Generation Scheduling in Microgrids under Uncertainties in Power Generation

by

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AUTHOR'S DECLARATION

I hereby declare that I am the sole author of this thesis. This is a true copy of the thesis, including any required final revisions, as accepted by my examiners.

I understand that my thesis may be made electronically available to the public.

Abstract

Recently, the concept of Microgrids (MG) has been introduced in the distribution network. Microgrids are defined as small power systems that consist of various distributed micro generators that are capable of supplying a significant portion of the local demand. Microgrids can operate in grid-connected mode, in which they are connected to the upstream grid, or in isolated mode, where they are disconnected from the upstream grid and the local generators are the only source of power supply. In order to maximize the benefits of the resources available in a microgrid, an optimal scheduling of the power generation is required. Renewable resources have an intermittent nature that causes uncertainties in the system. These added uncertainties must be taken into consideration when solving the generation scheduling problem in order to obtain reliable solutions.

This research studies the scheduling of power generation in a microgrid that has a group of dispatchable and non-dispatchable generators. The operation of a microgrid during grid-connected mode and isolated mode is analyzed under variable demand profiles. Two mixed integer linear programming (MILP) models for the day-ahead unit commitment problem in a microgrid are proposed. Each model corresponds to one mode of operation. Uncertainty handling techniques are integrated in both models. The models are solved using the General Algebraic Modeling System (GAMS). A number of study cases are examined to study the operation of the microgrid and to evaluate the effects of uncertainties and spinning reserve requirement on the microgrid's expenses.

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Dedication

To my dear parents, for all what you have provided. I can never pay you back. May Allah help me bring delight and happiness to your eyes in this life and in the hereafter.

To the martyrs of the Syrian Revolution.

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Nomenclature

A. Indices

j	Index of dispatchable generation units, $j \in \{1, \dots, J\}$
k	Index of time periods, $k \in \{1, \dots, K\}$
s	Index of scenarios, $s \in \{1, \dots, S\}$

B. Variables

Z	Total expenses ($)
U_{jk}	Status of unit j at time k (0/1)
Ust_{jk}	Start-up decision variable of unit j at time k (0/1)
Usd_{jk}	Shut-down decision variable of unit j at time k (0/1)
P_{jk}	Power generated by unit j at time k (kW)
P_{jks}	Power generated by unit j at time k scenario s (kW)
$P_{GIn,ks}$	Power imported from the upstream grid at time k scenario s (kW)
$P_{GOut,ks}$	Power exported to the upstream grid at time k scenario s (kW)
$P_{shed,ks}$	Load shedding at time k scenario s (kW)
$P_{Curt,ks}$	Power curtailment at time k scenario s (kW)
$U_{shed,ks}$	Load shedding decision variable at time k scenario s (0/1)
$U_{curt,ks}$	Power curtailment decision variable at time k scenario s (0/1)
SRu_{jks}	Reserve provided by unit j at time k scenario s (kW)
$SRgrid_{ks}$	Reserve provided by the upstream grid at time k scenario s (kW)
$SRall_{ks}$	Available spinning reserve in the system at time k scenario s (kW)

C. Constants

J	Number of dispatchable units
K	Number of time periods in the scheduling horizon
S	Number of scenarios
ρ_s	Probability of scenario s
C_r	Reserve price ($/kWh)
C_{grid}	Upstream grid power price ($/kWh)

C_{DSM}	Load shedding and power curtailment price ($/kWh)
D_k	Forecasted system's demand at time k (kW)
SR_k	System's spinning reserve requirement at time k (kW)
D_{ks}	Forecasted system's demand at time k scenario s (kW)
W_{ks}	Forecasted wind power generation at time k scenario s (kW)
PV_{ks}	Forecasted solar power generation at time k scenario s (kW)
SR_{ks}	System's spinning reserve requirement at time k scenario s (kW)
P_j^{min}	Minimum output power of unit j (kW)
P_j^{max}	Maximum output power of unit j (kW)
P_{grid}^{max}	Capacity of the line linking the upstream grid and the microgrid (kW)
α_D	Load forecasting error factor
α_W	Wind power forecasting error factor
α_{PV}	Solar power forecasting error factor
μ	Upper bound for the if-condition linearization
HSC_j	Hot start-up cost of unit j ($)
CSC_j	Cold start-up cost of unit j ($)
CST_j	Cold start-up time of unit j (Hr)
DT_{jk}	Number of hours unit j has been off at time k (Hr)
UT_{jk}	Number of hours unit j has been on at time k (Hr)
CM_j	The crew start-up cost and maintenance cost of unit j ($)
RR_j	Ramp rate of unit j (kW/Hr)
MUT_j	Minimum up time of unit j (Hr)
MDT_j	Minimum down time of unit j (Hr)

Chapter 1
Introduction

1.1 Preface

The restructuring of electric power systems has changed the nature of power generation allowing smaller units to be distributed across the network and closer to the loads. These generators are referred to as Distributed Generators (DG). DG units can be classified into two main categories based on their nature: dispatchable generators (diesel generators, combined heat and power generators, etc.), and non-dispatchable renewable generators (wind, solar, etc.). The accommodation of distributed generators in the distribution networks is one of the most significant and challenging research topics in power engineering. The electricity grid is being restructured to allow for higher penetration levels of distributed generators in order to maximize their utilization. Microgrids (MG) have been recently introduced in distribution networks and are defined as small power systems that consist of various distributed micro generators which are capable of supplying a significant portion of the local demand. Microgrids provide multiple benefits to the system including reducing customers' interruption costs, reducing system losses, and accommodating higher penetration levels of renewable resources [1], [2]. Microgrids can operate in grid-connected mode, in which they are allowed to exchange power with the upstream grid, or in isolated mode, where they are disconnected from the upstream grid and the local generators are the only source of power supply. An Energy Management System (EMS) is used in microgrids to optimize their operation, schedule local generation, and control all the interactions with the upstream grid. Optimizing the operation of a microgrid is essential to reduce fuel costs, energy not served, power losses, and gas emissions.

In order to maximize the benefits of the resources available in a microgrid, an optimal scheduling of the power generation is required. Generation scheduling problem is an optimization problem that consists of two sub-problems: Unit Commitment (UC), and Economic Dispatch (ED). The unit commitment problem provides the on/off status of the dispatchable generation units over a daily or weekly time horizon. On the other hand, the economic dispatch problem finds the optimal output power for the units committed by the unit commitment problem over shorter time horizons: i.e., hourly or in real time. Both problems search for an optimal solution that satisfies the generators' and network's constraints while meeting the demand and the reserve requirement. In large power systems, unit commitment problem deals with large generation plants of hundreds to thousands of megawatts. While in microgrids, generation capacities are in the range of tens of kilowatts to few megawatts.

This reduction in the size affects the operation parameters of the generators leading to more flexible and frequent on/off switching actions [2].

One of the benefits of establishing microgrids is increasing the penetration of renewable resources in the grid. However, a major problem with this kind of generators is their intermittent nature. The amount of power generated by renewable resources solely depends on the weather parameters such as wind speed and solar radiation. Therefore, these generators cannot be dispatched nor committed like classical thermal generators. Furthermore, renewable generators can cause load mismatch and voltage instability in the system [3]. These problems are more significant in the case of microgrids due to having a higher penetration level of renewable generators compared to large power systems. Uncertainties associated with renewable generators must be taken into consideration when scheduling the power generation in microgrids in order to achieve reliable solutions. Hence, reformulating the scheduling problem and developing new models is a necessity to produce efficient and robust commitment schedules.

Microgrids can operate under two different modes of operation. The major difference between the two modes is the sources of power generation that can be used to supply the demand and the reserve requirement. This has a direct impact on the generation scheduling problem making it more challenging. Therefore, the formulation must be updated to account for the objectives and constraints of each mode of operation. Doing so will result in a better distribution of the available generation capacities in the microgrid and will allocate the required amount of spinning reserve to maintain the system's stability and to mitigate the effects of uncertainties.

Developing more accurate and reliable scheduling models that account for the effects of uncertainties and modes of operation is the main motivation behind this research. The work presented in this thesis will examine the impacts of these added difficulties on the day-ahead unit commitment problem which is the first stage of the generation scheduling problem in a microgrid. Two optimization models will be presented; one for each mode of operation. The proposed models will tackle uncertainties by integrating uncertainty handling techniques in the problem formulation. A number of study cases will be presented to study the operation of a microgrid, and to evaluate the effects of uncertainties and spinning reserve.

1.2 Objectives

The main objectives of this thesis can be summarized in the following points:

- Study the day-ahead unit commitment problem in microgrids during grid-connected and isolated mode under variable demand profiles.
- Develop mathematical optimization models that can solve the day-ahead unit commitment problem in microgrids during different modes of operation.
- Integrate uncertainty handling techniques into the day-ahead unit commitment problem and evaluate the effects of uncertainties on the expenses of microgrids.
- Examine the effects of spinning reserve on the operation and expenses of microgrids.

1.3 Thesis outline

The thesis is organized as follows. Chapter 2 provides a literature review about the topics related to this research including the classical unit commitment problem, microgrids, and generation scheduling in microgrids. Chapter 2 also reviews few uncertainty handling techniques and the previous studies that applied them. Chapter 3 discusses in details the operation of microgrids during grid-connected mode and isolated mode. It also presents the uncertainty handling techniques that will be integrated with the proposed models. Furthermore, the mathematical formulations of the models to solve the day-ahead unit commitment problem in microgrids are given. Chapter 4 shows the results of several analysis and study cases using the proposed models. The examined study cases investigate the operation of the microgrid during both modes of operation and evaluate the effects of uncertainties and spinning reserve requirement on microgrids' operation and expenses. Finally, conclusions and suggested future work are provided in Chapter 5.

Chapter 2
Literature Review

This chapter provides a literature review about few topics related to the research presented in this thesis. The first part reviews the classical unit commitment problem and its formulation. A review about microgrids is then presented including their definition, structure, and control. After that, recent research articles about the topic of generation scheduling in microgrids are summarized and evaluated. The last part in this chapter discusses the sources of uncertainties in the unit commitment problem, and the suggested tools and techniques presented in the literature to tackle them.

2.1 Unit commitment

Electrical power generators are bounded by a set of constraints that limit their operation. Generators cannot turn on or off instantly and their output power cannot exceed certain ramp rates. This causes an inflexible operation and might limit the power production during certain time periods. Therefore, it is essential to commit the generation units in advance to reliably meet the demand and the reserve requirement of the system. The Unit Commitment (UC) problem schedules the power generation in a power system with the objective of minimizing the operating cost while satisfying a set of system's and units' constraints over a period of time [4]. The unit commitment problem defines the on/off status and duration of the dispatchable generation units over a daily or weekly time horizon. It also determines the power production needed from each committed unit in order to meet the system's demand. For a large scale power system, the unit commitment problem is considered to be computationally complex due to having a large number of continuous and integer variables along with nonlinear equations. The problem can be solved using well known algorithms such as dynamic programming, and lagrangian relaxation [5].

Power production levels are rescheduled using the Economic Dispatch (ED) problem which runs over a shorter time horizons: i.e., hourly or in real time. The economic dispatch problem does not affect the commitment of the units, i.e. it does not turn on or off any of the generation units. However, it modifies the power production levels based on the updated forecast of the system's demand taking into consideration more constraints such as power flow and transmission capacity. The economic dispatch problem is mathematically easier than the unit commitment problem because all the variables are continuous without any integer variables.

The unit commitment problem is considered to be a large scale nonlinear mixed integer minimization problem. It contains a large number of integer variables, such as the units' on/off status, and continuous variables, such as the units' output power. The problem tries to minimize the operating cost which is represented using nonlinear equations. The unit commitment problem is usually formulated as a mixed integer linear programing (MILP) model. The following is a summary of the MILP formulation of the problem including the objective function and the problem constraints [4], [5], [6].

