario 7 by reducing the cost of imported energy from the grid, as shown in Table 26.

Case study 9 allows the MG to export energy to the main grid. In this case, the minimum cost is obtained mainly by managing the import/export power with the main grid optimally, exporting the excess of renewable energy during midday instead of storing it and charging the battery during the night. Even with a BESS available and the capacity to sell energy to the main grid, the EMS doesn't use it for arbitrage. This is due to the high cost of using the BESS (0.253 [$/kWh]), making arbitrage with the BESS undesirable. The BESS is instead used to supply its internal load during peak hours just enough to maximize the BESS operation time.

Scenario 10 presents the effect of not including calendar degradation on the mathematical model. The BESS is not used in its daily operation and at the ends of its lifetime (20 years), the BESS will need to be replaced with little to no use. There is also an increase in the cost of 63 [$] (or 3.3%) due to an increase in imported energy during peak hours compared to scenario 9, which made use of the BESS to reduce the amount of imported energy during peak hours. This scenario study shows the importance of including calendar lifetime for BESS on grid-connected MG operation.

Table 26: Summary of case study 7-10

	Op. Cost [$]	Grid net cost [$]	BESS cost [$]	BESS eff. [%]	BESS disch. [kWh]	BESS life [years]	Summary
Scenario 7	$ 1,998	$ 1,656	$ 343	77%	484	8	LA BESS
Scenario 8	$ 1,921	$ 1,579	$ 343	90%	1,230	20	Na BESS
Scenario 9	$ 1,881	$ 1,541	$ 343	90%	1,218	20	+ Arbitrage
Scenario 10	$ 1,944	$ 1,604	$ 343	-	0	20	No Cal. Deg.

In scenarios 11 the MG can provide the main grid with active power support in case of emergency. Without almost any change to its operation, the MG is able to provide 5.4 and 0.85 [MW] in up and down reserve. This allows the grid to make the most of the already existing and unused flexibility in the MG, while the MG received economic benefits, as can be seen in Table 27.

The DR options in scenario 12 adds the ability to shift the consumption of customers from peak to off-peak hours, which make the operation of the MG less expensive and more efficient, reducing the cost of imported energy by 3.8%. This also allows the MG to provide slightly more reserve than in scenario 11.

Comparing case study 4 and 12, we can see that the impact of DR is smaller in the connected scenario than in the islanded scenario.

Table 27: Summary of case study 11-12

	Op. Cost [$]	Grid net cost [$]	Reserve [$]	Summary
Scenario 11	$ 1,866	$ 1,541	14.8	Power support + DR
Scenario 12	$ 1,794	$ 1,485	30.5	

Scenarios 7-12 have presented a MILP model applied on CIGRE benchmark MG with different battery technologies, with and without DR, capable or not of selling energy and offering power support. These simulations show how both the grid and the MG can benefit by making use of the already existing flexible MG equipment.

4.3 CASE STUDY: SANTA RITA JAIL

In Dublin, California, lays Santa Rita Jail (37° 43' 4" N, 121° 53' 17" W). This jail houses over 4,000 inmates. Over the past decade Alameda County, which operates the Jail, has installed over the years a series of DER units to reduce energy consumption at the site.

California is known for having a history of electrical problems and consequent progress. Reliability in the Jail was a major concern, particularly having enough energy to maintain full service during the break between a blackout beginning and the backup diesel generators reaching full power, typically a few minutes.

To solve this, a project in association with Berkeley Labs turned the jail and it’s DER into a Microgrid in 2012. This MG was designed and is currently attended by Berkeley Lab [**106**].

4.3.1 MICROGRID TOPOLOGY

The Single Line Diagram of this 2-bus MG is presented in Figure 58. The DER units available to the MG are: two diesel generators, a large PV plant, a molten carbonate fuel cell, and a lithium iron BESS. Based on the available information (see [**106**]), the maximum power of the Diesel, PV plant, fuel cell and BESS is presented in Table 28. In the case of the BESS unit, the storage capacity is also included. Thanks to its BESS and a switching system, this MG can island and reconnect at will.

Table 28: Summary table of the Santa Rita Jail MG DER units

DER		Units
Genset 1	1,200	[kW]
Genset 2	1,200	[kW]
Wind	11.5	[kW]
PV	1,500	[kW]
Bess Ion-Li	2,000	[kW]
	4,000	[kWh]
Fuel cell	1,000	[kW]

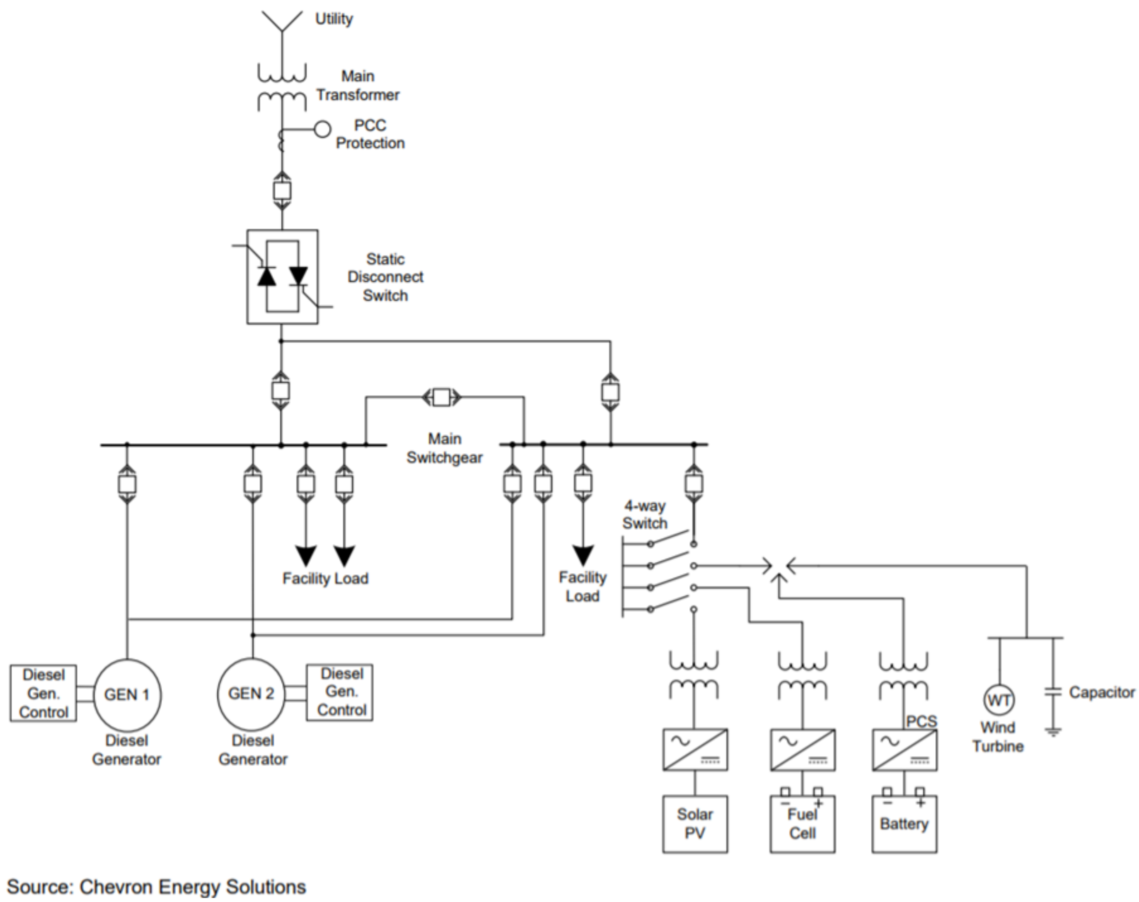

Figure 58: Santa Rita Jail MG Single Line Diagram. [**107**]

4.3.2 LOAD PROFILE

SRJ is considered one of the most energy efficient jails in the U.S and has had a fairly flat load during the day with an electricity peak demand of about 3.0 MW. The electrical consumption peaks during the months of summer are presented in Figure 59, obtained from Berkley Lab 2013 report [**107**].

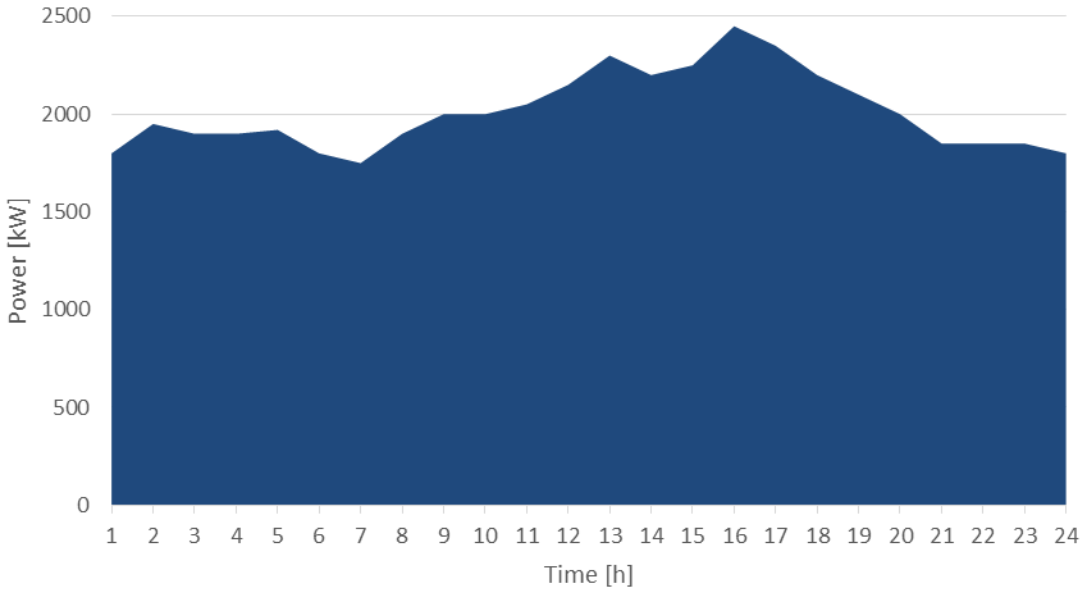

Figure 59: Load Profile for the Santa Rita Jail MG in summer.

4.3.3 RENEWABLE RESOURCES

While the PV plan installed has a nominal maximum power of 1,500 [kW], historical data has shown that the PV plant doesn't generate power near its nominal value. The current solar PV system is operating close to half of its installed rating. Historical data shows that typically during summer the maximum peak reaches 500 [kW] during summer. Based on reported PV production from SRJ, the profile shown in Figure 60 is used on the simulations. The 11.5 [kW] Wind turbine will be ignored for the simulations.

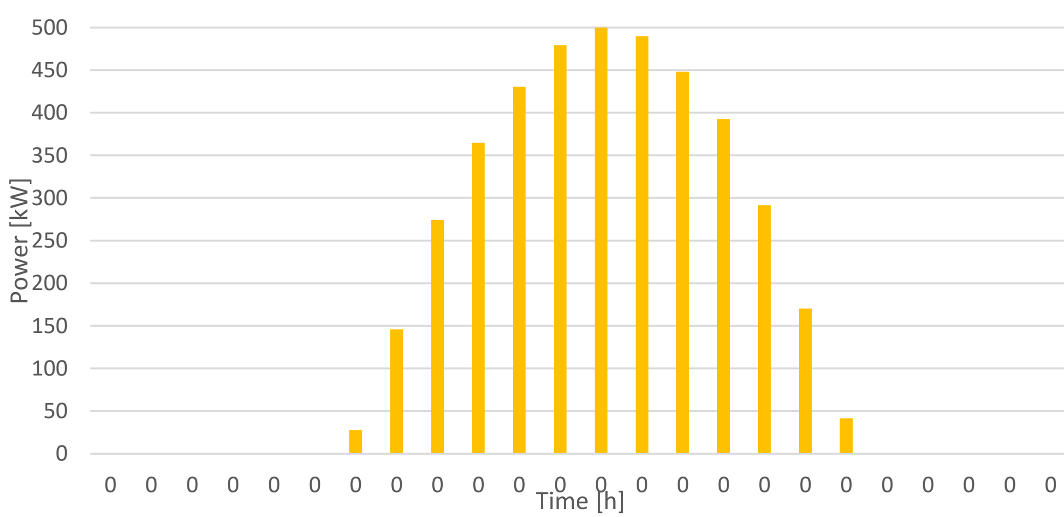

Figure 60: Summer PV generation for Santa Rita Jail MG.

4.3.4 UNIT PARAMETERS

The diesel generator operating cost parameters are obtained by assuming a diesel price of 1 [USD/l]. The cost of natural gas is assumed as 0.474 [USD/Thm] based on reports from the Santa Rita Jail operation.

While the nominal maximum power of the Fuel cell is 1,000 [kW], real operation has shown it can generate a maximum of 800 [kW], which will be used for the simulations.

The maximum & minimum power, variable consumption (alpha) and static consumption (beta) of the operating Gensets and Fuel cell are presented in Table 29

Table 29: Genset parameters for Santa Rita Jail.