2.1.1 Objective function

The objective of the generic unit commitment problem is to minimize the operating cost that includes the start-up cost, the fuel cost, and the shut-down cost. The objective function can be represented as follows:

$$\min \quad Z = \sum_{k=1}^{K} \sum_{j=1}^{J} \left(C_j\left(P_{jk}\right) + SU_{jk} + SD_{jk} \right) \tag{2-1}$$

where $C_j\left(P_{jk}\right)$ is the fuel cost of unit j that supplies power P_{jk} at time k, and SU_{jk} is the start-up cost of unit j at time k, and SD_{jk} is the shut-down cost of unit j at time k. The shut-down cost is usually ignored and assumed to be equal to zero. The fuel cost is a nonlinear function of the power output [4].

$$C_j\left(P_{jk}\right) = a_j . U_{jk} + b_j . P_{jk} + c_j . P_{jk}^2 \quad , \qquad \forall j \tag{2-2}$$

where a_j, b_j, and c_j are the cost coefficients of unit j. The fuel cost can be simply linearized by dropping the quadratic term in Equation (2-2) [3].

$$C_j\left(P_{jk}\right) = a_j . U_{jk} + b_j . P_{jk} \quad , \qquad \forall j \tag{2-3}$$

The start-up cost SU_{jk} is modeled as an exponential function [4], [5].

$$SU_{jk} = CM_j + CSC_j \left[1 - e^{\left(\frac{DT_{jk}}{CST_j} \right)} \right] \quad , \qquad \forall j, k \tag{2-4}$$

The start-up cost can be simplified into a piecewise function that has two states. If the unit has been off for a period less than the cold start-up time (CST_j), the start-up cost is equal to the hot start-up cost (HSC_j). Otherwise, the start-up cost is equal to the cold start-up cost (CSC_j).

$$SU_{jk} = \begin{cases} HSC_j, & DT_{jk} < CST_j \\ CSC_j, & DT_{jk} \geq CST_j \end{cases} \quad , \qquad \forall j, k \tag{2-5}$$

Equation (2-5) can be linearized as follows [6]:

$$SU_{jk} \geq HSC_j \times (U_{jk} - U_{j(k-1)}) \quad , \qquad \forall j, k \tag{2-6}$$

$$SU_{jk} \geq CSC_j \times (U_{jk} - \sum_{i=1}^{CST_j} U_{j(k-i)}) \quad , \qquad \forall j, k \tag{2-7}$$

$$SU_{jk} \geq 0 \quad , \qquad \forall j, k \tag{2-8}$$

2.1.2 Constraints

The constraints in the unit commitment problem are classified into separable and coupling constraints [4]. Separable constraints such as generation limits and minimum up and down time limits are related to single generation units. On the other hand, coupling constraints such as power balance and reserve requirement constraints are affected by all the generation units in the system such that a change in any generation unit affects the rest of the units in the system.

A) <u>Dispatchable units' constraints:</u>

1. Power limits: If a unit is committed, its output power should be between the minimum and the maximum power limits of that unit.

$$P_j^{min} \leq P_{jk} \leq P_j^{max} \quad , \qquad \forall j, k \tag{2-9}$$

2. Ramp rate limit: During one time period, the increase or decrease in a unit's output power should not exceed the ramp rate limit.

$$P_{j(k-1)} - RR_j \leq P_{jk} \leq P_{j(k-1)} + RR_j \quad , \qquad \forall j, k \tag{2-10}$$

3. Minimum up and down time: If a unit is turned off, it has to remain off for a specific period of time before it can be turned on again. Similarly, if a unit is turned on, it has to remain on for a specific period of time before it can be turned off again.

$$Ust_{jk} = \begin{cases} 1, & UT_{jk} < MUT_j \\ 0, & DT_{jk} < MDT_j \end{cases} , \qquad \forall j,k \tag{2-11}$$

A computationally efficient linear equivalent representation of Equation (2-11) was presented in [6]. The new representation drops the extra integer variable Ust_{jk}, and uses only the unit status variable U_{jk}. The reduction in the number of integer variables helps in reducing the computational burden.

4. Logic constraint: A logic constraint is used to prevent turning a unit on and off at the same time which is illogical.

$$Ust_{jk} - Usd_{jk} = U_{jk} - U_{j(k-1)} , \qquad \forall j,k \tag{2-12}$$

B) System constraints:

1. Power Balance: The total amount of power generated in the system has to be equal to the total system demand. System losses are usually neglected during the unit commitment problem; however, they are accounted for in the economic dispatch problem.

$$\sum_{j=1}^{J} P_{jk} = D_k , \qquad \forall k \tag{2-13}$$

2. Spinning reserve requirement: The total committed capacity must be able to meet the system's demand and reserve requirement.

$$\sum_{j=1}^{J} (P_j^{max} \times U_{jk}) \geq D_k + SR_k , \qquad \forall k \tag{2-14}$$

2.2 Microgrids

2.2.1 Definition, structure, and control

The integration of distributed generators in the electric grid poses a number of challenges to the system's operators. One of the suggested methodologies is to locate a group of generators and loads next to each other such that they are seen by the rest of the electric grid as a single generator or load [7]. This is referred to as a Microgrid. Several types of generators are usually considered in a microgrid including dispatchable generators, such as micro-turbines and combined heat and power generators, and non-dispatchable generators, such as wind turbines and Photovoltaic (PV) systems. In addition to that, energy storage systems can also be integrated in microgrids. Microgrids are connected to the upstream grid at a single point called the Point of Common Coupling (PCC). Microgrids can operate in isolated mode, where the microgrid is disconnected from the distribution network and depends only on its local generation, or in grid-connected mode, where the upstream grid can participate in supplying the microgrid's demand. A typical microgrid structure is shown in Figure 2-1 [8].

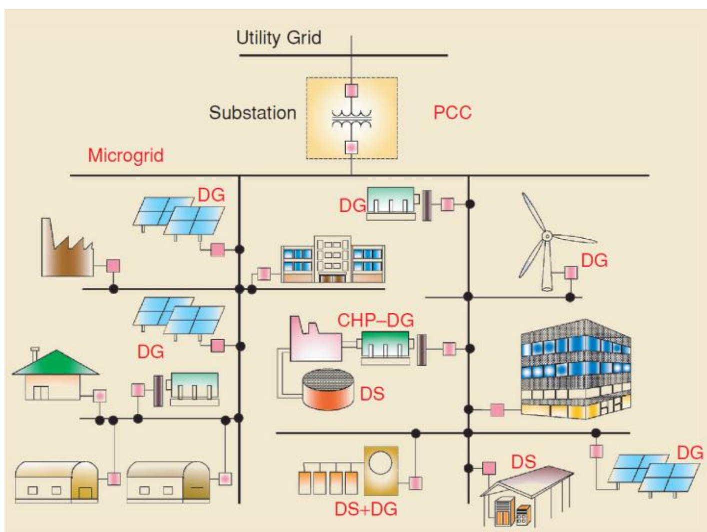

Figure 2-1: A typical microgrid structure [8]

Microgrids are considered to be efficient because they allow for a higher penetration level of renewable resources. They are also considered to be resilient due to their ability to maintain power supply when faults occur in the upstream grid [7]. At the same time, the implementation of microgrids faces several challenges. Controlling multiple generators and loads to meet the demand requirements and to maintain the microgrid’s stability without exceeding any of the operating limits is a complex task [7]. Furthermore, the integration of renewable resource raises several technical issues such as generation intermittencies, load mismatches, and voltage instabilities [3].

A microgrid has an Energy Management System (EMS) that is responsible for optimizing the microgrid’s operation during isolated and grid-connected mode. EMS performs demand and renewable power forecasting, schedules the generation of dispatchable units, controls the power exchange with the upstream grid, and carries out demand side management and security assessments. Moreover, EMS stabilizes the microgrid and maintains its voltage and frequency levels during transition conditions between different modes of operation [9], [10].

2.2.2 Generation scheduling in microgrids

The scheduling of generators in a microgrid has several differences from the case of a large power system. The size of the dispatchable units in a microgrid is much smaller than large power systems. The reduction in the size reflects an easier switching operation which results in a more flexible scheduling problem [2]. The reduction in the size also affects the ramping rates and the minimum up and down time limits. Generation scheduling in microgrids requires more decisions to be taken such as the power exchange with the upstream grid and the charging and discharging of energy storage systems. Furthermore, the operation of microgrids during isolated mode is a challenging task due to the limited resources available to meet the demand and the reserve requirement. Moreover, a higher penetration level of renewable generators is permitted in microgrids compared to large power systems. As a result, the intermittency of renewable generators will have a more significant effect.

Since the concept of the microgrid is still relatively new, standards on microgrid integration and operation are still under development [7]. Different policies were presented in the literature to solve the generation scheduling problem. However, the majority of the previous studies considered one of the following two policies: minimizing the expenses, or maximizing the profit [3], [9], [10]. The first policy tries to minimize the total expenses of the microgrid which includes the operating cost of the local generators and the cost of the power supplied by the upstream grid. On the other hand, the second policy tries to maximize the profit from the power exchange with the upstream grid. Profit is the difference between the microgrid’s revenue and expenses where the revenue is equal to the amount paid by the microgrid’s customer and the cost of the excess power supplied to the upstream grid. Examples of other policies include maximizing the use of renewable generators, minimizing gas emissions, and minimizing power imports from the upstream grid [10].

Scheduling the power generation in a microgrid can significantly benefit its performance and maximize the resources utilization. Therefore, several recent research articles have discussed the topic of optimal generation scheduling in microgrids [3], [9], [10], [11].

Basu et al. [11] presented a planned scheduling model for the economic dispatch problem in a combined heat and power (CHP) based microgrid. Optimal locations, sizes, and types of distributed energy resources (DERs) were first selected considering minimum power losses as the objective function. Economic power sharing between a mix of DERs was then performed using differential evolution while satisfying all the constraints. However, the work presented in [11] did not consider any type of renewable resources and studied the system only during the grid-connected mode. Furthermore, the applied optimization technique, i.e. differential evolution, is a meta-heuristic technique that cannot guarantee an optimal solution.

Tsikalakis and Hatziargyriou [9] studied the operation of a central controller used to optimize the operation of a microgrid during grid-connected mode. Two market policies were analyzed: minimizing the expenses, and maximizing the revenue. The authors solved the day-ahead unit commitment problem using priority list, and the economic dispatch problem using sequential quadratic programming. No attempt was made to study the microgrid in the isolated mode. Furthermore, uncertainties due to forecasting errors were not tackled in the model formulation.

Logenthiran et al. [10] proposed a multi-agent system for the real time operation of a microgrid including generation scheduling and demand side management. Generation scheduling was performed using a two-stage process that included day-ahead and real time scheduling. A real time digital simulator (RTDS) was used to model the operation of a microgrid in real time. RTDS provided the feedback needed to perform the real time scheduling. Computational intelligence techniques such as Genetic Algorithm (GA) were applied in the decision making modules. However, in spite of their near optimal performance, these techniques cannot guarantee an optimal solution.

Chen et al. [3] proposed a new method to size the energy storage systems (ESS) in a microgrid. The day-ahead unit commitment problem was used to facilitate the proposed method in grid-connected and isolated mode. Load and renewable power forecasting errors were taken into consideration by increasing the required amount of spinning reserve. The discharge efficiency of ESS was also included in the reserve criteria. In spite of the additional reserve, the proposed unit commitment formulation remained deterministic. The authors did not consider multi-scenario stochastic models that could have covered a wider spectrum of uncertainties.

2.3 Handling uncertainties

The main objective behind solving the day-ahead unit commitment problem is to schedule the power generation in a system in order to meet the demand and the reserve requirement at a minimum operating cost. However, if uncertainties are present in the problem, the obtained solution might not be optimal or even feasible. Therefore, it is highly significant to consider the uncertainties when solving the day-ahead unit commitment problem. A large and growing body of literature has investigated the integration of uncertainties in the unit commitment problem. There are two main approaches presented in the literature to handle uncertainties: additional reserve requirement [3], [12]-[19], and multi-scenario stochastic models [12], [20], [22]. While uncertainties are modeled implicitly in the first approach, the second approach considers multiple scenarios for the load and renewable power generation, and therefore the uncertainties are explicitly represented [20]. This section will first review the sources and effects of uncertainties. Then, a thorough literature review on each of the two approaches will be presented.

2.3.1 Sources and effects of uncertainties

In the classical unit commitment problem, one of the main causes of uncertainties was the unexpected variations in the system's demand during the day. The integration of intermittent renewable resources in the system introduces similar uncertainties that can cause significant challenges to the unit commitment problem. These uncertainties are not due to the continuous variations in the renewable power generation, but due to the partial unpredictability of the wind and solar power because of their forecasting errors. Practical wind power forecasting tools still suffer from a mean absolute error of 10% on average for day-ahead forecasts [22]. The effects of uncertainties associated with the renewable generators are more significant in the case of a microgrid due to the high penetration level. Moreover, the effects of uncertainties increase as the size of the microgrid decreases [9].