Unit #	Pmax [kW]	Pmin [kW]	alpha [$/Wh]	beta [$]	Startup [$]
Diesel 1	960	300	0.2	20	10
Diesel 2	960	300	0.2	20	10
Fuel cell	800	0	0.07234	0	0

Based on reports of the Lithium-ion Iron-Phosphate battery system [**108**], the parameters for battery aging and Peukert's effect are obtained and presented in Table 30 and Table 31. This battery has reported average round-trip efficiency of 88-95%, a throughput capacity of up to 3,600,000 [kWh] during its useful life and up to 8 years of shelf life. The cost of this battery was estimated at 7,000,000 [USD] based on the 2014 Energy Storage Technologies review done by Sabihuddin et al. [**109**]

Table 30: SoC vs λ_v for Santa Rita Jail Li BESS.

SoCmax	SoCmin	λ_v
1	0.8	1
0.8	0.6	2
0.6	0.4	3
0.4	0.2	6

Table 31: Pb vs δ_w for Santa Rita Jail Li BESS

Pbmax	Pbmin	δ_w [Ah]
0	500	3,957.005

500	1,000	3,864.222
1,000	1,500	3,772.376
1,500	2,000	3,681.468

4.3.5 AVAILABLE SERVICES

In the case of SRJ, there are 4 possible services that such a MG can consider. These are: arbitrage, via net metering, the ability to reduce consumption on demand during peak hours, known as capacity bidding, ensuring islanded operation reliability considering the minimum start time of the backup generators, and the ability to shave the maximum peak power (peak shaving).

The Pacific Gas and Electricity Company (PG&E) is the ISO for Santa Rita Jail, and it has a time of use Electricity tariff as indicated in Table 32.

Table 32: Time of Use Electricity Tariff at Santa Rita Jail. Source: PG&E E-20 Industrial Tariff

Period		Power [$/kW]	Energy [$/kWh]	Duration
Summer May-Oct	On-peak	11.04	0.14040	12:00-18:00
	Mid-peak	2.59	0.09807	8:30-12:00,18:00-21:30
	Off-peak	0.00	0.07992	21:30-12:00
	Monthly-max	7.45	-	
Winter Nov-Apr	Mid-peak	0.82	0.08585	8:30-21:30
	Off-peak	0.00	0.07664	21:30-8:30
	Monthly-max	7.45	-	

As indicated in [**110**], the operator of a centralized microgrid has the potential to deliver services to the utility when the microgrid has excess supply and/or is economically advantaged for doing so. Consider current California regulation, the following option is the best option for selling energy to the grid:

- Net Energy Metering: Limited to 1MW of capacity, with a further utility total capacity cap, net metering credits the exporting generator for power delivered to the utility grid at retail rates .6.

PG&E also has a CB program in effect, which has a monthly incentive to reduce energy by a previously agreed amount with Day-Ahead and Day-Of options. It includes two incentives, a Capacity payment that PG&E pays monthly for the commitment and an energy payment for an event curtailment. The available alternatives and payment for CB are shown in Table 33 and Table 34.

Table 33: Alternatives for Capacity Bidding Source: PG&E Capacity Bidding Program

Product	Minimum Duration per Event	Maximum Duration per Event	Maximum Events Per Day Hours Per Operating Month	Maximum Events Per Day
1-4 Hour	1 Hour	4 Hours	30	1
2-6 Hour	2 Hours	6 Hours	30	1
4-8 Hour	4 Hours	8 Hours	30	1

Table 34: Capacity bidding price by month Source: PG&E Capacity Bidding Program

Aggregators in Day-Ahead Option

Product	May	June	July	August	September	October
1-4 Hour	$3.04/kW	$3.71/kW	$15.60/kW	$21.57/kW	$13.30/kW	$2.17/kW
2-6 Hour	$3.04/kW	$3.71/kW	$15.60/kW	$21.57/kW	$13.30/kW	$2.17/kW
4-8 Hour	$3.04/kW	$3.71/kW	$15.60/kW	$21.57/kW	$13.30/kW	$2.17/kW

Aggregators in Day-Of Option

Product	May	June	July	August	September	October
1-4 Hour	$3.50/kW	$4.27/kW	$17.94/kW	$24.81/kW	$15.30/kW	$2.50/kW
2-6 Hour	$3.50/kW	$4.27/kW	$17.94/kW	$24.81/kW	$15.30/kW	$2.50/kW
4-8 Hour	$3.50/kW	$4.27/kW	$17.94/kW	$24.81/kW	$15.30/kW	$2.50/kW

For the simulation, we will consider the 1-4 hours day-of option.

As a Jail, the islanded operation reliability is of critical importance and the value of load loss used for islanded operation will be 49 [$/kWh] based on Berkley National Lab review [**111**]. It has been reported that the diesel generators take several minutes to start, so having enough capacity during the transition from grid operation to the operation of the diesel generators has to be considered.

There is information about historical blackouts from 2002 to 2006 in the SRJ project final report [**107**], summarized in

Table 35. This information is used to obtain the statistics of unplanned islanded operation. Table 36 presents the probability of an outage happening in the SRJ Feeder and its duration in 20 minute periods.

Table 35: Santa Rita Jail Distribution Feeder Five-Year Outage History

Date	Minutes Out of Service
12/16/2002	287
10/16/2004	80
10/20/2005	3
12/13/2005	Momentary
01/26/2006	56
01/29/2006	Momentary
03/21/2006	Momentary
03/26/2006	26
09/08/2006	6
10/09/2006	Momentary
Five-Year Total	458

Table 36: Outage frequency for Santa Rita Jail Distribution Feeder

Frequency [%/day]	Duration [Periods]
0.3288%	1
0.0548%	2
0.0548%	3
0.0548%	4
0.0548%	15

4.3.6 Scenarios

Considering the previous information, there will be seven different scenarios for this case study, where we will explore more AS and MG reliability. The thirteenth scenario represents the connected MG, but without the capacity to neither offering any AS nor selling energy. The fourteenth scenario adds the possibility to sell energy and reduce emissions. The fifteenth scenario also includes peaks shaving. The three following scenarios, scenarios sixteenth, seventeenth and eighteenth explore the addition of capacity bidding service for the months of May, June and July respectively. The payment of this service changes in each month, so this will allow us to see the viability of offering this service for a MG under different conditions. Finally, scenario nineteenth will explore the change in operation of including outage reliability to the MG operation.

Thus the scenarios are:

13. Connected MG.
14. Connected MG, emission reduction & arbitrage.
15. Connected MG, emission reduction, arbitrage & peak shaving.
16. Connected MG, emission reduction, arbitrage, peak shaving & capacity bidding (May).
17. Connected MG, emission reduction, arbitrage, peak shaving & capacity bidding (June).
18. Connected MG, emission reduction, arbitrage, peak shaving & capacity bidding (July).
19. Connected MG, emission reduction, arbitrage, peak shaving & islanding reliability.

4.3.7 SCENARIO 13: CONNECTED MG.

Our thirteenth case study simulates the operation of the connected MG of SRJ, without offering any service and using Lithium based BESS.

Figure 61 presents the resulting operation of the SRJ MG. As can be seen in the figure, almost half the demand is supplied by a combination of the Fuel cell (19,200 [kWh]), the PV plant (4,056 [kWh]) and the BESS (3,107 [kWh]). The BESS mostly discharge during peak hours and charges during off-peak hours. The remaining load is supplied directly by the Grid (25,229 [kW]), with 3.271 [kWh] of that energy used to recharge the BESS during off-peak hours.

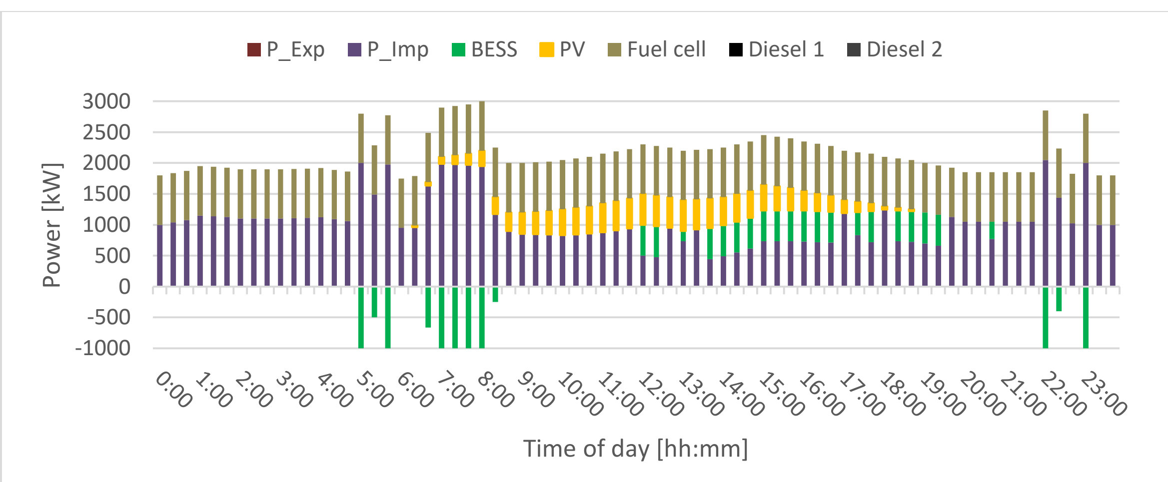

Figure 61: Operation for case study 13

Table 37 breaks down the daily operation for the different elements in the MG, including:

- Operational time, energy provided, fuel cost and average generation cost of the Fuel cell.
- Operational time, fuel used, fuel cost and average generation cost of the Diesel generator.
- The expected lifetime of the battery, the cost of usage, average discharged power, discharged energy through the day, usage cost and round trip efficiency.
- The daily energy and revenue from exporting energy to the grid
- The daily energy and cost from importing energy from the grid
- The amount of energy not supplied and the penalty associated.
- The peak power and associated payment.

We can see that the optimizer tries to minimize the usage of the BESS; using it just enough to ensure it will last for its shelf life (20 years). The BESS SoC is presented in Figure 62. As expected, there is no NSE present.

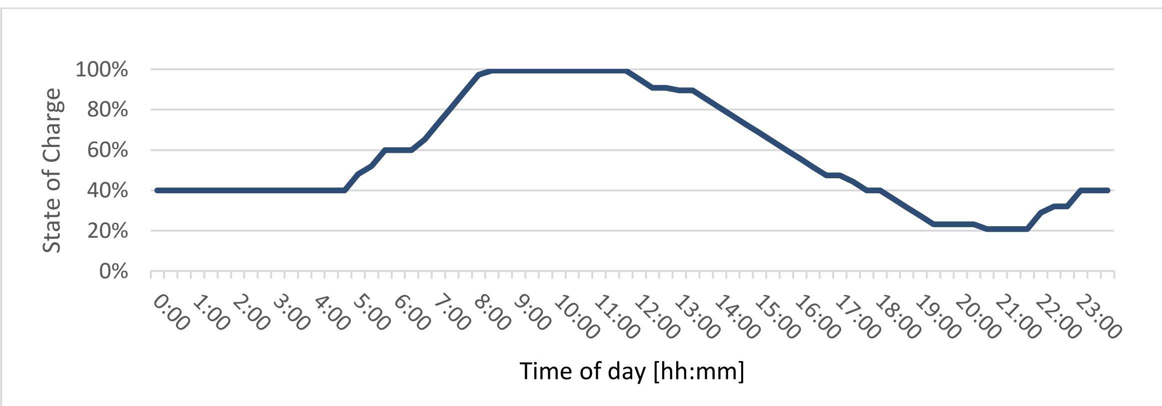

Figure 62: State of Charge for case study 13

Table 37: Operation Summary of all units for case study 13

Unit	Item	Value	Units
Fuel cell	Op. Time	24.0	[h]
	Energy	19,200	[kh]
	Fuel cost	1,389	[$]
	Gen cost	0.072	[$/kWh]
Diesel	Op. Time	0	[h]
	Fuel	0	[l]
	Fuel cost	0	[$]
	Gen cost	0	[$/kWh]

Battery	Ex. Lifetime	7,300	[days]
		20	[years]
	Usage value	951.9	[$]
	Disch. Power	466	[kW]
	Disch. Energy	3,106.6	[kWh]
	Usage cost	0.291	[$/kWh]
	Rd. Trip Eff.	95%	[%]
Exp Grid	Energy	0	[kWh]
	Total Cost	0	[$]
	Av. Cost	0	[$/kWh]
Imp Grid	Energy	25,229	[kWh]
	Total Cost	2,524	[$]
	Av. Cost	0.100	[$/kWh]
NSE	Energy	0	[kWh]
	Cost	0	[$]
Peak	Power	2,050	[kW]
	Cost	509.43	[$]
Total cost		5,375.03	[$]

4.3.8 Scenario 14: Connected MG, emission reduction & arbitrage

Our fourteenth case study simulates the operation of the connected MG of SRJ, buying and selling energy from the Grid and considering emissions.

Figure 63 presents the operation of the connected SRJ MG. As can be seen in the graph, almost half the demand is supplied with the Fuel cell (19,200 [kWh], the PV plant (4,056 [kWh]) and the BESS (3,107 [kWh]) mostly on peak hours. The rest is supplied directly from the Grid (25,229 [kW]), with 3,271 [kWh] of that energy used to recharge the BESS during off-peak hours.