Another source of uncertainties in the classical unit commitment problem is the outage of generation units. Dispatchable generation units might fail to generate power as scheduled which causes a power shortage in the system. This shortage can be met using the spinning reserve which is equal to the unused capacity of the other committed units. Similarly in a microgrid, unit outages contribute to the uncertainty in the unit commitment problem. However, a major outage that a microgrid might experience is the disconnection from the upstream grid. In that case, the microgrid is isolated from the rest of the network and is supposed to supply the entire demand with adequate reserve using only its local generators.

Large penetration of plug-in electric vehicles (PEV) and large-scale demand response are to be supported in the envisioned future smart grid [22]. This will also present new uncertainties in the unit commitment problem that can cause negative effects on the system's operation. Therefore, it is highly important to evaluate these potential problems beforehand in order to find solutions to mitigate them.

Unexpected variations in the renewable generation along with demand forecasting errors and possible unit outages can cause power unbalance in addition to serious reliability risks in the system. Furthermore, the presence of these uncertainties could require the use of costly balancing services which increases the total operating cost of the system [23]. Figure 2-2 [24] shows the technical issues that might rise during planning and operation processes due to uncertainties introduced by renewable generators. Four different time frames are shown in the figure; each corresponds to a different process. The first time frame describes the process of resource and capacity planning in which planners study the system over several years to determine the infrastructure requirements. The process is affected by the long term load growth forecasting errors and incorrect evaluation of the installed capacity (ICAP) and the effective capacity (UCAP). The next time frame, which is in the range of one day, shows the process of unit commitment which experience uncertainties due to the day-ahead forecasting errors. The process of load following is shown in the next time frame. This process takes place during the day to modify the generation on an hour-to-hour or minute-to-minute basis according to the variations in the load and renewable generation. This process is affected by uncertainties due to hour-ahead forecasting errors. In the last time frame, frequency and tie-line regulation processes are performed on a cycle-to-cycle or second-to-second basis. Uncertainties due to variations in renewable generators' output power are handled by automated controls [24].

2.3.2 Additional reserve requirement

When solving the unit commitment problem, system operators schedule extra capacity than the forecasted load to be used if needed. The excess capacity is called the operating reserve. The operating reserve consists of spinning and non-spinning reserve, where spinning reserve is provided by online units, and non-spinning reserve is provided by fast starting units or by interruptible loads [20]. Spinning reserve is essential to respond to sudden generation outages and to unexpected fluctuations in the load. The classical unit commitment problem has a constraint that guarantees a certain amount of spinning reserve at any time period during the day. This amount is traditionally selected as a deterministic value that is equal to the capacity of the largest online unit [12], [17] or equal to a certain percentage of the load [14], [19]. However, the penetration of renewable resources in the system increases the power fluctuations due to the intermittent nature of renewable generators. Therefore, larger amounts of spinning reserve must be committed to cater the forecasting errors of renewable power and to maintain the system's reliability [3], [12], [13].

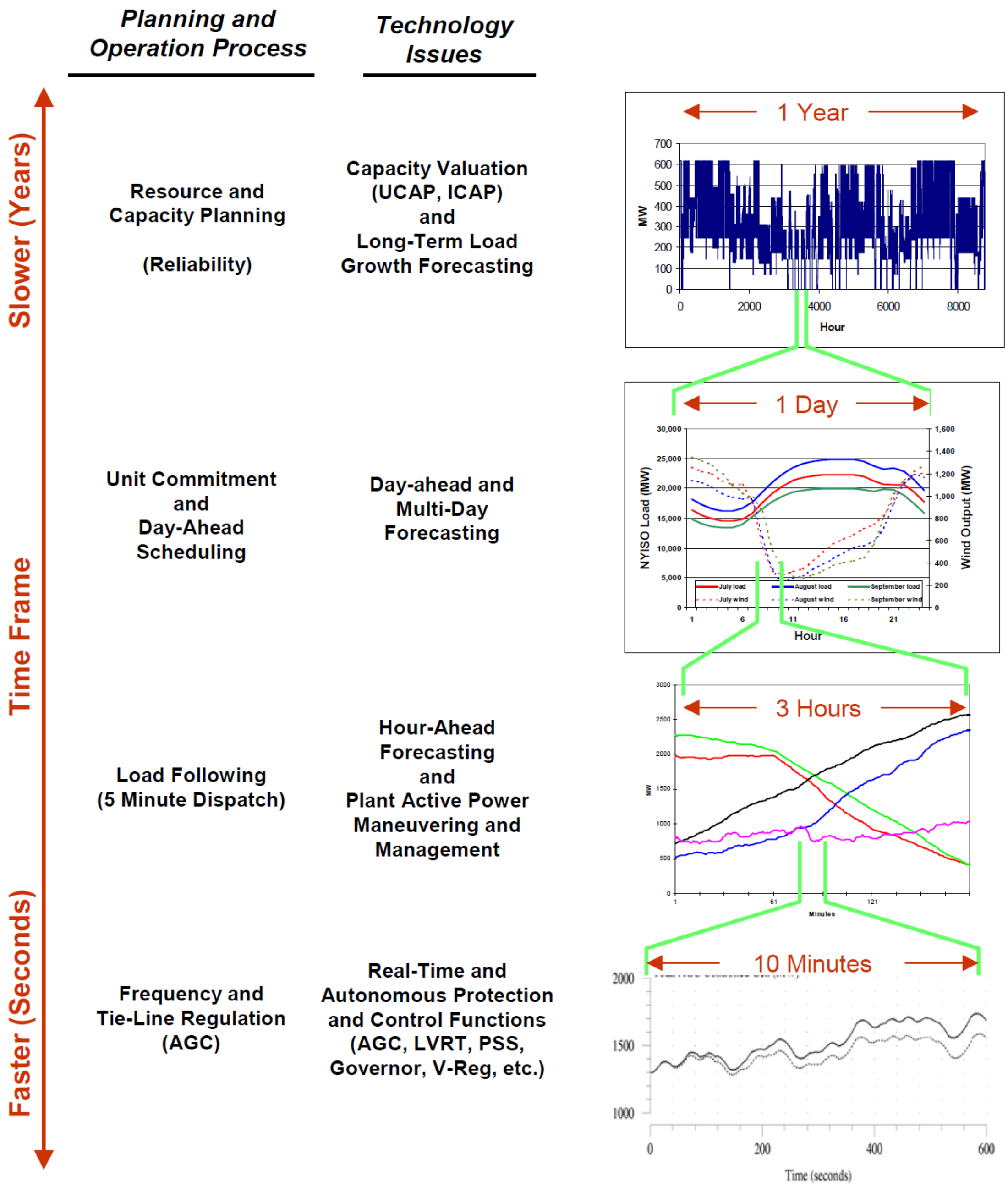

Figure 2-2: System's planning and operation processes and their technical issues [24]

(UCAP: The effective capacity, ICAP: The installed capacity, AGC: Automatic generation control, LVRT: Low voltage ride through, PSS: Power system stabilizer, V-Reg: Voltage regulator)

Chen et. al. [3] included an additional reserve to tackle the load and renewable power forecasting errors. The amount of additional reserve was selected based on the forecasting errors of each forecasting tool. For wind energy, wind speed forecasting error was represented using the root mean square error (RMSE) of the time series model used to forecast the wind speed. Similarly, the mean absolute percentage error (MAPE) was used to represent the error between the actual and the forecasted solar radiation. Errors in load forecasting were simply represented as a percentage of the total load. Similar practice was followed in [14] to handle the wind forecasting errors.

Doherty and O'Malley [13] presented a new approach to quantify the reserve demand in a system that has a high penetration of wind power. Generators' outage rates, and load and wind power forecasting errors were considered in this method. The presented methodology relates the reserve requirement at each hour to the reliability of the system over a year. The reserve is allocated such that the average risk of having a load shedding during each hour is kept the same for all the hours throughout the year. It was concluded that the reserve amount must be increased when wind penetration increases. Otherwise, the system might witness a significant decrease in the reliability. This method was applied in [12] to handle the wind power forecasting errors. It was found that if the unit commitment problem was resolved during the day, more accurate estimations of the load and wind power would be obtained. Therefore, the required spinning reserve could be allocated more properly. Furthermore, increasing the frequency of resolving the unit commitment problem reduces the reserve requirement due to obtaining more accurate forecasts.

Albadi [16] proposed stochastic criteria instead of the traditional deterministic criteria to select the spinning reserve requirement. The proposed criteria were based on the probabilistic confidence level of meeting the expected demand. A chance-constrained stochastic formulation was used to represent the stochastic constraints. In order to maintain the deterministic formulation of the unit commitment problem, the stochastic constraints were converted into equivalent deterministic constraints based on predetermined confidence levels. However, the values of the confidence levels were selected based on operator's experience which is the main weakness of this approach.

One major drawback of the previous three approaches is the possibility of over scheduling the spinning reserve. Although these approaches might be able to estimate the required reserve amount to cater sudden changes in the load and renewable power, the provided solution is not necessarily optimal. This could result in a higher reserve cost, and therefore increase the total operating cost of the system. At the same time, under-scheduling the spinning reserve causes reliability risks in the system leading to possible load shedding in the case of contingencies [15]. As a result, there has been an increasing amount of literature on techniques to optimally estimate the spinning reserve requirement in systems with significant renewable power penetration.

Ortega-Vazquez and Kirschen [17] introduced an approach to optimize the spinning reserve requirement using a cost/benefit analysis. The authors defined the optimal spinning reserve as the amount at which the cost of supplying one extra MW of reserve equals to the benefit of supplying that extra MW. The benefit of reserve is measured in terms of the reduction in the expected cost of interruptions. The proposed method was expanded in [18] by the same authors to the case of a system with significant wind power penetration. It was stated that in order to obtain an ideal solution, the unit commitment and the reserve estimation problems have to be solved simultaneously. This, however, is a very challenging task. The main difficulties lie in incorporating the stochastic nature of the load and the renewable power in addition to accounting for the units' unreliability through the calculation of the expected energy not served (EENS) and the loss of load probability (LOLP). To overcome these difficulties, the proposed method decouples the optimization of the spinning reserve requirement from the unit commitment problem. Furthermore, unlike the unit commitment problem, inter-temporal couplings are not considered when optimizing the spinning reserve requirement. In other words, it is solved separately for each time period in the scheduling horizon considering one time period at a time. This was done to reduce the computational burden of the problem. The method can be classified as a bi-level optimization problem [25]. One of the limitations of this method is that the preprocessing of the spinning reserve requirement before solving the unit commitment problem can lead to suboptimal solutions.

Wang and Gooi [19] have overcome this drawback by proposing a multi-step probabilistic method that simultaneously solves the spinning reserve estimation and the unit commitment problem. Uncertainties due to forecasting errors of load, wind power, and solar power are aggregated together and integrated into the problem. Furthermore, linear formulations for the EENS and LOLP calculations are included into the problem. However, unit outage events suffer from combinatorial characteristics that make the calculation of EENS and LOLP computationally complex, especially for the second and higher order outage events. Such calculations are traditionally performed by generating a capacity outage probability table (COPT) as described in [26]. However, this would work only if the units' status and power outputs are known. Therefore, the authors proposed a multi-step iterative method that can efficiently estimate the EENS and LOLP values. The EENS and LOLP of the first order outage events are calculated within the optimization problem. A new COPT is generated after each step and used in the following step to calculate the EENS and LOLP of the second and higher order outage events. The method keeps iterating until a convergence criterion is satisfied.

2.3.3 Multi-scenario stochastic models

The traditional unit commitment problem is formulated as a deterministic problem in which all the parameters are known. This is justified for a system with no renewable generators, where the main source of uncertainties is the load forecasting error. Daily load profiles have a high repetitive nature, and therefore load forecasting is generally assumed to be accurate [13]. However, once renewable generators are integrated in the system, forecast uncertainties cannot be ignored and must be considered to achieve a reliable solution. Adding additional amounts of spinning reserve can help in mitigating the effects of unexpected fluctuations in the load and renewable power. Similarly, integrating these uncertainties in the unit commitment formulation can help in generating more robust and flexible commitment schedules. This can be done using a stochastic formulation instead of the classical deterministic formulation. To achieve that, forecasting errors need to be accurately modeled in order to integrate them in the unit commitment formulation. In recent years, there has been an increasing amount of literature applying stochastic models to solve the unit commitment problem [12], [19], [20], [27].