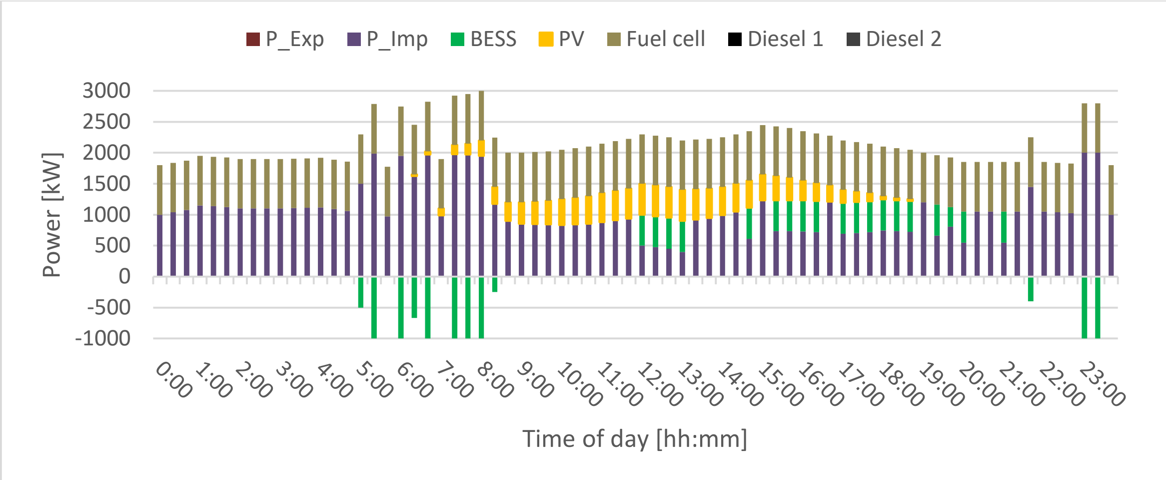

Figure 63: Operation for case study 14

Table 38 additionally included the emissions reduced by the MG and its associated payment. We can see that the optimizer tries to minimize the usage of the BESS, using it just enough to ensure it will last for its shelf life (20 years).

Table 38: Operation Summary of all units for case study 14

Unit	Item	Value	Units
Fuel cell	Op. Time	24	[h]
	Energy	19,200	[kWh]
	Fuel cost	1,389	[$]
	Gen cost	0.072	[$/kWh]
Diesel	Op. Time	0	[h]
	Fuel	0	[l]
	Fuel cost	0	[$]
	Gen cost	0	[$/kWh]
Battery	Ex. Lifetime	7,300	[days]
		20	[years]
	Usage value	951.9	[$]
	Disch. Power	466	[kW]
	Disch. Energy	3,106.	[kWh]
	Usage cost	0.291	[$/kWh]
	Rd. Trip Eff.	95%	[%]
Exp Grid	Energy	0	[kWh]
	Total Cost	0	[$]
	Av. Cost	0	[$/kWh]
Imp Grid	Energy	25,229	[kWh]
	Total Cost	2,524	[$]

	Av. Cost	0.1	[$/kWh]
NSE	Energy	0	[kWh]
	Cost	0	[$]
Peak	Power	2,000	[kW]
	Cost	497	[$]
Emissions	Revenue	0	[$]
	Energy	0	[kWh]
	Av. Cost	0	[$/kWh]
Total cost		5,362.2	[$]

4.3.9 Scenario 15: Connected MG, emission reduction, arbitrage & peak shaving

Our fifteenth case study simulates the operation of the connected MG of SRJ, offering the services of emission reduction, buying and selling energy, and peak shaving.

Figure 64 presents the operation of the connected SRJ MG. As can be seen in the graph, almost half the demand is supplied with the fuel cell (19,200 [kWh], the PV plant (4,056 [kWh]) and the BESS (2,934 [kWh]) mostly on peak hours. The rest is supplied directly from the Grid (25,220 [kW]), with 3,089 [kWh] of that energy used to recharge the BESS during off-peak hours.

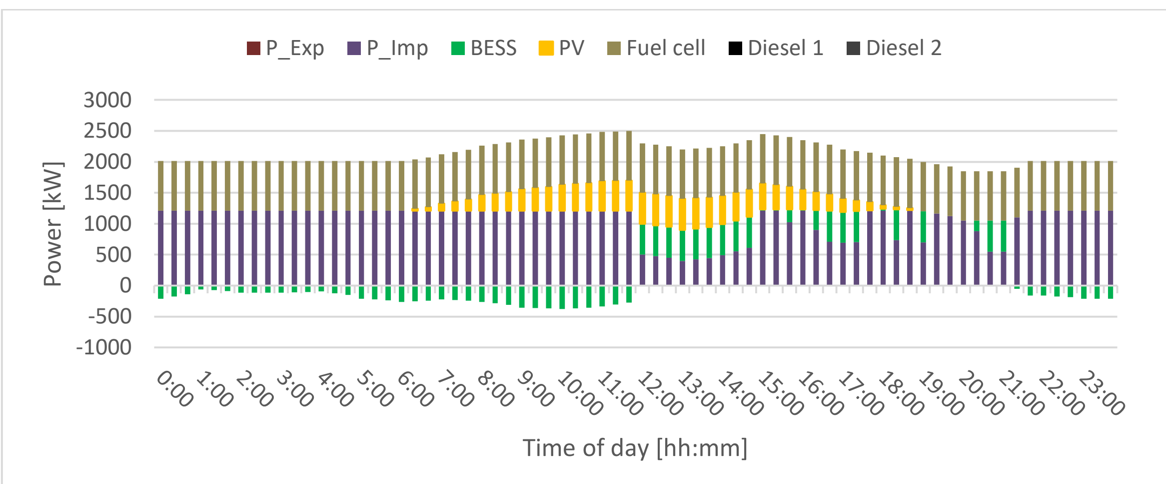

Figure 64: Operation for case study 15

Table 39 summarizes the MG operation. On it can be seen that the optimizer tries to minimize the usage of the BESS, using it just enough to ensure it will last for its shelf life (20 years). We can also see that the maximum imported power has been reduced from 2,000 [kW] to only 1,212.67 [kW], which helps reduce the payment of power by 8,700 [$/month] or 190 [$/day].

Table 39: Operation Summary of all units for case study 15

Unit	Item	Value	Units
Fuel cell	Op. Time	24	[h]
	Energy	19,200	[kWh]
	Fuel cost	1,389	[$]
	Gen cost	0.072	[$/kWh]
Diesel	Op. Time	0	[h]
	Fuel	0	[l]
	Fuel cost	0	[$]
	Gen cost	0	[$/kWh]
Battery	Ex. Lifetime	7,300	[days]
		20	[years]
	Usage value	958.9	[$]
	Disch. Power	352	[kW]
	Disch. Energy	2,933.7	[kWh]
	Usage cost	0.31	[$/kWh]
	Rd. Trip Eff.	95%	[%]
Exp Grid	Energy	0	[kWh]
	Total Cost	0	[$]
	Av. Cost	0	[$/kWh]
Imp Grid	Energy	25,220	[kWh]
	Total Cost	2,556	[$]
	Av. Cost	0.101	[$/kWh]
NSE	Energy	0	[kWh]
	Cost	0	[$]
Peak	Power	1,212.67	[kW]
	Cost	301.15	[$]
Emissions	Revenue	0	[$]
	Energy	0	[kWh]
	Av. Cost	0	[$/kWh]
Total cost		5,204.71	[$]

4.3.10 SCENARIO 16: CONNECTED MG, EMISSION REDUCTION, ARBITRAGE, PEAK SHAVING & CAPACITY BIDDING (MAY)

For this simulation, in addition to all previous services, the MG will offer CB on demand, reducing its power import from the grid for up to 4 hours, on the month of May.

For this simulation, we will assume there is a 6% chance the service is required at the beginning of peak hour for 1 hour, another 6% chance of it happening at the mid of peak hour and a 6% chance of it happening on the later hours of peak hour. The possibility of this happening for 2 hours will be considered as half the chance of it happening for 1 hour, a quarter for 3 hours and an eight of a chance for 4 hours. Thus the 12 slaves generated are presented in Table 40.

Table 40: Slaves for case study 16

	Duration [hrs]	Initial Period	Final Period	Frequency
Slave 1	1	37	39	6%
Slave 2		45	47	6%
Slave 3		52	54	6%
Slave 4	2	37	42	3%
Slave 5		43	48	3%
Slave 6		49	54	3%
Slave 7	3	37	45	1.5%
Slave 8		42	50	1.5%
Slave 9		46	54	1.5%
Slave 10	4	37	48	0.75%
Slave 11		40	51	0.75%
Slave 12		43	54	0.75%

Figure 65 presents the operation of the connected SRJ MG. As can be seen in the graph, almost half the demand is supplied with the Fuel cell (19,200 [kWh], the PV plant (4,056 [kWh]) and the BESS (2,374 [kWh]) mostly on peak hours. The rest is supplied directly from the grid (25,190 [kW]), with 2.500 [kWh] of that energy used to recharge the BESS during off-peak hours.

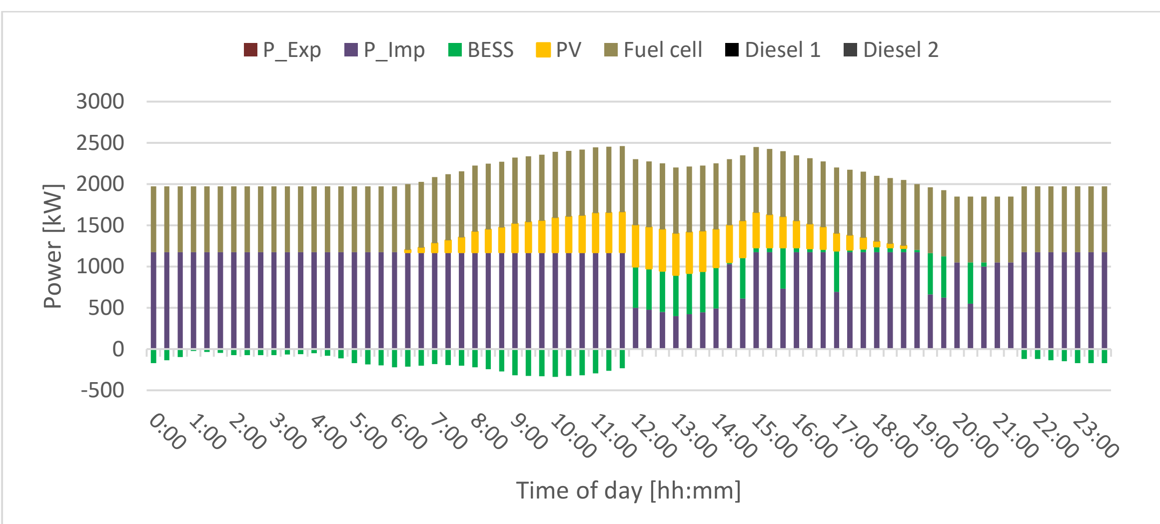

Figure 65: Operation for case study 16, Master problem Iteration 6

Table 41 now includes the power reserved for CB and its associated revenue. We can see that the optimizer tries to minimize the usage of the BESS, using it just enough to ensure it will last for its shelf life (20 years). As expected, there is no NSE present.

Table 41: Operation Summary of all units for case study 16

Unit	Item	Value	Units
Fuelcell	Op. Time	24	[h]
	Energy	19,200	[kWh]
	Fuel cost	1,389	[$]
	Gen cost	0.072	[$/kWh]
Diesel	Op. Time	0	[h]
	Fuel	0	[l]
	Fuel cost	0	[$]
	Gen cost	0	[$/kWh]
Battery	Ex. Lifetime	7,300	[days]
		20	[years]
	Usage value	958.9	[$]
	Disch. Power	274	
	Disch. Energy	2,374.2	[kWh]
	Usage cost	0.384	[$/kWh]
	Rd. Trip Eff.	95%	[%]
Exp Grid	Energy	0	[kWh]
	Total Cost	0	[$]
	Av. Cost	0	[$/kWh]
Imp Grid	Energy	25,190	[kWh]
	Total Cost	2,585	[$]
	Av. Cost	0.103	[$/kWh]
NSE	Energy	0	[kWh]
	Cost	0	[$]
Arbitrage	Revenue	(2,585)	[$]
Peak	Power	1,171.77	[kW]
	Cost	292.99	[$]
Emissions	Revenue	0	[$]
	Energy	0	[kWh]
	Av. Cost	0.00396	[$/kWh]
Capacity Bid	Power	7.23	[kW]
	Revenue	1	[$]
Total cost		5,222.85	[$]

Table 42 shows the offered CB for each iteration and the expected operational cost of the MG without including the additional cost of having to reduce electrical import (O.F. Master). In each iteration 12 slaves are generated, each one simulating the operational cost of complying with CB requirements by IESO under different scenarios. The objective function of the 12 slaves (O.F. Slave x) is then presented. The Slave Penalty indicator shows the increase in operational cost compared with the base operation, including the probability of each possible scenario happening according to Table 40. The Net revenue combines the revenue obtained from offering CB with the penalty cost of the slaves. A positive value means the net result is positive for the MG and a negative value indicates offering CB affect the MG economical balance negatively.

In this scenario, offering CB has a negative value for all iterations and in each consecutive iteration the amount of offered CB is being reduced, approaching a solution more and more similar to case study 14.

Table 42: Slaves for case study 16

	Iteration 1	Iteration 2	Iteration 3	Iteration 4	Iteration 5
O.F. Master	$ 5,322.8	$ 5,343.6	$ 5,353.3	$ 5,359.8	$ 5,362.9
Cap. Bid. [kW]	400	340.682	166.565	55.0207	7.23432
O.F. Slave 1	$ 5,372.4	$ 5,384.1	$ 5,380.2	$ 5,382.9	$ 5,369.4
O.F. Slave 2	$ 5,370.3	$ 5,383.9	$ 5,381.8	$ 5,384.2	$ 5,369.7
O.F. Slave 3	$ 5,373.4	$ 5,386.8	$ 5,383.5	$ 5,385.2	$ 5,369.8
O.F. Slave 4	$ 5,409.2	$ 5,418.5	$ 5,398.2	$ 5,386.8	$ 5,376.0
O.F. Slave 5	$ 5,409.5	$ 5,417.3	$ 5,397.5	$ 5,386.4	$ 5,376.0
O.F. Slave 6	$ 5,413.2	$ 5,419.4	$ 5,397.3	$ 5,386.1	$ 5,376.0
O.F. Slave 7	$ 5,449.6	$ 5,452.7	$ 5,416.5	$ 5,390.4	$ 5,382.2
O.F. Slave 8	$ 5,449.2	$ 5,448.6	$ 5,415.0	$ 5,390.1	$ 5,382.2
O.F. Slave 9	$ 5,453.0	$ 5,451.4	$ 5,416.6	$ 5,389.7	$ 5,382.2
O.F. Slave 10	$ 5,488.8	$ 5,481.6	$ 5,430.1	$ 5,394.7	$ 5,386.6

O.F. Slave 11	$ 5,489.1	$ 5,478.4	$ 5,429.2	$ 5,394.2	$ 5,386.6
O.F. Slave 12	$ 5,492.1	$ 5,478.7	$ 5,428.6	$ 5,393.8	$ 5,386.6
Slave penalty	$ 43.83	$ 36.76	$ 22.77	$ 14.85	$ 6.30
Net revenue	$ (3.29)	$ (17.07)	$ (12.79)	$ (11.34)	$ (5.95)

Figure 66 shows the operation of the 12th slave in the first iteration (CB=400). As can be seen, to compensate for the reduction of imported power during this period, a diesel generator is used. As can be seen in

Table 42, this increases considerably the operation cost, by 169.3 [$], if such a reduction in imported power is required by IESO. Figure 67 shows the fourth iteration of slave 12 when the CB offering has been reduced to only 55 [kW]. The diesel Generator operation has been considerably reduced to only 20 minutes instead of almost 2 hours. This shows that at the prices offered in may (3.5 [$/kW]), CB is not a convenient service to offer.

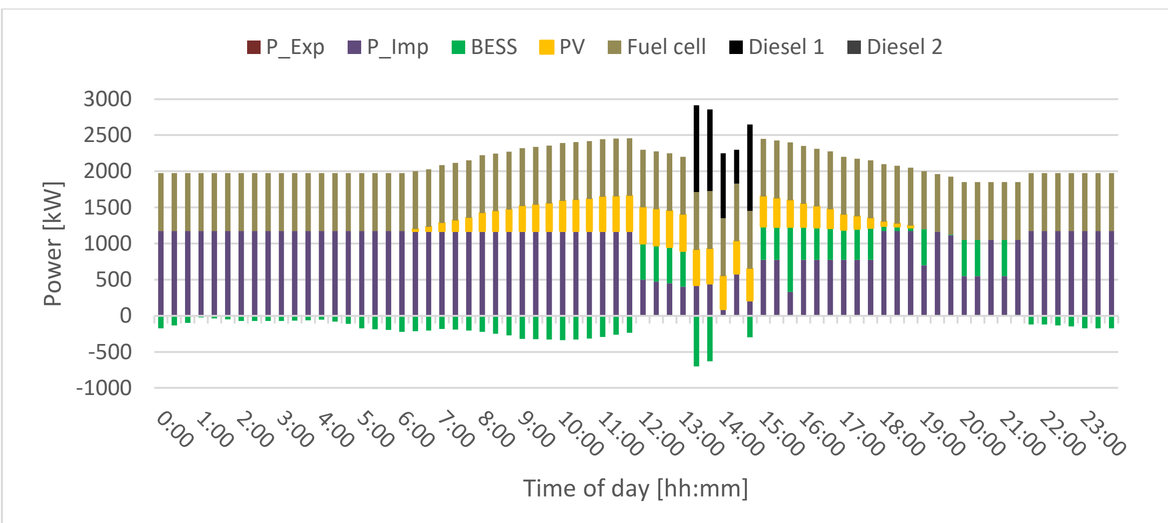

Figure 66: Operation for case study 16, Slave 12, Iteration 1

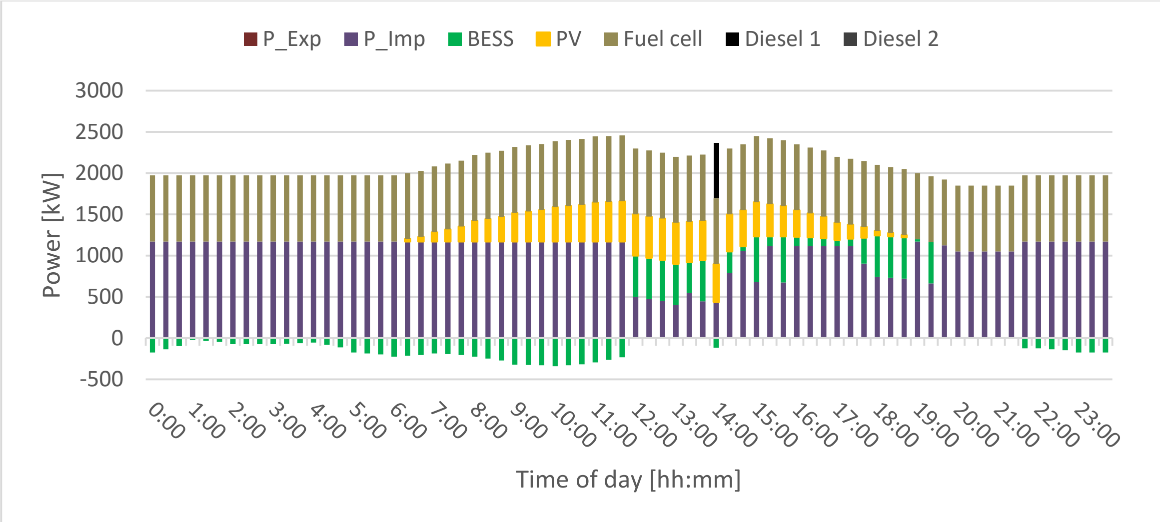

Figure 67: Operation for case study 16, Slave 12, Iteration 4

4.3.11 Scenario 17: Connected MG, emission reduction, arbitrage, peak shaving & capacity bidding (June)

For this simulation, we will include offering CB on demand for up to 4 hours, during the month of June. The 12 slaves generated are the same ones as in Case Study 16, presented in Table 40.

Figure 68 presents the operation of the connected SRJ MG offering CB. As can be seen in the graph, almost half the demand is supplied with the Fuel cell (19,200 [kWh], the PV plant (4,056 [kWh]) and the BESS (3,107 [kWh]) mostly on peak hours. The rest is supplied directly from the Grid (25,229 [kW]), with 3.271 [kWh] of that energy used to recharge the BESS during off-peak hours.

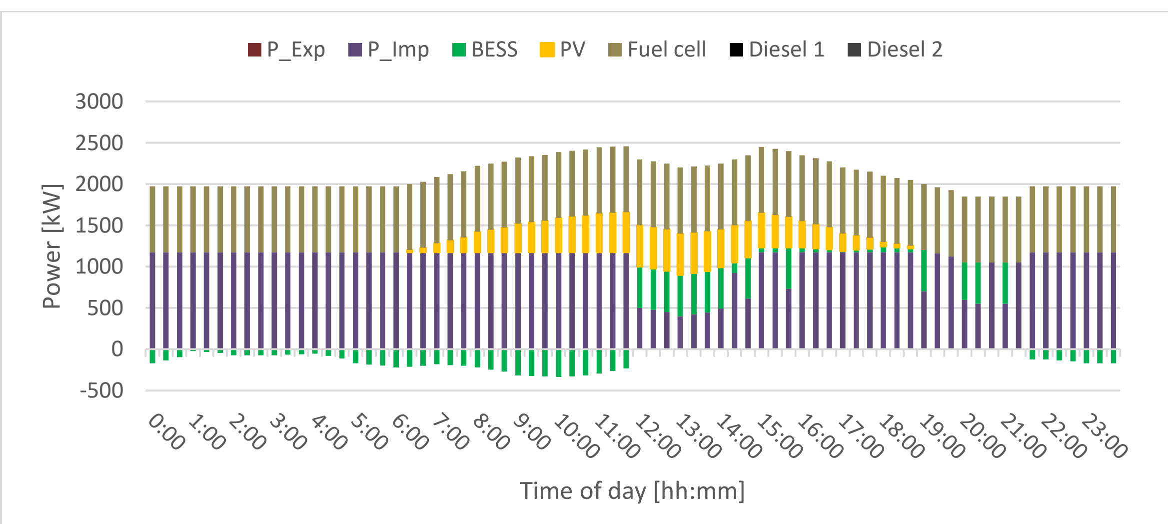

Figure 68: Operation for case study 17

Looking at Table 43, we can see that the optimizer tries to minimize the usage of the BESS; using it just enough to ensure it will last for its shelf life (20 years). As expected, there is no NSE present.

Table 43: Operation Summary of all units for case study 17

Unit	Item	Value	Units
Fuel cell	Op. Time	24	[h]
	Energy	19,200	[kWh]
	Fuel cost	1,389	[$]
	Gen cost	0.072	[$/kWh]
Diesel	Op. Time	0	[h]
	Fuel	0	[l]
	Fuel cost	0	[$]
	Gen cost	0	[$/kWh]
Battery	Ex. Lifetime	7,300	[days]
		20	[years]
	Usage value	958.9	[$]
	Disch. Power	466	[kW]
	Disch. Energy	2,374.2	[kWh]
	Usage cost	0.384	[$/kWh]
	Rd. Trip Eff.	95%	[%]
Exp Grid	Energy	0	[kWh]
	Total Cost	0	[$]
	Av. Cost	0	[$/kWh]
Imp Grid	Energy	25,190	[kWh]
	Total Cost	2,584	[$]
	Av. Cost	0.103	[$/kWh]
NSE	Energy	0	[kWh]
	Cost	0	[$]
Peak	Power	1,172.81	[kW]
	Cost	291.25	[$]
Emissions	Revenue	0	[$]
	Energy	0	[kWh]
	Av. Cost	0	[$/kWh]
Capacity Bid	Power	400	[kW]
	Revenue	49	[$]
Total cost		5,222.11	[$]

Similar to the previous Case Study, Table 44 shows the master O.F., the offered CB for each Iteration, the expected operational cost of the MG without CB and the 12 slaves operational cost of complying with the required CB. The Net revenue combines the revenue obtained from offering CB with the penalty cost of the slaves.

In this scenario, offering CB has a positive value in each iteration, thus the amount of offered CB is kept maximized.

Table 44: Slave results for case study 17

	Iteration 1	Iteration 2	Iteration 3
OF Master	$ 5,313.8	$ 5,313.8	$ 5,313.8
Cap. Bid. [kW]	400	400	400
OF Slave 1	$ 5,363.4	$ 5,378.7	$ 5,385.5
OF Slave 2	$ 5,360.5	$ 5,377.4	$ 5,383.4
OF Slave 3	$ 5,362.9	$ 5,381.1	$ 5,386.0
OF Slave 4	$ 5,397.7	$ 5,415.7	$ 5,420.4
OF Slave 5	$ 5,397.2	$ 5,413.0	$ 5,416.9
OF Slave 6	$ 5,400.4	$ 5,416.9	$ 5,420.1
OF Slave 7	$ 5,436.3	$ 5,452.7	$ 5,456.0
OF Slave 8	$ 5,435.3	$ 5,446.6	$ 5,449.4
OF Slave 9	$ 5,438.9	$ 5,452.5	$ 5,455.0
OF Slave 10	$ 5,474.5	$ 5,486.1	$ 5,488.3
OF Slave 11	$ 5,474.4	$ 5,482.2	$ 5,484.2
OF Slave 12	$ 5,477.3	$ 5,483.6	$ 5,485.7
Slave penalty	$ 42.81	$ 42.51	$ 40.79
Net revenue	$ 6.66	$ 6.96	$ 8.68

Figure 69 shows the operation of the 1st slave on the last iteration (CB=400). In this slave, the diesel generator has to provide 404 [kWh] between 12:00-13:00. Slave 6 on the other hand, see Figure 70, has to provide 816 [kWh] between 16:00-17:00. Two examples of the most severe reductions, slave 10 and 12, can be seen in Figure 71 and Figure 72. These are 4 hours where the MG basically can’t import power from the Grid. To deal with this problem, the BESS and Diesel Generator are used in conjunction. For these situations, the Genset and BESS have to generate 1,630 [kWh] and 1,645 [kWh] respectively. Thus, offering the maximum CB possible (400 [kW]) is a profitable enough option for the MG.