2.3.3.1 Uncertainty modeling and scenario generation

The uncertain parameters in the unit commitment problem are the load and the renewable power generation. Their uncertainty is modeled by adding an error term to each of the forecasted values [20]. The error term represents the possible deviations from the forecasted value. The error is assumed to be a random variable that follows a certain probabilistic distribution that is derived from the historical data of the load or the renewable power generation [13], [18], [23], [27], [28]. Distribution fitting method can be used to derive the probability distribution function (PDF) of the forecasting error. This method assumes that the forecasting error follows a standard probability distribution such as the normal distribution and finds its parameters using a fitting procedure [23]. Alternatively, empirical distribution method can be used when the available data doesn't follow any standard probability distribution [23]. The distribution of the random variable in most stochastic optimization studies is assumed to be known from the forecasting models [29]. The parameters of the probability distribution function might vary from one forecasting tool to the other and are affected by the forecasting horizon, the type of the generator, the geographical location, and the spatial distribution [27], [30].

The scenarios are generated by constructing a multi-stage scenario tree model. Since the error PDFs are continuous, infinite number of scenarios can be generated. Therefore, methods such as Monte Carlo simulation [12], [28] are usually used to create the scenarios of the load and renewable power generation. Instead, the forecasting error PDF can be discretized into a finite number of samples. These samples represent the discrete probability distribution of the forecasting error and can be used to generate a finite number of scenarios [14], [19]. The number of samples in the discrete PDFs determines the number of branches at each new stage in the scenario tree model. Figure 2-3 shows an example of a two-stage and a multi-stage scenario tree model. In a two stage model, the scenarios are generated at the first time period and then repeated for the rest of the scheduling horizon. On the other hand, a multi-stage model generates new scenarios at each time period. Therefore, an overwhelming amount of scenarios are generated [31]. For instance, if the PDFs of the load, wind power, and solar power forecasting errors were each discretized into five samples, the number of new scenarios generated by each node at each time period is equal to 125 scenarios. Considering a scheduling horizon of 24 hours, the total number of scenarios generated is going to be equal to 125^{24}. This huge number of scenarios is unpractical and computationally expensive. Therefore, scenario reduction techniques are usually used to select a smaller number of scenarios with high relative accuracy [14].

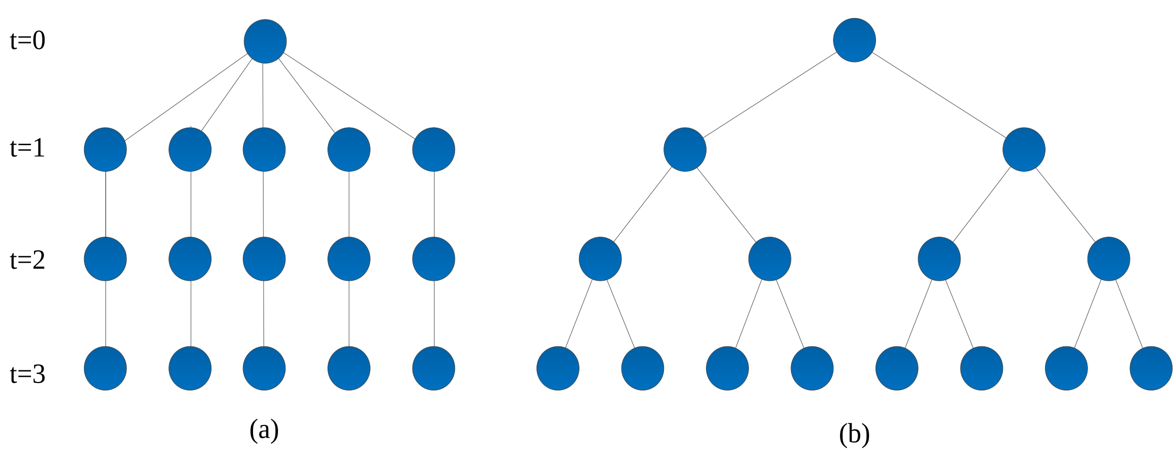

Figure 2-3: Scenario tree: a) Two-stage, b) Multi-stage

2.3.3.2 Stochastic models

The most complete formulation of the unit commitment problem is done through full stochastic models that are known in the literature as stochastic programs with recourse [21]. These models use an explicit representation of the uncertainties in the problem formulation. Stochastic programs have a multi-stage decision framework that provides the ability to update the decisions once the uncertainties are realized [20]. The simplest framework is a two-stage stochastic program. An initial decision is taken during the first stage; however, due to random events, the outcome of that stage might vary. Therefore, a recourse corrective decision can be made in the second stage when the random events are realized.

Ruiz et al. [20] proposed a two-stage stochastic program to solve the unit commitment problem. The unit commitment variables were considered to be stage one decisions, while power output and reserve requirement were considered to be stage two decisions. The authors pointed out that earlier studies on stochastic unit commitment dropped the reserve requirement constraint because the reserve was already taken into consideration by considering multiple scenarios. However, the authors argue that the few scenarios considered cannot cover the entire spectrum of uncertainties. Several study cases were performed to show the superiority of combining stochastic formulation with additional reserve requirement over the other uncertainty handling techniques. The only limitation in this work is that renewable generators were not included. Only unit outage events and load uncertainty were taken into consideration. The scenarios were manually selected to represent the extreme cases such as the outage of the largest unit and the maximum deviation from load forecast. The authors emphasized on the importance of modeling all the significant sources of uncertainty in order to achieve better improvements over a deterministic formulation.

A three-stage stochastic program with rolling planning was proposed by Tuohy et. al. in [12]. This was part of the Wind Power Integration in Liberalised Electricity Markets (WILMAR) model [32]. The model consist of two parts: the scenario tree tool that generates the scenarios, and the scheduling model that solves the unit commitment problem. A rolling planning model, shown in Figure 2-4 [12], is considered such that a new day-ahead schedule is prepared every day at noon with a horizon of 36 hours. The scheduling process is repeated every 3 hours taking into account the day-ahead schedule. The intra-day scheduling includes not only the power output levels, but also the unit commitment decisions. The first stage considers the forecast to be perfect, and therefore it uses a “hear-and-now” approach when taking its decisions. On the other hand, the remaining two stages take decisions through "wait-and-see" approach since uncertainties are not yet realized and might vary during future planning periods.

Although stochastic formulations introduce a better representation of the uncertainties than deterministic formulations, they still suffer from the dimensionality curse that can make the solution computationally intractable even with scenario reduction techniques [21]. However, two-stage linear stochastic programs can be represented using multi-scenario linear optimization models which are considered to be the equivalent deterministic models of the stochastic programs [33]. In unit commitment problem, the objective function of a multi-scenario optimization model equals to the summation of the product of the operating cost of each scenario and its corresponding probability. At the same time, the constraints of the original deterministic single-scenario model are duplicated for each scenario in the multi-scenario optimization model. The size of the problem depends on the number of scenarios considered. The problem can still be formulated as a mixed integer linear program, and therefore it can be solved using the available efficient optimization packages. Another drawback in stochastic programs is that they are not suitable for production level in contrast to mixed integer linear programs which have been recently adapted in industrial standards [34].

Saber and Venayagamoorthy [27] formulated the unit commitment problem as a multi-scenario linear optimization problem. The uncertainties associated with load, wind power, solar power, and plug-in vehicles were considered in this work. However, the problem was solved using particle swarm optimization which is a meta-heuristic technique that cannot guarantee an optimal solution. Similarly, Wang and Gooi [19] integrated the uncertainties in the unit commitment problem using a multi-scenario optimization model. To limit the size of the problem, the number of scenarios was reduced by aggregating the forecasting errors into one distribution function. The problem was formulated as a MILP and solved using CPLEX solver [35].

2.4 Discussion

The main objective of this thesis is to study the day-ahead unit commitment problem in microgrids that are facing uncertainties in power generation. Therefore, this section has summarized three major related topics: the classical unit commitment problem, microgrids, and uncertainty handling techniques. Several research articles on scheduling generation in microgrids were reviewed. The major limitation in most of these studies was not considering effective techniques to handle uncertainties. Furthermore, isolated mode was rarely studied, while grid-connected mode was usually considered alone. Another criticism was the use of heuristic methods instead of mathematical programming methods to solve the scheduling problem which might result in suboptimal solutions.

Moreover, this section has briefly presented the sources of uncertainties and their effects on the system's operation. It also discussed the main two techniques presented in the literature to handle uncertainties in the classical unit commitment problem: additional reserve requirement, and multi-scenario stochastic models. Recent studies that applied these techniques were investigated and summarized. It was reported that applying both techniques together can help in covering a wider range of uncertainties, and therefore producing a more reliable and robust solution.

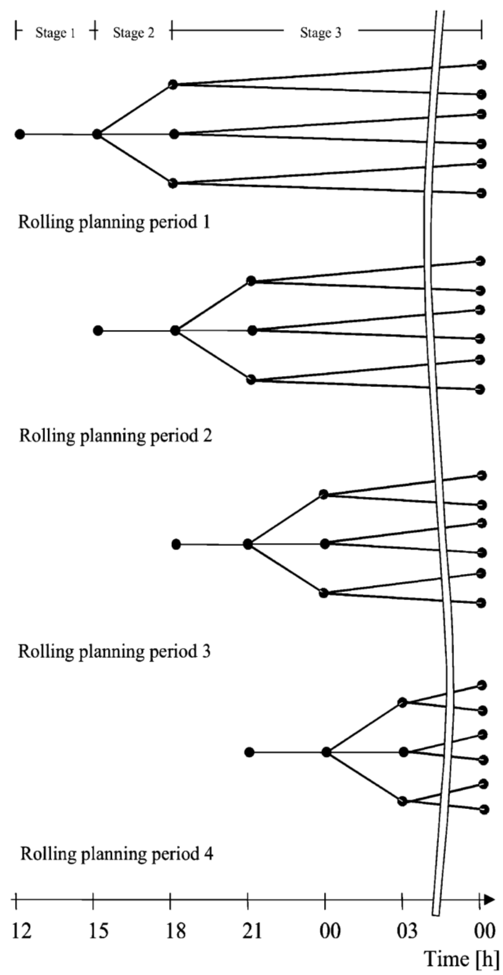

Figure 2-4: Rolling planning and scenario trees [12]

Chapter 3
Day-ahead Unit Commitment Problem in Microgrids

3.1 Introduction

The day-ahead unit commitment problem is a vital process that is necessary to guarantee the economical provision of electrical power to the system's loads. This process is also essential for the stability and the adequacy of the system and can help in maximizing the utilization of the available resources. In microgrids, the day-ahead unit commitment problem has a higher significance due to the additional uncertainties that exist in the system. The uncertainties are present because of the high penetration of renewable resources and the possibility of disconnection from the upstream grid. This chapter will discuss the day-ahead unit commitment problem for microgrids operating in grid-connected and isolated mode. The problem should find an optimal scheduling solution for the dispatchable generators inside the microgrid such that the electrical demand is met with adequate reserve at any time period during the next 24 hours. Two different optimization models will be proposed; one for each mode of operation. The proposed models will integrate uncertainty handling techniques to mitigate the effects of uncertainties on the microgrid's operation.

There are different policies and objectives considered in the literature when optimizing the operation of microgrids. The objective of the optimization models presented in this thesis is to operate the microgrid economically during both modes of operation by minimizing the total expenses. The microgrid system understudy has a mix of dispatchable and non-dispatchable electrical generators supplying a group of electrical loads. Gas and diesel generators are considered as dispatchable generators, while wind turbines and Photovoltaic (PV) systems are used as non-dispatchable renewable generators. The loads are divided into critical and non-critical loads. Critical loads, such as hospitals, must be provided with an adequate reserve at all times in order to maintain their power supply. Thermal demand is not considered, and therefore none of the generators is supplying heat. It is assumed that all the generators are operating at unity power factor; thus, no reactive power is produced, nor needed in the system. The microgrid is connected to the upstream grid at a single point of common coupling where the capacity of the line linking the two grids determines the limit of the power exchange between them. It is also considered that the microgrid has to accommodate all the local renewable power generation. Therefore, the amount of power that should be supplied by the local dispatchable units at each time period is equal to the total system's demand minus the renewable power generation at the same time period. This amount is referred to as the net demand. Incentive programs, such as Feed-in Tariff (FiT) that is implemented in Ontario, offer similar privileges to the renewable generators' owners [36]. Nevertheless, power curtailment might be indispensable in the case of power unbalances in the system.

The operation of a microgrid during both modes of operation will be first reviewed. After that, the applied uncertainty handling techniques will be presented. Moreover, the formulations of the two proposed models for the day-ahead unit commitment problem are going to be discussed. One model is for a microgrid operating in grid-connected mode, and the other is for a microgrid operating in isolated mode.

3.2 Modes of operation

3.2.1 Grid-connected mode

In this mode, the upstream grid is connected to the microgrid and power exchange is allowed. The upstream grid can participate in providing power and spinning reserve to the microgrid [3]. The day-ahead unit commitment problem should minimize the total expenses of operating the microgrid in grid-connected mode for a scheduling horizon of 24 hours. The total expenses consist of the local generators' operating cost, the cost of the power imported from the upstream grid, and the cost of providing the spinning reserve.

The upstream grid can be considered as a bidirectional virtual generator that is committed to the microgrid as long as it is operating in grid-connected mode [3], [9], [11], [19]. The virtual generator produces a positive power when the power is imported from the upstream grid, and a negative power when the power is exported to the upstream grid [3]. The virtual generator has a minimum power supply limit of zero and a maximum limit equal to the capacity of the line linking the upstream grid and the microgrid. Furthermore, unlike regular generators, the virtual generator is not bounded by any ramping or minimum up or down time limits. It has to be noted, however, that this assumption might not be true in reality. The power imported from the upstream grid must be supplied by other generators in the upstream grid that are constrained by a set of operational limits. Nevertheless, the assumption can be justified by the fact that the generators in large power systems have a much higher capacity, tens to hundreds of megawatts, compared to the virtual generator capacity, hundreds of kilowatts to few megawatts. Therefore, large power system generators should be capable of providing the required power whenever it is needed.

The virtual generator is assumed to generate power at a higher cost compared to the other dispatchable units inside the microgrid. This assumption makes the microgrid depends mainly on its local generators to supply the local loads. The upstream grid is utilized in cases of emergencies and when it becomes a more economical alternative than the local dispatchable generators. This could happen in cases when expensive start-up cost is required or if the dispatchable units are limited by minimum up and down time limits. It is worth mentioning that the day-ahead unit commitment problem is an inter-temporal process that takes into account the past and future time periods and does not solve for each time period separately. Therefore, constraints such as the minimum up and down time limits have a significant effect on the microgrid's expenses.

The operation of a microgrid in grid-connected mode can be summarized in the following three cases:

1) Normal operation:

In this case, the demand can be easily supplied by the local generators. The power available from the renewable generators is first used to supply the demand. The rest of the demand is supplied by the dispatchable generators. The upstream grid is connected but neither supplying nor receiving any power. Spinning reserve requirement is provided by the committed dispatchable units and the upstream grid. The amount of spinning reserve provided by each committed dispatchable unit is equal to its capacity minus the amount of power generated by that unit.

2) Excess demand:

In this case, the demand exceeds the capacity of the renewable and dispatchable generators. Therefore, the upstream grid supplies the excess demand. The spinning reserve is provided by the remaining capacity of the upstream grid.

3) Excess renewable generation:

In this case, the entire demand can be supplied by the renewable generators and any excess power is exported to the upstream grid. Therefore, none of the dispatchable units have to be committed. The spinning reserve is provided by the upstream grid.

The interconnection with the upstream grid provides the microgrid with a larger capacity that can result in a smooth and robust operation. Another significant importance is the provision of the spinning reserve. The upstream grid can supply most if not all of the required spinning reserve.

Therefore, the utilization of the local dispatchable generators can be maximized. Thus, it is expected that operating the microgrid in the grid-connected mode will result in lower expenses compared to the isolated mode. Figure 3-1 summarizes the operation of the microgrid in grid-connected mode during the three cases under study.

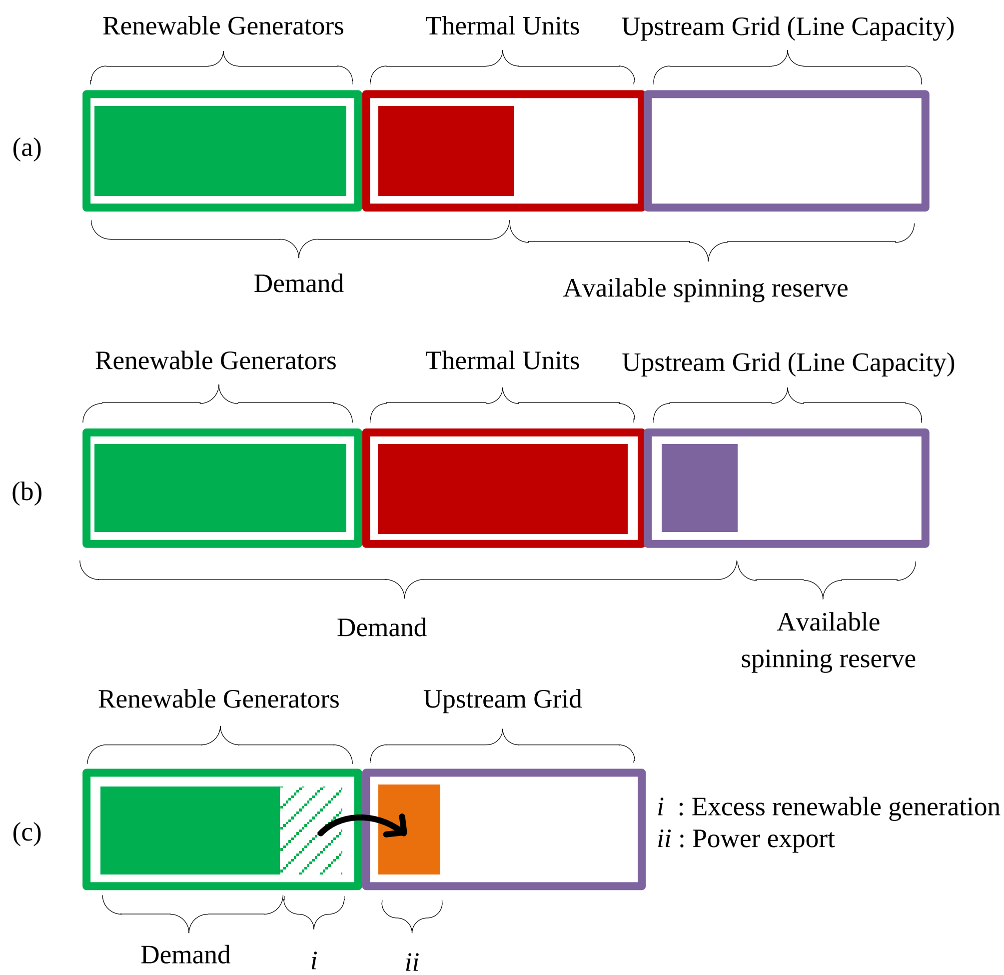

Figure 3-1: Microgrid operation during grid-connected mode: a) Normal operation, b) Excess demand, c) Excess renewable generation

3.2.2 Isolated mode

In this mode, the microgrid is isolated from the rest of the network and disconnected at the point of common coupling. The only sources of power supply available to the microgrid are the local dispatchable and renewable power generators. Due to their intermittent nature, renewable generators cannot participate in supplying the spinning reserve. Therefore, spinning reserve is provided only by the dispatchable generators. To limit the spinning reserve requirement and due to the lack of reserve resources, the spinning reserve requirement is estimated only for the critical loads. To ensure problem feasibility, load shedding and power curtailment are considered as two expensive measures that can be taken to preserve the system's power balance. However, these two measures are performed only if it is necessary to do so. The day-ahead unit commitment problem should minimize the total expenses of operating the microgrid in isolated mode for a scheduling horizon of 24 hours. The total expenses consist of the local generators' operating cost, the cost of performing load shedding and power curtailment, and the cost of providing the spinning reserve.

The operation of a microgrid in the isolated mode can be summarized in the following three cases:

1) Normal operation:

In this case, the demand can be easily supplied by the local generators. All the available renewable power is first accommodated. Any remaining demand is then supplied by the dispatchable generators. The unused capacity of the committed dispatchable units provides the spinning reserve.

2) Excess demand:

In this case, the demand exceeds the capacity of both renewable and dispatchable generators. Therefore, the excess demand must be shed in order to preserve the power balance in the system. Since the microgrid is isolated from the upstream grid, the entire spinning reserve requirement has to be supplied by the local dispatchable generators. Therefore, an extra load shedding has to be performed in order to free a portion of the dispatchable units' capacity to provide the required spinning reserve. The spinning reserve is provided only to the critical loads and the load shedding is performed only over the non-critical loads.

3) Excess renewable generation:

In this case, the entire demand can be supplied by the renewable generators and any excess renewable power has to be curtailed. However, providing spinning reserve to the critical loads requires committing at least one dispatchable unit with enough capacity to cover the reserve requirement. It is important to mention that once a dispatchable unit is committed, it has to generate a minimum power of P_{min}. Therefore, an additional renewable power curtailment that is equal to the value of P_{min} has to take place in order to maintain the power balance in the system.

Figure 3-2 summarizes the operation of the microgrid in the isolated mode during the three cases under study.

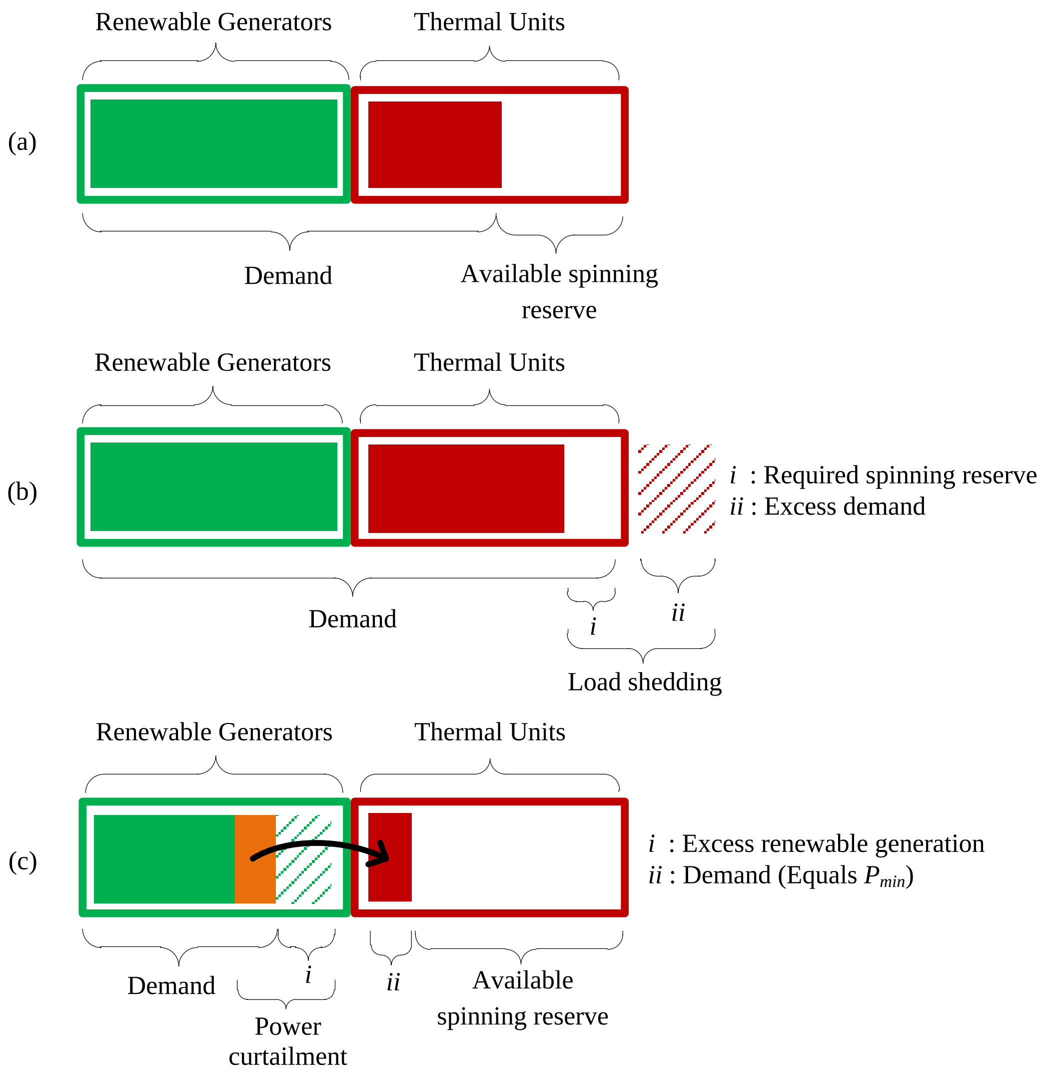

Figure 3-2: Microgrid operation during isolated mode: a) Normal operation, b) Excess demand, c) Excess renewable generation

Due to the disconnection from the upstream grid, the operation of a microgrid in the isolated mode is more challenging and costly than in the grid-connected mode. The microgrid has to depend only on its local generators to meet the system's demand and reserve requirement. This, as a result, forces the microgrid to apply expensive procedures to maintain the system's power balance. Therefore, the expenses are expected to be higher than the case of grid-connected mode.