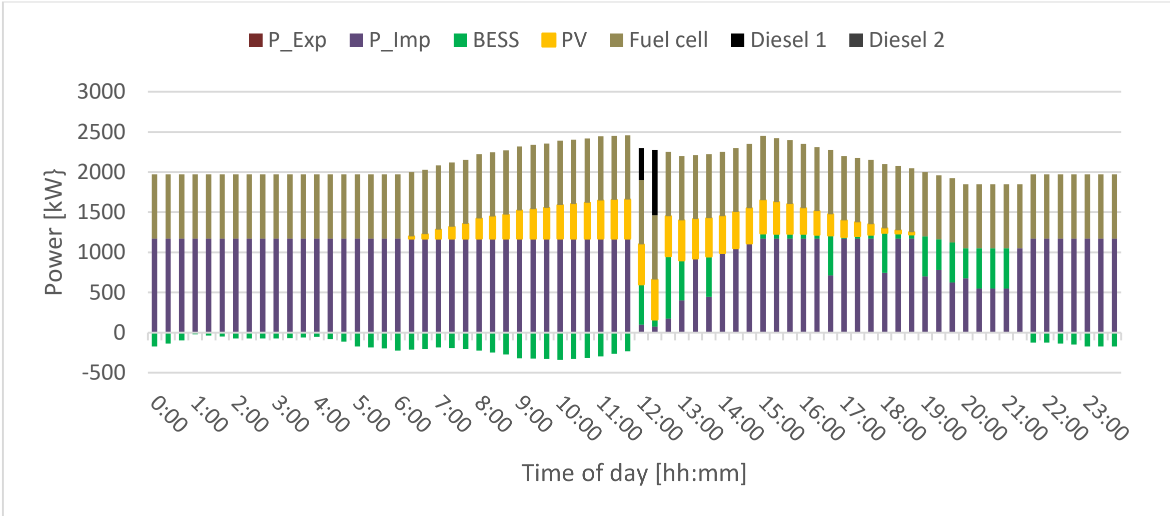

Figure 69: Operation for case study 17, Slave 1, Iteration 3

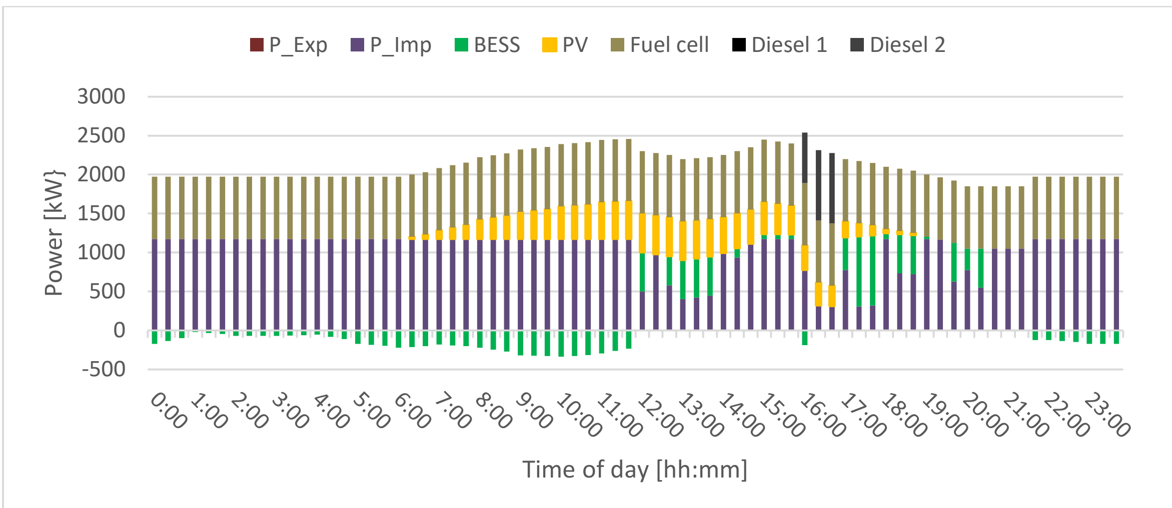

Figure 70: Operation for case study 17, Slave 6, Iteration 3

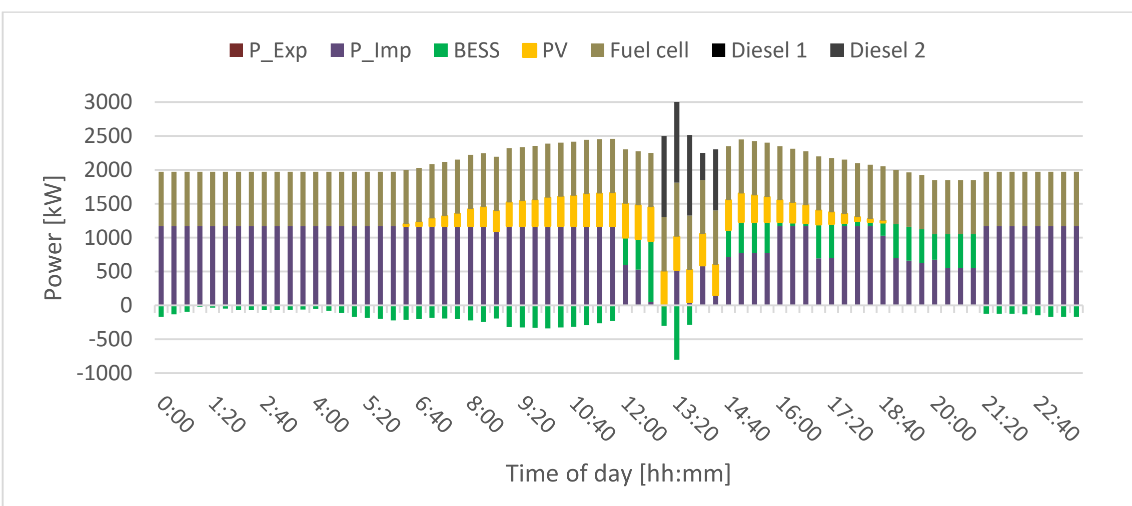

Figure 71: Operation for case study 17, Slave 10, Iteration 3

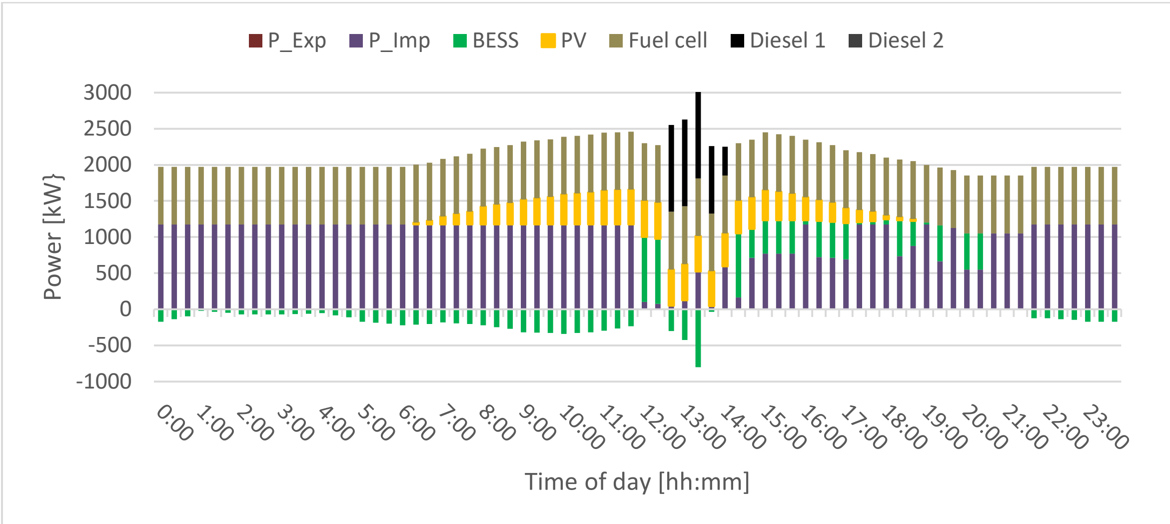

Figure 72: Operation for case study 17, Slave 12, Iteration 3

4.3.12 Scenario 18: Connected MG, emission reduction, arbitrage, peak shaving & capacity bidding (July)

For this simulation, we will include offering CB during the month of July. The 12 slaves generated are the same ones as in Case Study 17, presented in Table 40.

Figure 73 presents the operation of the connected SRJ MG offering CB, which is pretty much identical to Case study 16. Almost half the demand is supplied with the fuel cell (19,200 [kWh], the PV plant (4,056 [kWh]) and the BESS (2,934 [kWh]). The BESS mostly provides energy during peak hours. The rest is supplied directly from the grid (25,220 [kW]), with 3.098 [kWh] of that energy used to recharge the BESS during off-peak hours.

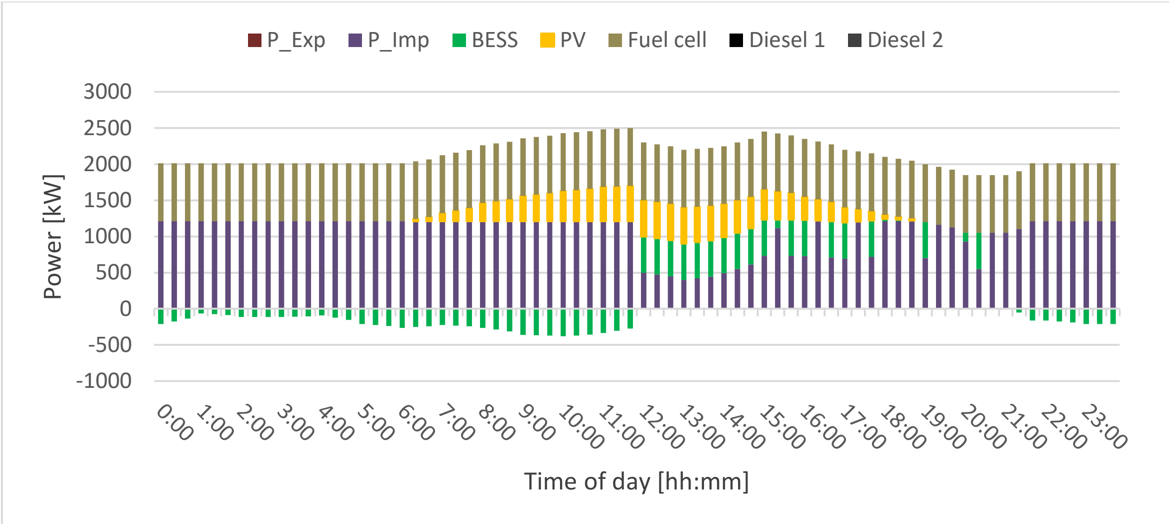

Figure 73: Operation for case study 18

Looking at Table 45 we can see that the optimizer tries to minimize the usage of the BESS, using it just enough to ensure it will last for its shelf life (20 years). The MG also offers as much CB as possible, 400 [kW] in this scenario. As expected, there is no NSE present.

Table 45: Operation Summary of all units for case study 18

Unit	Item	Value	Units
Fuel cell	Op. Time	24	[h]
	Energy	19,200	[kWh]
	Fuel cost	1,389	[$]
	Gen cost	0.072	[$/kWh]
Diesel	Op. Time	0	[h]
	Fuel	0	[l]
	Fuel cost	0	[$]
	Gen cost	0	[$/kWh]
Battery	Ex. Lifetime	7,300	[days]
		20	[years]
	Usage value	958.9	[$]
	Disch. Power	383	[kW]
	Disch. Energy	2,933.7	[kWh]
	Usage cost	0.310	[$/kWh]
	Rd. Trip Eff.	95%	[%]
Exp Grid	Energy	0	[kWh]
	Total Cost	0	[$]
	Av. Cost	0	[$/kWh]
Imp Grid	Energy	25,220	[kWh]

	Total Cost	2,556	[$]
	Av. Cost	0.101	[$/kWh]
NSE	Energy	0	[kWh]
	Cost	0	[$]
Peak	Power	1,212.67	[kW]
	Cost	301.15	[$]
Emissions	Revenue	0	[$]
	Energy	0	[kWh]
	Av. Cost	0	[$/kWh]
Capacity Bid	Power	400	[kW]
	Revenue	208	[$]
Total cost		4,996.71	[$]

4.3.13 SCENARIO 19: CONNECTED MG, EMISSION REDUCTION, ARBITRAGE, PEAK SHAVING & ISLANDING RELIABILITY

For this last simulation, reliability will be included. Using the 5 outage durations obtained in Table 36 and evaluating outages at 1:00, 7:00, 13:00 and 19:00, twenty slaves will be generated. The ensuing slaves are presented in Table 46, showing the combination of time of failure, duration and frequency that generates them. For this simulation we will assume only one diesel generator is available, considering an N-1 situation.