It is worth mentioning at this point that energy storage systems (ESS) can provide an alternative source of spinning reserve. Therefore, they can significantly reduce load shedding and power curtailment, and thus reduce the expenses of the microgrid. According to the results shown in [3], energy storage systems can store the surplus renewable power which results in a partial dispatchable behavior by the intermittent generators. As a result, the dispatchable units will have a smoother operation with less switching actions; thus, lower operating cost. However, energy storage systems have a high initial cost and their allocation and sizing is considered to be a challenging problem [7], [37]. Energy storage systems are not considered in this study, but are highly recommended for future work.

3.3 Uncertainty handling techniques

At the microgrid scale, the effects of uncertainties are more severe. The high penetration of renewable generators causes higher uncertainties in the system due to the forecasting errors. These uncertainties can cause a sudden loss of load due to unexpected shortage in the power supply. They can also cause higher costs than the ones estimated by the day-ahead unit commitment problem due to the expensive balancing measures that need to be taken. To mitigate the effects of forecasting errors and for a better assessment of the system's requirements, two uncertainty handling techniques are going to be integrated into the day-ahead unit commitment models: additional reserve requirement, and multi-scenario stochastic models. Additional reserve requirement can help in mitigating the effects of uncertainties by providing additional reserve that can respond to unexpected deviations in the power generation. At the same time, multi-scenario stochastic models can provide a better commitment solution that satisfies the system constraints during several uncertainty scenarios. Applying the former method alone cannot capture the entire range of uncertainties that are affecting the problem. It is important to note that uncertainties due to unit outages and disconnection from the upstream grid will not be considered in the proposed models and are left for future work.

3.3.1 Additional reserve requirement

In microgrids, allocating additional reserve can help in accommodating the volatility of renewable power generators, and can provide additional reserve for other microgrids available in the distribution system [2]. Spinning reserve can be provided to a microgrid using local dispatchable generators, load management, upstream grid, and energy storage systems. Committed dispatchable units can provide their unused capacity as a spinning reserve. On the other hand, offline units can be considered as a source of non-spinning reserve [2]. Load management procedures such as load shedding can free a portion of the dispatchable units capacities to provide the required reserve [38]. In grid-connected mode, the upstream grid can participate like any other committed unit in supplying the spinning reserve [11]. Similarly, energy storage systems can provide fast spinning reserve that is equal to the available storage. Furthermore, it is reported in [2] that renewable generators can provide an amount of spinning reserve equal to the difference between the maximum available power and the actual power delivered. In this research, only local dispatchable generators, upstream grid, and load management are going to be considered as sources of spinning reserve. Energy storage is not included in the system understudy, and renewable generators are assumed to be operating at their maximum available power at all times.

There are several options reported in the literature to select the spinning reserve requirement in microgrids. The reserve is usually selected deterministically such that it can cover the outage of the largest committed dispatchable unit, or cover the largest load that could be connected to the system, or cover a certain amount of the system's total demand [2]. Few studies have suggested that the reserve cost cannot be negligible, and thus the system should operate at the optimal reserve requirement. Optimizing the reserve requirement, however, is a computationally challenging problem.

This research will consider the reserve requirement to be equal to a percentage of the total system demand. However, to mitigate uncertainties, an additional amount determined by the forecasting error of the load and the renewable generators is added. The detailed formulation is shown in Equation (3-17). This is similar to the work presented in [3], [14], and [39]. The cost of the spinning reserve is added to the objective function. It was assumed that the cost of providing 1kW of reserve from the upstream grid or from any other dispatchable unit is the same. Therefore, during grid-connected mode, the proposed model assumes no preference regarding the source of the reserve, i.e. dispatchable units, or the upstream grid. However, it guarantees that the total available reserve from all the sources is greater than the required spinning reserve.

3.3.2 Multi-scenario stochastic model

The forecasted values consist of two main components that are added together: the expected value and the forecasting error.

$$X_f(t) = X_e(t) + e_X(t) \tag{3-1}$$

where $X_f(t)$ is the forecasted value at time t, $X_e(t)$ is the expected value (output of the forecasting tool) at time t, and $e_X(t)$ is the forecasting error at time t. The error is typically modeled as a stochastic variable that follows a certain probabilistic distribution function. Several methods were introduced in the literature to generate the load and renewable power scenarios. One common method is to discretize the probability distribution function (PDF) of the forecasting error $e_X(t)$. Load and wind power forecasting errors are usually represented using normal PDFs [13], [18]. Similarly, solar power forecasting error can be modeled as a normal PDF [27]. Each continuous PDF is discretized to create a set of finite states such that a probability is assigned to each state according to its PDF. The discrete sets of the load δ_D, wind δ_w, and solar power δ_{pv} forecasting errors are described as

$$\delta_D = \{(e_D^1, \rho_D^1), (e_D^2, \rho_D^2), .. (e_D^n, \rho_D^n)\} \tag{3-2}$$

$$\delta_w = \{(e_w^1, \rho_w^1), (e_w^2, \rho_w^2), .. (e_w^m, \rho_w^m)\} \tag{3-3}$$

$$\delta_{pv} = \{(e_{pv}^1, \rho_{pv}^1), (e_{pv}^2, \rho_{pv}^2), .. (e_{pv}^q, \rho_{pv}^q)\} \tag{3-4}$$

where e_D^i is the error of the i^{th} state in the load forecasting error PDF, ρ_D^i is the corresponding probability of that state, and n is the total number of states in the discrete set [27]. The discrete sets of wind and solar power forecasting errors are defined similarly. The states' probabilities are subject to

$$\sum_{i=1}^{n} \rho_D^i = \sum_{i=1}^{m} \rho_w^i = \sum_{i=1}^{q} \rho_{pv}^i = 1 \tag{3-5}$$

The discrete sets in Equations (3-2), (3-3), and (3-4) are used to create a set of scenarios that represent the possible deviations from the load, wind power, and solar power forecasted values. Using a two-stage scenario tree that branches only at the first time period and ignores the effect of time at the remaining periods, a set of scenarios is created. The total number of scenarios equals to the product of the number of states in each discrete set. Each scenario has a probability ρ_s that is equal to the product of the probabilities of the states' corresponding to that scenario such that

$$\sum_{s=1}^{S} \rho_s = \sum_{s=1}^{S} \rho_D^s \rho_w^s \rho_{pv}^s = 1 \tag{3-6}$$

$$S = n \times m \times q \tag{3-7}$$

where S is the total number of scenarios. The created scenarios and their corresponding probabilities are used to formulate the unit commitment problem as a multi-scenario stochastic model. The unit commitment problem should find an optimal solution that satisfies all the constraints under any scenario.

3.4 Problem formulation

This section presents the formulation of two models for the day-ahead unit commitment problem in a microgrid. One model is for a microgrid operating in the grid-connected mode, and the other is for a microgrid operating in the isolated mode. The models have accommodated additional reserve requirement to cater the sudden deviations in load and renewable power generation. Furthermore, the models are formulated as a multi-scenario stochastic model to incorporate a wider spectrum of uncertainties in the problem. Both models are represented using Mixed Integer Linear Programming (MILP).

3.4.1 Grid-connected mode

In grid-connected mode, the objective function is to minimize the total expenses of the microgrid. It is stated as

$$\begin{aligned} \min \quad Z = \sum_{s=1}^{S} \rho_s \Bigg[& \sum_{k=1}^{K} \sum_{j=1}^{J} \left(C_j\left(P_{jks}\right) + SU_{jk} \right) + \sum_{k=1}^{K} \left(SRall_{ks} \times C_r \right) \\ & + \sum_{k=1}^{K} \left(P_{GIn,ks} \times C_{grid} \right) \Bigg] \end{aligned} \tag{3-8}$$

where $C_j\left(P_{jks}\right)$ and SU_{jk} are the linearized fuel cost function and the start-up cost function of unit j as described in Equation (2-3), and Equations (2-6)-(2-8), respectively. The second term is for the reserve cost, while the last term is for the cost of the power imported from the upstream grid. The problem is subject to the following set of constraints:

- System power balance

$$\sum_{j=1}^{J} P_{jks} + W_{ks} + PV_{ks} + P_{GIn,ks} - P_{GOut,ks} = D_{ks} \quad , \qquad \forall k, s \tag{3-9}$$

- Dispatchable units output limit and spinning reserve

$$P_j^{min} \leq P_{jks} \leq P_j^{max} \quad , \qquad \forall j, k, s \tag{3-10}$$

$$SRu_{jks} = \left(U_{jk} \times P_j^{max}\right) - P_{jks} \quad , \qquad \forall j, k, s \tag{3-11}$$

$$SRu_{jks} \geq 0 \quad , \qquad \forall j, k, s \tag{3-12}$$

- Upstream grid power limits and spinning reserve

$$0 \leq P_{GIn,ks} \leq P_{grid}^{max} \quad , \qquad \forall k, s \tag{3-13}$$

$$0 \leq P_{GOut,ks} \leq P_{grid}^{max} \quad , \qquad \forall k, s \tag{3-14}$$

$$SRgrid_{ks} = P_{grid}^{max} - P_{GIn,ks} \quad , \qquad \forall k, s \tag{3-15}$$

- Total available spinning reserve

$$SRall_{ks} = \sum_{j=1}^{J} SRu_{jks} + SRgrid_{ks} \quad , \qquad \forall k, s \tag{3-16}$$

- Microgrid's spinning reserve requirement

$$SRall_{ks} \geq SR_{ks} + \alpha_D.D_{ks} + \alpha_W.W_{ks} + \alpha_{PV}.PV_{ks} \quad , \qquad \forall k, s \tag{3-17}$$

The last three terms in the right hand side of Equation (3-17) are the extra reserve added to mitigate the effects of uncertainties in the load, wind power, and solar power forecast. In addition to the constraints shown in Equations (3-9)-(3-17), dispatchable units are subject to minimum up and down time constraints and logical constraints that were presented earlier in Equations (2-11) and (2-12). The ramp-up and ramp-down constraint that was shown in Equation (2-10) is modified to include to the scenarios and can be represented as

$$P_{j(k-1)s} - RR_j \leq P_{jks} \leq P_{j(k-1)s} + RR_j \quad , \qquad \forall j, k, s \tag{3-18}$$

It is worth noting that the spinning reserve constraint that was shown earlier in Equation (2-14) is updated to a more detailed formulation. It is now represented using Equation (3-11)-(3-12) and Equations (3-15)-(3-17). The new formulation clearly identifies the amount of spinning reserve provided by each dispatchable generator and by the upstream grid.

3.4.2 Isolated mode

In the isolated mode, it is also required to minimize the expenses of the microgrid; however, more attention is given to meeting the demand with stable operation. The objective function in isolated mode is stated as

$$\begin{aligned}\min \quad Z = \sum_{s=1}^{S} \rho_s \Bigg[&\sum_{k=1}^{K} \sum_{j=1}^{J} \left(C_j\left(P_{jks}\right) + SU_{jk} \right) + \sum_{k=1}^{K} \left(SRall_{ks} \times C_r \right) \\ &+ \sum_{k=1}^{K} \left(\left(P_{shed,ks} + P_{Curt,ks} \right) \times C_{DSM} \right) \Bigg]\end{aligned} \tag{3-19}$$

The second term is for the reserve cost, while the last term is for the cost of load shedding and power curtailment actions.The problem is subject to the following set of constraints:

- System power balance

$$\sum_{j=1}^{J} P_{jks} + W_{ks} + PV_{ks} + P_{shed,ks} - P_{Curt,ks} = D_{ks} \quad , \qquad \forall k, s \tag{3-20}$$

- Total available spinning reserve

$$SRall_{ks} = \sum_{j=1}^{J} SRu_{jks} \quad , \qquad \forall k, s \tag{3-21}$$

The remaining constraints are exactly similar to the grid-connected mode except for the upstream grid constraints in Equations (3-13)-(3-15) which are not applied in this mode.