Table 46: Slaves for case study 19

	Time of failure	Duration [minutes]	Frequency
Slave 1	1:00	20	0.329%
Slave 2		40	0.055%
Slave 3		60	0.055%
Slave 4		80	0.055%
Slave 5		300	0.055%
Slave 6	7:00	20	0.329%
Slave 7		40	0.055%
Slave 8		60	0.055%
Slave 9		80	0.055%
Slave 10		300	0.055%
Slave 11	13:00	20	0.329%
Slave 12		40	0.055%
Slave 13		60	0.055%

Slave 14		80	0.055%
Slave 15		300	0.055%
Slave 16	19:00	20	0.329%
Slave 17		40	0.055%
Slave 18		60	0.055%
Slave 19		80	0.055%
Slave 20		300	0.055%

The resulting operation of the first Iteration is presented in Figure 74. This first iteration is identical to the one obtained on Case Study 14, with the only difference being the inclusion of a reliability cost penalty (72.64 [USD]) from the slaves, as can be seen on Table 47.

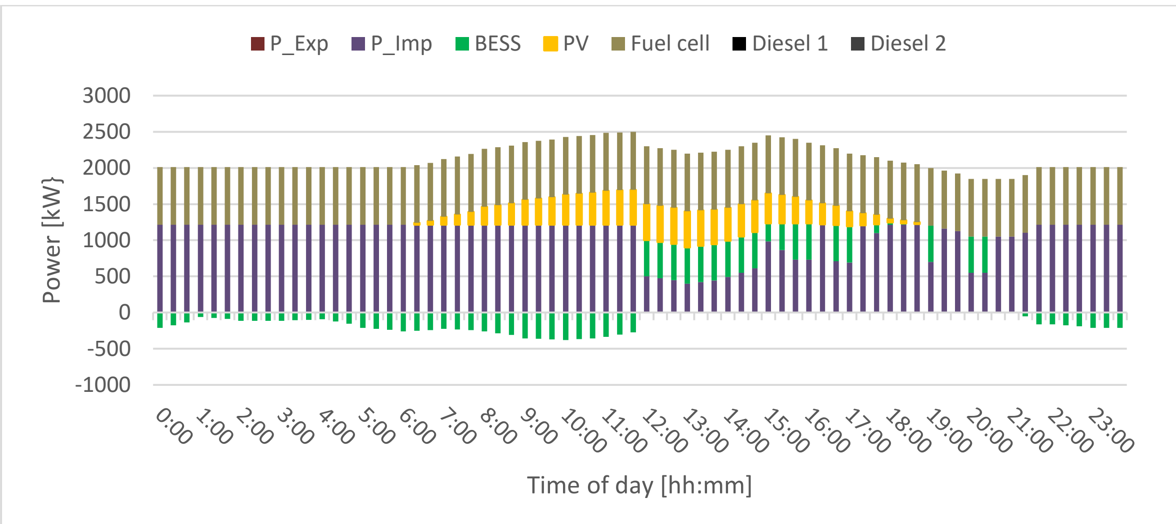

Figure 74: Operation for case study 19, Iteration 1

The operation of the third Iteration is presented in Figure 75. Compared to the first iteration, the energy imported from the grid, used in the battery and generated by the Fuel cell remains almost the same, but the usage of the battery during the day changes. More energy remains stored between 15:00 and 7:00. This change in operation increases the cost of imported energy from the grid by 11.4 [$] and reduces the power payment by 6.3 [$]. The most important change is the reduction of reliability penalty from 72.64 [$] to 0 [$], as can be seen in

Table 48. This means that in the case of an outage the MG will now be capable of maintaining the services with no unsupplied energy.

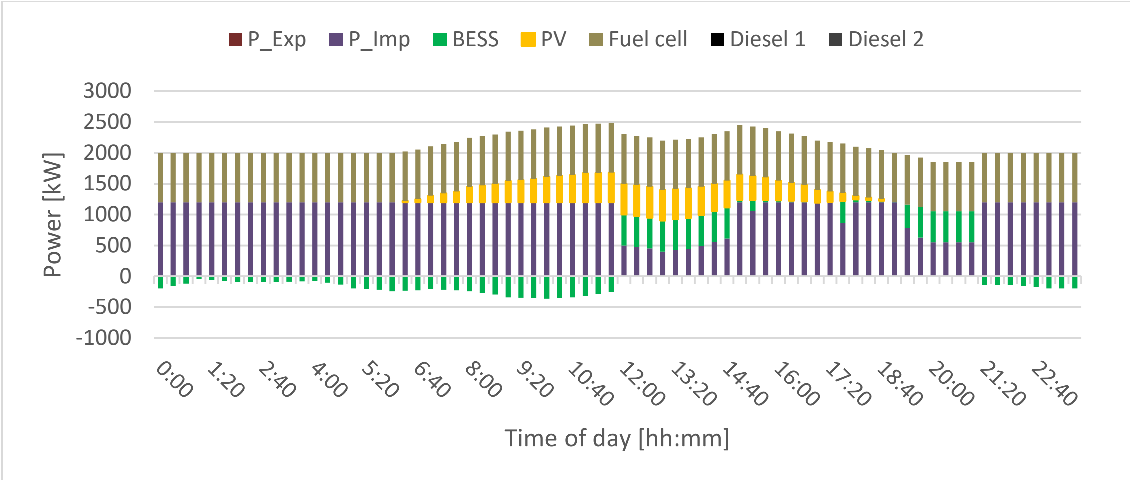

Figure 75: Operation for case study 19, Iteration 3

Table 47: Operation Summary of all units for case study 19, Iteration 1

Unit	Item	Value	Units
Fuel cell	Op. Time	24	[h]
	Energy	19,200	[kWh]
	Fuel cost	1,389	[$]
	Gen cost	0.072	[$/kWh]
Diesel	Op. Time	0	[h]
	Fuel	0	[l]
	Fuel cost	0	[$]
	Gen cost	0	[$/kWh]
Battery	Ex. Lifetime	7,300	[days]
		20	[years]
	Usage value	958.9	[$]
	Disch. Power	210.6	[kW]
	Disch. Energy	2,933.7	[kWh]
	Usage cost	0.31	[$/kWh]
	Rd. Trip Eff.	95%	[%]
Exp Grid	Energy	0	[kWh]
	Total Cost	0	[$]
	Av. Cost	0	[$/kWh]
Imp Grid	Energy	25,220	[kWh]
	Total Cost	2,556	[$]
	Av. Cost	0.101	[$/kWh]
NSE	Energy	0	[kWh]
	Cost	0	[$]
Peak	Power	1,212.67	[kW]
	Cost	301.15	[$]

Reliability	Cost	72.64	[$]
Total cost		5,277.34	[$]

Table 48: Operation Summary of all units for case study 19, Iteration 3

Unit	Item	Value	Units
Fuel cell	Op. Time	24	[h]
	Energy	19,200	[kWh]
	Fuel cost	1,389	[$]
	Gen cost	0.072	[$/kWh]
Diesel	Op. Time	0	[h]
	Fuel	0	[l]
	Fuel cost	0	[$]
	Gen cost	0	[$/kWh]
Battery	Ex. Lifetime	7,300	[days]
		20	[years]
	Usage value	958.9	[$]
	Disch. Power	195.9	[kW]
	Disch. Energy	2,728.1	[kWh]
	Usage cost	0.334	[$/kWh]
	Rd. Trip Eff.	95%	[%]
Exp Grid	Energy	0	[kWh]
	Total Cost	0	[$]
	Av. Cost	0	[$/kWh]
Imp Grid	Energy	25,209	[kWh]
	Total Cost	2,567	[$]
	Av. Cost	0.102	[$/kWh]
NSE	Energy	0	[kWh]
	Cost	0	[$]
Peak	Power	1,195.42 .	[kW]
	Cost	296.86	[$]
Emissions	Revenue	0	[$]
	Energy	0	[kWh]
	Av. Cost	0	[$/kWh]
Reliability	Cost	0	[$]
Total cost		5,211.47	[$]

The State of Charge of the BESS for Iteration 1 and 3 are presented in Figure 76. We can see that the SoC is maintained higher between 15:00 and 7:00 in the third iteration than in the first iteration.

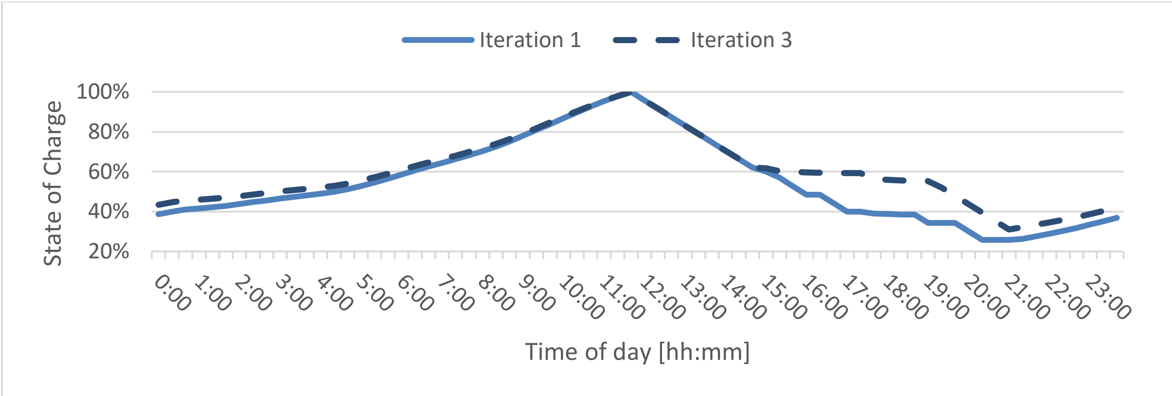

Figure 76: State of Charge for Iteration 1 and 3, case study 19

Table 49 presents the objective function and NSE for each slave for each iteration. There is NSE present only for the longest outages and it is reduced in each iteration by increasing the amount of stored energy in the BESS.

Table 49: Slaves results for case study 19

	NSE [kWh]		
	Iteration 1	Iteration 2	Iteration 3
Slave 1	0	0	0
Slave 2	0	0	0
Slave 3	0	0	0
Slave 4	0	0	0
Slave 5	287.8	129.3	0.0
Slave 6	0	0	0
Slave 7	0	0	0
Slave 8	0	0	0
Slave 9	0	0	0
Slave 10	0	0	0
Slave 11	0	0	0
Slave 12	0	0	0
Slave 13	0	0	0
Slave 14	0	0	0
Slave 15	0	0	0
Slave 16	0	0	0
Slave 17	0	0	0
Slave 18	0	0	0
Slave 19	0	0	0
Slave 20	240.5	0.0	0.0

The BESS has thus being kept at a higher SoC in case an outage occurs at 1:00 or 19:00, allowing the BESS and Fuel cell to keep the microgrid supplied until the diesel generator starts up and then the three units combined allow the SRJ MG to be supplied until the service is restored.

4.3.14 Result analysis – Santa Rita Jail

Energy management for a critical load like SRJ has different challenges than industrial or residential loads, both in size and in required reliability, especially when connected to a feeder that tends to overload in certain seasons.

Scenarios 13 and 14 show the operation of the SRJ during summer, with and without the possibility to sell energy to the grid. In neither scenario the optimizer exports energy to the Grid, mainly due to the low net-billing price (60%). This makes the difference between selling during peak hours (.08424 [$/kWh]) and buying energy during off-peak hours (.07992 [$/kWh]) really small (.000432 [$/kWh]), giving little incentive to arbitrage energy to the grid compared to the price of using the BESS. Thus all generated energy is used internally.

In scenario 15, the payment for power is included and leads to one of the most notable reductions in operational costs. Compared to scenario 14 there is a difference in payment for power of 196 [$] per day, or 5,876 [$] per month. This exemplifies how important it is to include both power and energy markets on a MG dispatch.

Table 50: Summary of case study 13-19

	Op. Cost [$]	CB [kW]	Summary
Scenario 13	$ 5,375.03	-	-
Scenario 14	$ 5,362.20	-	Emissions & Arbitrage
Scenario 15	$ 5,204.71	-	+ Peak shaving
Scenario 16	$ 5,222.85	7.2	Capacity bidding (May)
Scenario 17	$ 5,222.11	400	Capacity bidding (June)
Scenario 18	$ 4,996.71	400	Capacity bidding (July)
Scenario 19	$ 5,211.47	-	Islanding Reliability

Scenarios 16, 17 and 18 allow the MG to provide CB service during peak hours in summer on different months. Accordingly, the only difference between these three case studies is the remuneration that IESO offers. On May the payment is 3.04 [$/kW], on June its 3.71 [$/kW] and it peaks on July at 15.6 [$/kW]. In the first scenario, while there are some economic benefits, the expected cost of the studied slaves ends up being higher than the revenue obtained for providing this service, and thus the optimizer minimizes the offered CB. When the cost of this service increases in June, the benefit is slightly higher than the cost of the slaves, and a net benefit of 35.74 [$] is obtained, which represent a 0.67% reduction in operational cost. This benefit increases considerably during the July simulation when the net benefit reaches 208 [$] per day or 6,240 [$] per month. This represents a reduction in cost of 3.89%, similar to the commonly used service of peak-shaving observed in scenario 15. Both opportunities were taken advantage of in scenario 17 for a net reduction in cost of 8.94% compared to the base scenario (scenario 12). This last scenario shows for MG how important offering services to the main grid can be, making use of the MG already existing flexible equipment.