In reference to the discussion in Section 3.2.2, performing load shedding and power curtailment actions during certain time periods in the isolated mode is necessary to preserve the power balance in the system and to provide the required spinning reserve. However, in order to limit these actions only to the cases when risks such as excess demand and excess renewable generation are present in the system, the following two decision variables are introduced:

$$U_{shed,ks} = \begin{cases} 1, & D_{ks} > W_{ks} + PV_{ks} + \sum_{j=1}^{J} P_j^{max} - SR_{ks} \\ 0, & otherwise \end{cases} \quad , \qquad \forall k,s \qquad \text{(3-22)}$$

$$U_{curt,ks} = \begin{cases} 1, & W_{ks} + PV_{ks} > D_{ks} - \sum_{j=1}^{J} \left(P_j^{min} \times U_{jk}\right) \\ 0, & otherwise \end{cases} \quad , \qquad \forall k,s \qquad \text{(3-23)}$$

Equation (3-22) shows the load shedding condition. Load shedding is performed in the case of an excess demand and to provide spinning reserve. Therefore, it is permitted only if the demand exceeds the available renewable generation in addition to the total capacity of the dispatchable units minus the spinning reserve requirement. Subtracting the spinning reserve requirement permits using load shedding to provide the required spinning reserve. Otherwise, load shedding would be permitted only for the excess demand. Equation (3-23) shows the power curtailment condition. If the renewable resources have an excess generation that exceeds the system's demand, power curtailment has to be performed in order to maintain the power balance. However, one or more dispatchable units have to be committed to provide the required spinning reserve. The committed units operate at a minimum power of P_{min}. Therefore, the summation of P_{min} from each committed unit is subtracted from the system's demand. The remaining amount should be supplied by the renewable resources. If the renewable generation exceeds this amount of demand, the excess power will be curtailed.

In order to keep the problem linearly formulated, the two decision variables have to be linearized. Equation (3-22) can be linearized as follows:

$$-D_{ks} + W_{ks} + PV_{ks} + \sum_{j=1}^{J} P_j^{max} - SR_{ks} \le \mu\left(1 - U_{shed,ks}\right) \ , \qquad \forall k,s \qquad \text{(3-24)}$$

$$D_{ks} - W_{ks} - PV_{ks} - \sum_{j=1}^{J} P_j^{max} + SR_{ks} \le \mu . U_{shed,ks} \ , \qquad \forall k,s \qquad \text{(3-25)}$$

$$P_{shed,ks} \le \mu . U_{shed,ks} \ , \qquad \forall k,s \qquad \text{(3-26)}$$

where μ is a sufficiently large upper bound.

Similarly, Equation (3-23) is linearized as follows:

$$-W_{ks} - PV_{ks} + D_{ks} - \sum_{j=1}^{J} \left(P_j^{min} \times U_{jk} \right) \leq \mu\left(1 - U_{curt,ks}\right) \ , \qquad \forall k, s \tag{3-27}$$

$$W_{ks} + PV_{ks} - D_{ks} + \sum_{j=1}^{J} \left(P_j^{min} \times U_{jk} \right) \leq \mu U_{curt,ks} \ , \qquad \forall k, s \tag{3-28}$$

$$P_{Curt,ks} \leq \mu U_{curt,ks} \ , \qquad \forall k, s \tag{3-29}$$

The price of performing load shedding and power curtailment, C_{DSM}, in the objective function, shown in Equation (3-19), is assigned to a high value. This is to insure that renewable and dispatchable generators has higher priority to supply the load over performing load shedding and power curtailment when the conditions in Equations (3-22) and (3-23) are satisfied.

It is worth noting that formulating the problem as a multi-scenario stochastic model does not affect the number of the commitment integer variables U_{jk}. This is because the unit commitment problem is supposed to provide only one commitment schedule for the entire scheduling horizon. Nevertheless, continuous variables such as the power production level, P_{jks}, should increase based on the number of scenarios created. To cover a wider range of uncertainties, more states can be added to the discretized error distribution functions causing a larger number of scenarios, and thus creating more continuous variables in the unit commitment problem. However, increasing the number of scenarios will increase the computational burden of the problem.

Chapter 4
Simulations and Results

This chapter presents several study cases using the proposed models in Chapter 3. The models solve the day-ahead unit commitment problem of a microgrid operating in grid-connected mode and isolated mode. The problem has a time horizon of 24 hours with a 1 hour time step. Three main study cases are going to be discussed. The first one analyzes the operation of the microgrid during both modes of operation and under different demand profiles. The second study case examines the effects of uncertainties on the microgrid's expenses by considering variable levels of uncertainty. Finally, the last study case evaluates how changing the amount of spinning reserve requirement affects the total expenses of the microgrid.

4.1 System's parameters

A hypothetical microgrid that has eight dispatchable generation units, one wind turbine, and one PV system is considered. The system has a total capacity of 3.9MW with a renewable penetration level of 33%. The total installed capacity of the dispatchable units is 2.6MW. The parameters of the dispatchable units are shown in Table 4-1 [42]. Due to the lack of ramp rates data, the ramp rates of all the units are assumed to be equal to P^{max}. This assumption is justified because, considering their sizes, all the units should be able to reach their maximum generation limit within one hour which is the time step considered in this study [9]. The capacity of the wind turbine is equal to 1.1MW. The turbine parameters and the wind speed profile are adapted from [43]. The PV system has a capacity of 200kW, where the system parameters, the insolation profile, and the temperature profile are obtained from [42]. The capacity of the line linking the upstream grid and microgrid is assumed to be equal to 1000kW [3]. A demand profile from a typical weekday in October for a microgrid that contains industrial, commercial, and residential loads is used [9]. Two linearly modified versions of the demand profile are created to simulate the cases of excess demand and excess renewable generation that were discussed previously in Section 3.2. It should be noted that the wind and the solar power generation profiles remain the same in both cases, and only the demand profile is modified. The loads are categorized into critical and non-critical loads such that one third of the total load at any time period is assumed to be critical. The excess demand and the excess renewable generation profiles for a horizon of 24 hours are shown in Figure 4-1 and Figure 4-2, respectively.

Table 4-1: Dispatchable units' parameters

Unit #	P_{max} (kW)	P_{min} (kW)	a ($/Hr)	b ($/kWh)	c ($/kW^{2}h) $\times 10^{-4}$	MUT (Hr)	MDT (Hr)	HSC ($)	CSC ($)	CSC (Hr)	Initial status (Hr)
1	600	100	5	4	10	5	5	550	1100	3	-5
2	600	100	5	6	20	5	5	500	1000	3	-5
3	400	100	20	8	25	3	3	450	900	2	-3
4	300	50	30	10	20	2	2	800	1600	1	-2
5	300	100	30	12	20	2	2	750	1500	1	-2
6	200	100	40	14	15	2	2	720	1440	1	-2
7	100	50	55	15	12	1	1	560	1120	0	-1
8	100	50	55	17	12	1	1	570	1140	0	-1

The probability distribution functions of the load, wind power, and solar power forecasting errors are extracted from [27] and shown in Figure 4-3. The load and wind power probability distribution functions are discretized into 5 states and the solar power function into 3 states. Table 4-2 shows the discrete sets of the three probability distribution functions [27]. Using a two-stage scenario tree, 75 scenarios are generated. Few of the scenarios generated are shown in Table 4-3. A complete list of all the scenarios and their probabilities is provided in Table 5-1 in Appendix A. Figure 4-4 shows the expected net demand during the excess demand profile in a black solid line. The grey lines represent the 75 scenarios that create an uncertainty interval surrounding the expected value of the net demand. Net demand is the amount of demand left after subtracting the wind and solar power. It is, therefore, the demand that the dispatchable units and the upstream grid should supply. It has to be highlighted at this point that the inter-temporal changes are not considered in the 75 scenarios. Each scenario is assuming a certain level of deviation for the entire time domain.

The two formulations presented in Section 3.4 were modeled using the General Algebraic Modeling System (GAMS), and solved using CPLEX solver [35]. Each model needs 8 to 13 seconds to find the optimal solution. The computation time was recorded on a windows based PC with 2.1GHz processor and 2.0GB of RAM. The price of grid power is assumed to be 100$/kWh. The price of load shedding and power curtailment is assumed to be equal to 200$/kWh. Both prices were selected such that they are more expensive than the fuel cost of any of the dispatchable units. The price of the reserve is equal to 0.01$/kWh [3]. The spinning reserve requirement in the grid-connected mode is equal to 10% of the entire demand, while it is equal to 10% of only the critical demand in the isolated mode. The forecasting error factors were adapted from [3] as follows: the load forecasting error factor α_D equals to 0.03, the wind forecasting error factor α_W equals to 0.13, and the solar forecasting error factor α_{PV} equals to 0.09. The value of the constant μ used in Equations (3-24)-(3-29) equals to 5000.

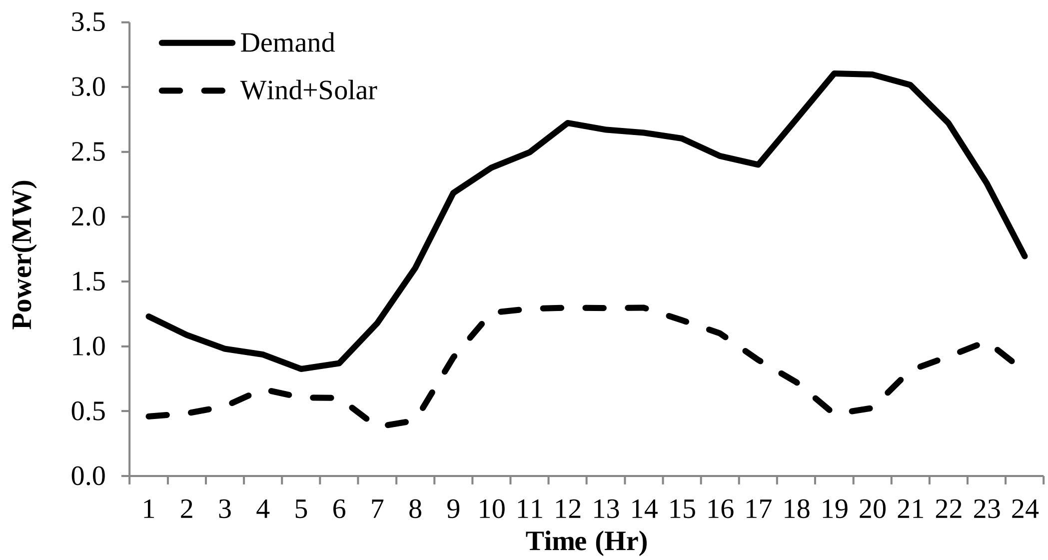

Figure 4-1: Excess demand profile

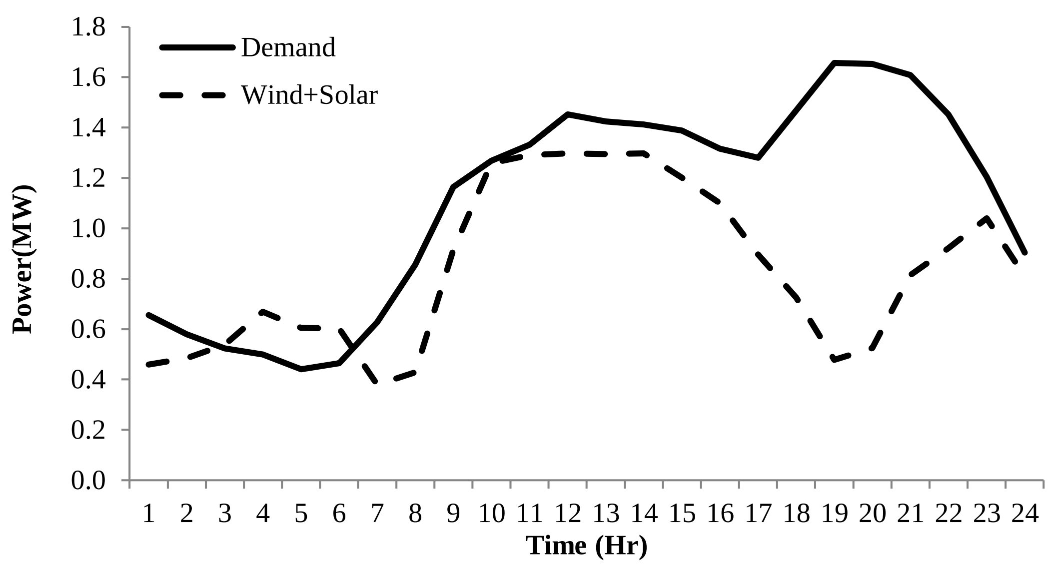

Figure 4-2: Excess renewable generation profile

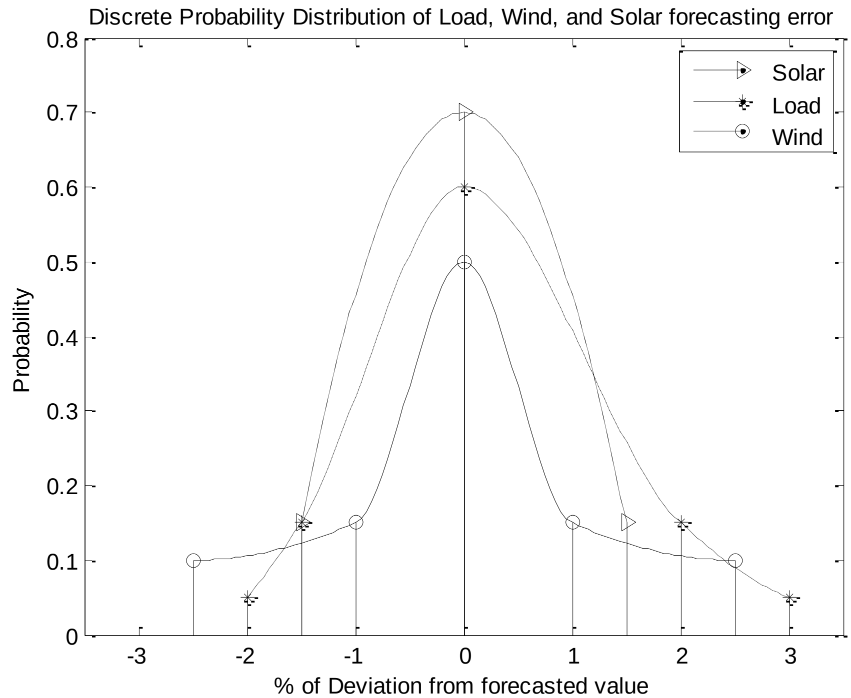

Figure 4-3: Discretized probability distribution functions of the load, wind power, and solar power forecasting errors