The last scenario includes the possibility of an unexpected interruption in supply at different moments of the day and with variable durations, using a master-slave scheme with Bender's decomposition, penalizing non-supplied energy. The initial operation presents some NSE in case of extended blackouts, which are reduced in multiple iterations by increasing the amount of stored energy on the BESS during the night. The proposed model increases the operational cost but reduces the risk of not having enough available energy for an unplanned outage. This is of high importance for MG that are interested in offering their services to the main grid without reducing the reliability of critical loads. Thanks to the quick resolution of each slave, the number of slaves used with this technique can be quite high without significantly increasing the total time.

The simulation results in the SRJ MG show that real microgrids can effectively provide services to the EPS. To achieve this, a robust optimal EMS was used, which not only obtains the operation optimum but also finds the best state of charge for the battery in each moment in case of unplanned islanded operation.

5 CONCLUSIONS AND FUTURE WORK

In this thesis, a robust optimal energy management system for a MG offering services has been studied and developed.

Based on the state of the art presented in section 2.2, the following phenomena were considered the most significant for BESS: cyclical aging, calendar aging, Peukert's law, capacity fading, self-discharge and charge/discharge limitations. A model for each of them was proposed.

The state of the art presented in section 2.5 shows that a MG can indeed offer many services to the Grid. In this thesis, the following services were modeled: energy arbitrage, demand response, emissions reduction, spinning reserve, peak shaving and capacity bidding.

Three different Benchmark microgrids were studied: the islanded microgrid of Huatacondo, the benchmark CIGRE MG connected in Ontario, and the connected MG of SRJ. Nineteen cases where generated for the operation of the MG, considering different models for BESS and offering a different combination of services.

Scenarios 1, 2, 3, 9 & 10 evaluated different aspect of the detailed BESS model presented in section 3.4. Scenarios 1 & 3 showed cyclical aging as the most important phenomena for islanded microgrids, which extended the battery life by 23.2%. For connected MG calendar aging takes precedence over cyclical aging, as can be seen in scenarios 8 & 10, in which the operational cost is reduced by 1.2% with the inclusion of calendar aging, while cyclical aging has little to no effect. Scenario 2 showed how the inclusion of Peukert effect can improve the BESS efficiency by 1%.

Scenarios 11-19 simulated the MG offering different possible services. From the studied scenarios, energy arbitrage and emission reduction presented the least impact in operational cost reduction for MG, with less than 0.2% in reduction. Peak shaving, demand response, spinning reserve and capacity bidding, when used alone or in combination, reduced the operational cost between 2.8% and 7%. Of the evaluated services, those based on trading energy in bulk were not attractive for the MG due to the high cost of use of the BESS. Services that offer flexibility to the Grid (capacity bidding, spinning reserve, etc.) were the preferred services due to a negligible increase in cost for the MG and major benefits for the grid.

The question of whether it is possible to offer services without compromising the MG reliability is answered in scenario 19. The BESS is kept at a higher SoC than in Scenario 18 during specific hours, to ensure that even if a blackout happens Santa Rita Jail will have enough stored energy to operate. The obtained optimal dispatch not only minimized the operational costs, it also satisfied reliability conditions.

The simulation results indicate that a MG, by making optimal use of the small and varied DER which comprises it, can offer a significant contribution to the grid and obtain better economic options making use of its already existing flexible units.

5.1 FUTURE WORK

Based on the research presented in this thesis, possible future research can be conducted. Some ideas for future work are presented below:

- The proposed model presented in this thesis does not consider uncertainty in renewable generation or load consumption. Stochasticity on these aspects could be added using Monte Carlo Analysis.
- Some aspects of the BESS phenomena proposed in section 3.4 were not evaluated, such as the effect of temperature, effective capacity and self-discharges. The evaluation of these factors using an electrochemical model could help identify their importance.
- In this thesis, the control and the energy management are performed with a single MG. Considering the current trends, the proposed model could be expanded into a multi-microgrid management system. This could be done with the inclusion of multiple electrical buses to the model presented in this thesis.
- Only a few of all the possible services a MG can offer where analyzed in these simulations. Reduction in electrical losses, reactive power support, Investment deferral and black-start capability could be evaluated on future work.

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7 ANNEXES

7.1 ANNEX I: CARBON EMISSION DISPLACEMENT CALCULATION

The authors of [**96**] propose a generalized methodology that allows the estimation of emissions based on marginal price. In vertically-structured utilities, generators are dispatched under a cost-based approach that minimizes the total operating cost of the different types of generation. This process is equivalent to the maximization of the social welfare, where all cost information is openly available to the public. Therefore, the dispatch of the different power plants depends directly on the costs of fuel, which is dictated by the fuel markets (for fossil-fuel, thermal generators) or the perceived future value of stored water (for hydro generators).

On the other hand, for power systems that operate in the presence of an electricity market, the different generators are dispatched following a price-based minimization that takes in bids from the participating generators. These bids may or may not reflect the actual costs of fuel. Under this market structure, all information regarding operating costs is confidential. The order in which the power plants are dispatched depends on price offers from generators. However, in competitive markets, generators are compelled to offer selling prices close to their marginal production costs; therefore, the dispatch order may as well follow the trends of the fuel markets.

Figure 77 shows a typical system's load duration curve (LDC), which indicates the number of hours, in this case, a year or 8760 hours, in which the system demand exceeds any given power demand. The figure also shows how the various generating technologies are typically dispatched to meet the different demand levels. All technologies that operate below the minimum system demand level d_{min} are said to operate at the base. In this example, nuclear operates as the base. Due to their limited flexibility and high investment costs, nuclear power plants are usually scheduled to operate at near maximum capacity for as long as possible. The remainder of the dispatch "stack" is usually determined by the generating costs (fuel) and efficiency. Thus, as the demand increases, hydro plants are then dispatched, followed by coal, gas and finally peaking oil plants or a mix of high cost generating units.

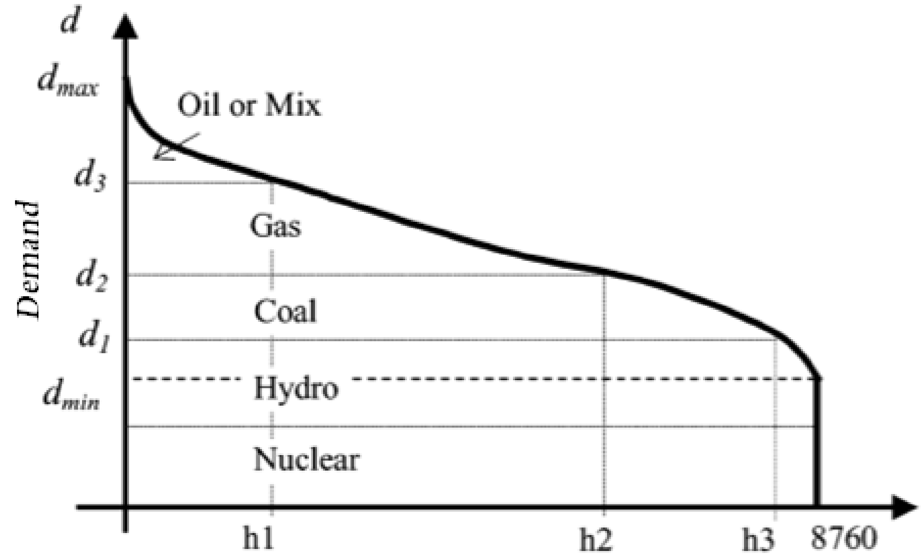

Figure 77: Load duration curve and generation dispatch order. [**96**]

All technologies that are dispatched above the minimum demand (above d_{min}) will operate at the margin during some time of the year. For instance, Figure 77, it can be seen that the gas plants operate at the margin during h_2-h_1 hours, coal plants during h_3-h_2 and part of the hydro plants during hours 8760-h_3. The most expensive oil plants will operate at margin during the highest h1 peak demand hours.

The LDC, together with the demand-generation dispatch order determine what will be called here the marginal emissions-demand (MED) curve, which represents the system marginal emissions as a function of the demand level, $E_m(d)$. These marginal emissions obviously depend on the emission levels of each of the marginal units. Figure 78 shows the MED that corresponds to the LDC given in Figure 77, based on its dispatch order. For instance, the system marginal emissions between demand d_2 and d_3 will be those of the gas plants that operate at margin within that particular demand range, as shown in Figure 78.

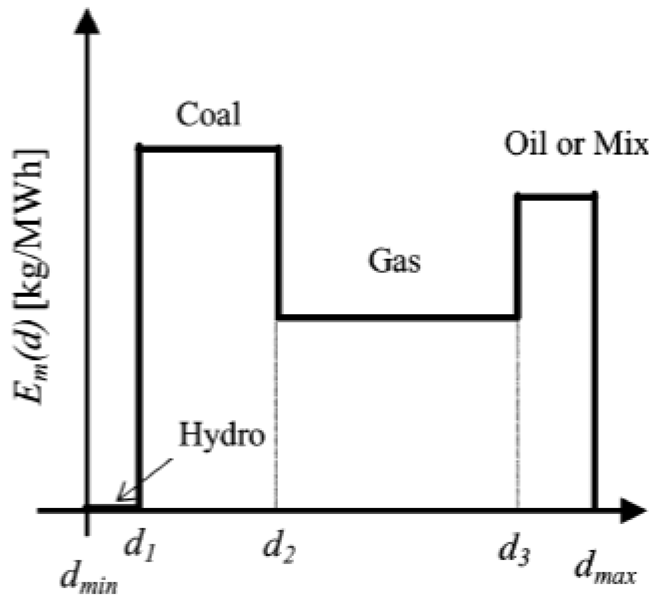

Figure 78: Marginal emissions curve. [**96**]

for every MWh of MG generation produced at a certain hour during the day, we can assume that there will be another MWh of production that will be backed off from the marginal unit/technology operating at that particular hour or demand level. The emissions displaced or avoided by the MG at a particular hour are therefore given by the emissions of the marginal plant/technology operating at that particular hour or demand level.

We can now apply this exact same concept to a daily dispatch. The upper part of Figure 79 represents a typical daily demand curve, showing how the total system demand progresses along the 24 hours of a typical day. The generating technologies are dispatched according to the fluctuating demand, as explained in Figure 77. Now, the bottom part of Figure 79 shows the convolution of the time-demand curve with the Em(d). This curve is what called the time-marginal emissions curve and indicates the time evolution of the system's marginal emissions (Em) and can be readily calculated if the system's generating units and the daily demand curves are known. Therefore, typical curves can be compiled for each representative day (business or weekend day) or can be estimated using available hourly data for demand and generation dispatch.

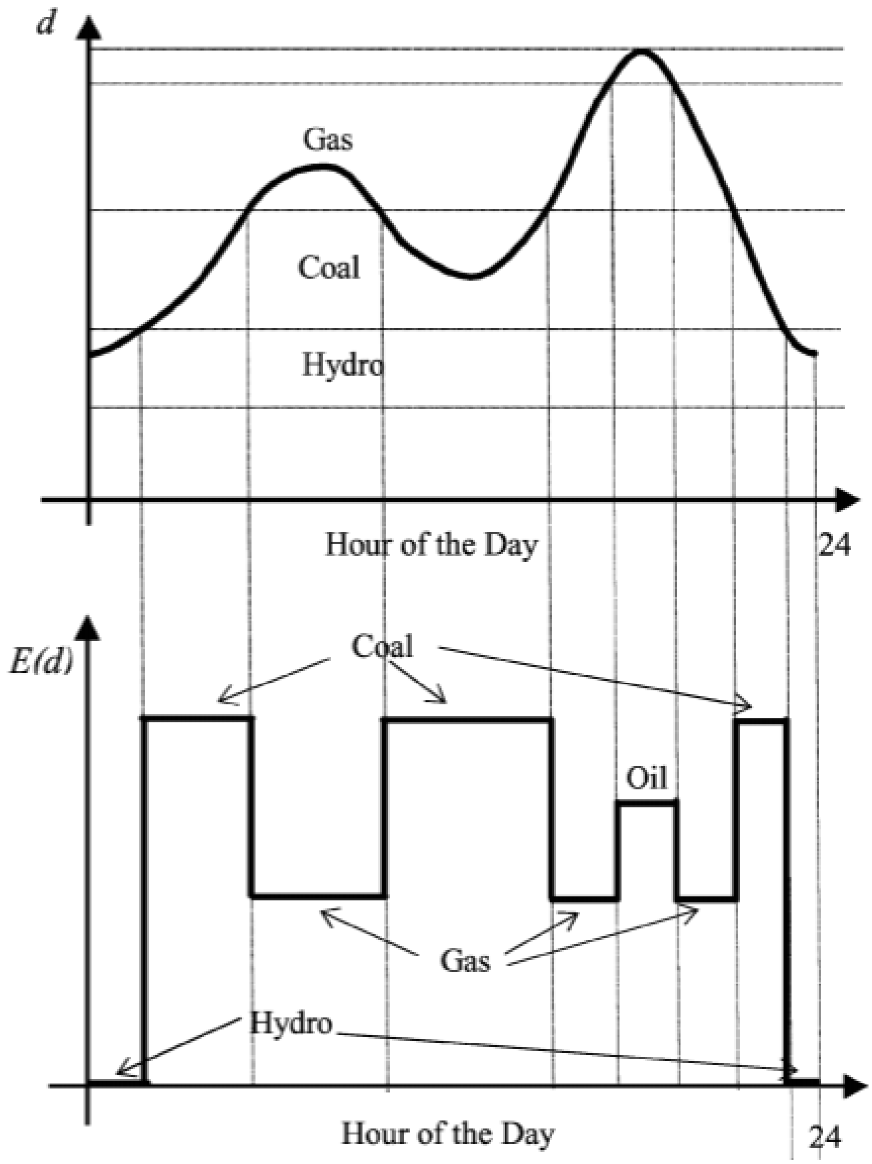

Figure 79: Daily demand curve and time-marginal emissions curve. [**96**]

This method assumes that a MWh of MG output at a particular hour will displace the emission rate of the marginal conventional unit operating at the same hour. It is also assumed that the MG output is not large enough to completely displace the marginal technology. This means the assumption is valid for relatively low penetrations of MG.

The efficiencies for different types of power generating plant are obtained from [**104**] and shown in Table 51, which represent average values for existing power stations. Hydro and renewable sources are taken to have no significant carbon emissions associated with their production. For simplicity, it is assumed zero emissions for pumped storage hydro and nuclear generated electricity.

Table 51: Power plant efficiencies. [**104**]

	Efficiency		Efficiency
AGR	N/A	Medium coal	33%
CCGT	45%	OCGT	31%
Coal/gas	34%	Oil	35%
Coal/oil	34%	Pumped hydro	N/A
External	N/A	PWR	N/A
Gas	36%	Small coal	31%
Large coal	35%	Magnox	N/A

Table 52 shows the carbon coefficients for fuels used to generate electricity. These are delivered energy emission factors including upstream emissions from fuel extraction processing and distribution, but not transport.

Table 52: Carbon contents of fuel. [**104**]

	Gas	Oil	Coal
tC/MWh	0.052	0.071	0.082

By combining the operational efficiency of each generating plant with the appropriate emission factor we can get the emission factor for different types of generating plant. See Table 53.

Table 53: Carbon emissions for each type of generating plant. [**104**]

Plant type	tC/MWh
Small coal	0.27
Medium coal	0.25
Large coal	0.24
Oil	0.22
OCGT	0.25
Gas	0.15
Coal/gas	0.22
Coal/oil	0.24
CCGT	0.12
Nuclear, pumped hydro & external sources	0

7.2 ANNEX II: INVESTMENT DEFERRAL VALUE

A method to estimate the present value (PV) of future investment is presented in [**72**]. The present value for an investment of C_i cost in year Y_i at interest rate *d* is

$$PV = \frac{C_i}{(1 + d)^{Y_i}} \qquad (83)$$

If the presence of the MG allows deferring an investment, C_i from year Y_{BC}, for the Base Case, to year Y_{MG}, for the case with a MG, the total benefit will be the difference between the present value in the base case, PV_{BC} and that in the Microgrid case PV_{MG}

$$PV = PV_{BC} - PV_{MG} = C_i * \left(\frac{1}{(1 + d)^{Y_{BC}}} - \frac{1}{(1 + d)^{Y_{MG}}} \right) \qquad (84)$$

If a number of affected network components are taken into account, the total investment deferral can be calculated as

$$Total\ Inv.Def. = \sum_{t=1}^{h} \sum_{i=1}^{n} \frac{C_{i,t}}{(1 + d)^t} \Bigg|_{BC} - \sum_{t=1}^{h} \sum_{i=1}^{n} \frac{C_{i,t}}{(1 + d)^t} \Bigg|_{MG} \qquad (85)$$

where *t* is the time step from 1 to the end of the planning horizon, *h*. Variable *n* is the number of investments required in time step *t*. $C_{i,t}$ is the cost of asset *i* in time period *t*, and ρ is the interest rate.

7.3 ANNEX III: INVESTMENT DEFERRAL CALCULATION MODEL

A simple model to calculate this cost is proposed by Gil et al in [**81**], where the Present Value (PV) of MG *i* follows the equation

$$PV_i = \sum_f C_f \left(1 - \frac{1}{e^{dT_{fi}}}\right) \quad (97)$$

where C_f is the cost of the needed upgrade of feeder f (with no MG), d is the interest rate (monthly or annual) and T_{fi} is the time (in months or years) by which the investment on feeder *f* is deferred by the firm operation of a MG located at bus i during peak load hours. The quantification of this benefit depends largely on the DU's cost-structure and expansion strategies, the type of feeder and region served.

Antonio et al presents in [**83**] another way to calculate the investment deferral benefit, based on the method proposed by Wang et al [**112**] that proposed that the deferral time should be based on the time the reinforcements are actually required. The PV for such investments is calculated using the total cost of the group, C_g, the scheduled year Y_g, and the real interest rate, *d*:

$$PV = \frac{C_g}{(1+d)^{Y_g}} \quad (98)$$

Similarly, the present value of the investments required for the same group g, when a MG is connected to bus *i*, will be based on the new scheduled year Y_g^{MGi}:

$$PV = \frac{C_g}{(1+d)^{Y_g^{MGi}}} \quad (99)$$

Consequently, the net benefit to the utility, Bg^{MGi}, obtained by postponing a planned investment in a particular group g, from year Y_g to Y_g^{MGi}, due to the presence of a generator at bus *i*, is given by the difference of the corresponding present values

$$B_g^{MGi} = \frac{C_g}{(1+d)^{Y_g}} - \frac{C_g}{(1+d)^{Y_g^{MGi}}} \quad (100)$$

The total benefit, B^{MGi}, to the utility brought about by the MG unit located at bus i corresponds to the sum of all the benefits obtained in all the groups of feeders:

$$B^{MGi} = \sum_{g \in G} B_g^{MGi} \qquad (101)$$

where *G* is the set group of feeders.

7.4 ANNEX IV: BLACK START CAPABILITY REQUIREMENTS AND MG

The authors of [**88**] identify the following range of attributes to quantify the black start potential for a wide range of different energy storage technologies, common among MGs, and gives an evaluation on the MG performance in each of these aspects:

<u>Proximity to other stations and black start stations (++)</u>

Black start stations should ideally be located in electrical proximity to other non-black start sites. A reasonable geographical distribution of black start services should be provided.

Energy Storage plants can be built integral and in combined mode with existing thermal and other generation units, adsorbing and converting energy losses into restorative energy.

<u>Start-up time from cold, restarting ability (+)</u>

Start-up capability of a black start provider is defined as the ability to start the main station generating plant (at least one unit) from shutdown without using external power supplies; the provider should be ready to energise part of the transmission or distribution system within two hours of instruction. Fast start up from cold is critical.

The ability to provide at least three sequential black start operations, to allow for possible further tripping of the system or the black start site is also required.

ESS are not constrained by mechanical and thermal limitations, and have a fast response. Ramp up rates are dependent on technology, demand duration needs to be considered.

<u>Independent fuel supplies, fuel (dual fuel) availability (++):</u>

ESS are fuel independent, as they can be charged and ready for release at short notice.

Frequency and voltage regulation, inertia (+)

Voltage, rotor angle and frequency must be maintained within certain margins during the restoration process. These tend to be unstable and particularly susceptible to relatively large variations in the case of an islanded network; with formation of discrete 'islands' within the network being a key step in the restoration process. The black start provider should thus be capable of dynamically responding to these voltage and frequency variations.

Expected availability and reliability of station (+)

A black start provider should be available at any time the service is required and the station should be able to restart with a high level of reliability.

The predictions on availability for ESS are positive, with some lead-acid system maintenance concerns. While efficiency is the main limitation of energy storage, particularly if the store-release cycle is considered, this does not apply for black start.

Training and testing requirements (+)

Technical performance is not the sole measure of the black start potential of a technology; actual testing and training requirements in order to meet the required service levels are of critical importance. Determination of testing requirements in terms of equipment, time, personnel and related system disturbance are essential for any non-traditional technology that is not primarily designed for black start.

The use of energy storage for black start should not present an issue to training. Aggregation, control and feedback when energy storage is integrated with distributed generation also needs to be tested and verified

Black Start Potential of Energy Storage

There are requirements of Power (MW) and capacity (MWh) of any ESS that intends to be used in BS capacity. The battery storage power and capacity is defined by the converter and the battery design respectively, which are selected according to the desired application. For a BS capacity, the range of duration should be between 2 and 10 hours, as shown in Table 54.

Table 54: Applications and discharge duration of storage. [117]

Storage Application	Discharge Duration
spinning reserve	20s-1min
primary frequency control	<15s
Flicker compensation	<60s
voltage sag/swell mitigation	10ms-60s
uninterruptible power supply (UPS)	1s-30s
integration of intermittent renewables	5min-20min
islanded microgrid	20s-hours
peak shaving	4h-8h
load levelling	4h-12h
black start capability	2h-10h
non-spinning reserve	10min-2h

There are requirements of Power (MW) and capacity (MWh) of any ESS that intends to be used in BS capacity. The battery storage power and capacity is defined by the converter and the battery design respectively, which are selected according to the MG purpose.

7.5 ANNEX V: REQUIREMENTS FOR A BLACK START UNIT IN THE WORLD

The requirements for black start units are plenty and vary from country. In the case of UK, the following seven characteristics are required [**87**].

1. The ability to start up the main generating plant (at least one unit/module) of the station from shutdown without the use of external power supplies, and be ready to energise part of the Network Electricity Transmission System or, if appropriate, the Network Distribution System within two hours of instruction.
2. The capability to accept instantaneous loading of demand blocks, ideally in the range 35 to 50 MW, and controlling frequency and voltage levels within acceptable limits during the block loading process (under these conditions, frequency can be within the range 47.5 to 52 Hz);
3. The ability to provide at least three sequential Black Starts, to allow for possible tripping of the Transmission/Network Distribution System(s) during the re- instatement period or trips during the station's starting sequence itself;
4. Back-up fuel supplies (e.g. distillate fuel), if appropriate, to enable the power station to run for a minimum duration, ideally in the range 3 to 7 days, following a Black Start instruction;

5. Facilities to ensure that all generating units can be safely shutdown without the need for external supplies, and can be maintained in a state of readiness for subsequent start-ups;
6. The ability to maintain a high service availability on both the main and auxiliary generating plant (typically 90%); and
7. The reactive capability to charge the immediate Transmission/Network Distribution System(s). This capability will depend on the local system configuration, but generating plant connected at 400kV or 275kV with a capability of at least 100MVAr leading (as measured at the commercial interface) should almost invariably meet this requirement. The generator must also be capable of withstanding the magnetic inrush and transient voltages associated with this charging duty.

Often hydroelectric power plants are designated as the black-start sources to restore network interconnections. A hydroelectric station needs very little initial power to start (just enough to open the intake gates and provide excitation current to the generator field coils), and can put a large block of power on line very quickly to allow start-up of fossil-fuel or nuclear stations.

In the Western part of Australia, Western Power specifies these requirements for units that desire to provide BS [**88**]:

1. Nominal power output of a black start unit must be greater or equal to 20MW.
2. Fuel reserves must be sufficient to enable at least 48 hours of operation.
3. As in the case of current NGET specifications, the capability for at least three sequential black starts should be provided.
4. A mitigation plan should be implemented regarding critical starting equipment, where its failure can compromise the ability of station to offer black start service.
5. Air pollution restrictions are waived during a black start event. This allowance sets a precedent when future CCS sites are considered.
6. Stable operation at low loads of 1MW to 5MW is required.
7. Automatic frequency regulation under operation in isochronous governor mode is requested.
8. The black start unit must be able to operate in a voltage range of 0.95pu to 1.05pu with its rated voltage as base.
9. Stable operation in under excitation mode is requested.

10. Remote control capability is required for sites that are not staffed on a 24/7 basis; emergency communication functionality with the system control center and a staff mobilization plan is also requested for all sites.

And our final example, the American Transmission Company (ATC), assesses its potential black start providers against a list of criteria defined as [**88**]:

1. Location in relation to prioritized non-black start units.
2. Frequency control, including real power capability and operation near zero and 5% 'droop'.
3. Reactive power capability and voltage regulation, no actual leading MVAr margin is defined.
4. Whilst station start up times greater than 60 minutes are generally not favored, the TSO does not explicitly state that sites violating this margin will not be considered as black start providers.
5. Fuel availability and especially dual fuel capability is a further criterion.
6. Training and testing against the North American Electric Reliability Corporation (NERC) reliability standards is requested every two years.
7. Investigation is called on the inertia of black-start unit in relation to the inertia of prioritized non-black start stations.
8. Ability of station to be restarted at least three times along with the period of time required prior to any restart. Assessment of battery capacity or any other start up system is specifically mentioned in the context of this item.