Table 4-2: The discrete sets of the PDFs representing the forecasting errors

Load		**Wind**		**Solar**	
% of deviation from forecast	Probability	% of deviation from forecast	Probability	% of deviation from forecast	Probability
-2.0	0.05	-2.5	0.10	-1.5	0.15
-1.5	0.15	-1.0	0.15	0.0	0.70
0.0	0.60	0.0	0.50	+1.5	0.15
+2.0	0.15	+1.0	0.15	-	-
+3.0	0.05	+2.5	0.10	-	-

Table 4-3: Part of the scenarios and their probabilities

Scn.	Deviation from forecasted load	Deviation from forecasted wind	Deviation from forecasted solar	Probability
1	-2.0%	-2.5%	-1.5%	0.00075
2	-2.0%	-2.5%	0.0%	0.00350
:	:	:	:	:
15	-2.0%	+2.5%	+1.5%	0.00075
:	:	:	:	:
61	+3.0%	-2.5%	-1.5%	0.00075
:	:	:	:	:
74	+3.0%	+2.5%	0.0%	0.00350
75	+3.0%	+2.5%	+1.5%	0.00075

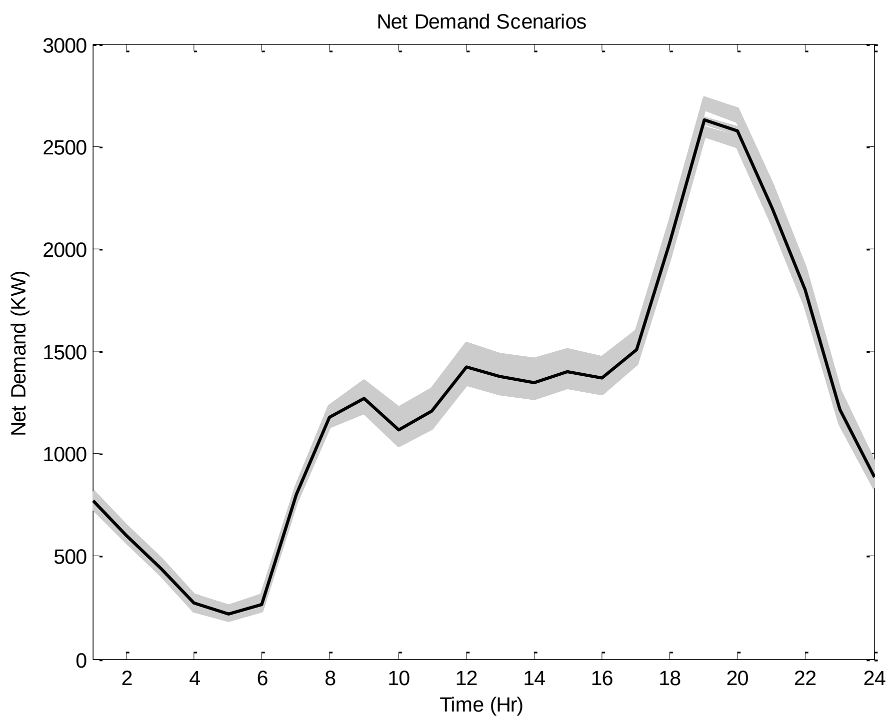

Figure 4-4: Net demand profile and the created scenarios

4.2 Study case 1: Microgrid's operation

To study the operation of a microgrid during grid-connected and isolated mode, the load and the renewable power generation profiles shown in Figure 4-1 and Figure 4-2 are applied. The two profiles are used to simulate the cases of excess demand and excess renewable generation during both modes of operation. Therefore, there will be four different cases to examine the operation of a microgrid. It is important to note that in each of the four cases under study, 75 scenarios of the load and the renewable power generation are applied. In each case, the day-ahead unit commitment model will provide one commitment schedule, and 75 power generation schedules. In other words, the same units will be committed for all the 75 scenarios; however, the power generated by the units varies from one scenario to the other due to the variations in the load and renewable power generation. In spite of that, the provided solution should meet all the units' and system's constraints during any scenario.

The day-ahead unit commitment models are supposed to accommodate all the renewable power, schedule the generation from the dispatchable units, control the power exchange with the upstream grid in the grid-connected mode, and perform load balancing measures in the isolated mode only if it is necessary to do so. The models should maintain the power balance in the system and meet the spinning reserve requirement at any time period during the day. Figure 4-5 shows the solution of the day-ahead unit commitment problem for the four cases under study. Each bar shows the amount of power supplied by the renewable generators and the dispatchable units to meet the microgrid's demand during a certain time period. In addition to that, the power exchanged with the upstream grid during the grid-connected mode and the load shedding and the power curtailment actions performed during the isolated mode are shown at the top of each bar. The total system's demand in each case is shown by the purple line. The numerical results of the four cases are shown in details in Appendix B. Figure 4-5a and Figure 4-5b are the results of scenario 61 which represents the worst case scenario during the excess demand profile such that the load has the highest positive deviation from its forecasted value, and the wind and solar power have the highest negative deviation. In other words, scenario 61 represents the highest net demand. Similarly, Figure 4-5c and Figure 4-5d are the results of scenario 15 which represents the worst case scenario during the excess renewable generation profile such that the load has the highest negative deviation from its forecasted value, and the wind and solar power have the highest positive deviation. In other words, scenario 15 represents the lowest net demand. The following is a discussion on the results of each of the four cases in reference to the discussion in Section 3.2, Figure 4-5, and the numerical results shown in Appendix B.

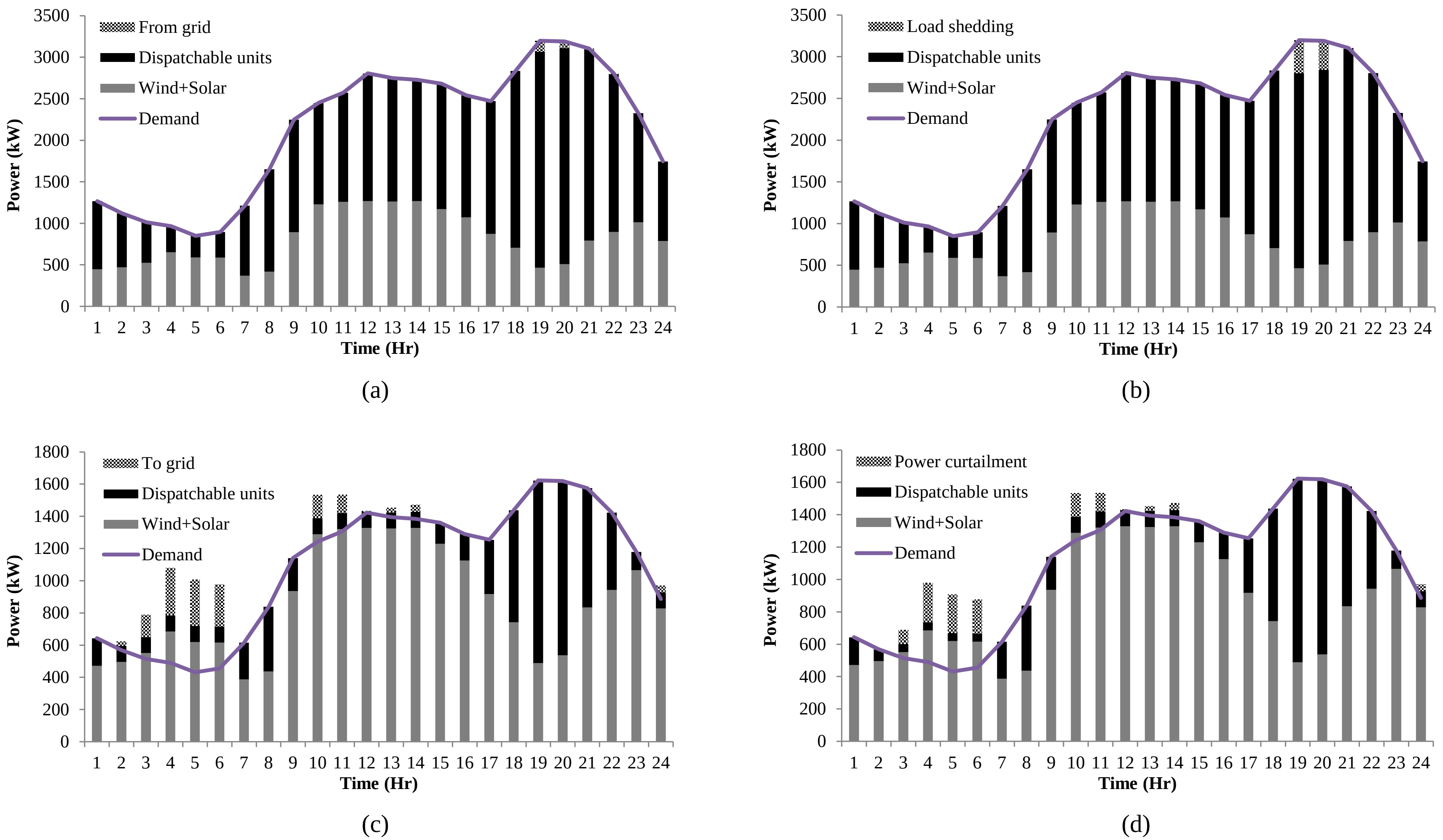

Figure 4-5: Microgrid operation: a) Grid-connected mode: Excess demand, b) Isolated mode: Excess demand, c) Grid-connected mode: Excess renewable generation, d) Isolated mode: Excess renewable generation

4.2.1 Grid-connected mode: Excess demand

Figure 4-5a and Table 5-3 present the microgrid operation during grid-connected mode under excess demand profile. It is noticed that the microgrid is having a normal operation during most of the time. All the renewable generation is first accommodated. Any remaining demand is supplied by the dispatchable units. However, during time periods 19-22, power is imported from the upstream grid. At time periods 19 and 20, the net demand exceeds the total capacity of all the dispatchable units which is 2.6MW; therefore, the excess demand is supplied by the upstream grid. At time periods 21 and 22, the net demand does not exceed the total capacity of all the dispatchable units. However, not all the units are committed. The committed units are operating at their maximum capacity which is less than the net demand in both time periods. Therefore, the amount of net demand that exceeds the capacity of the committed units is supplied by the upstream grid.

Someone might argue that since the net demand during time periods 21 and 22 does not exceed the total capacity of all the dispatchable units, then the entire demand should be supplied by the dispatchable units and no power has to be imported from the upstream grid, especially that the upstream grid has a higher cost compared to any of the dispatchable units. Although this argument is reasonable, few points should be highlighted to justify the solution. The unit commitment problem provides a commitment schedule that is shared by all the 75 scenarios. Therefore, other scenarios and their probability of occurrence are taken into consideration when making the commitment decisions. The solution presented in Figure 4-5a and Table 5-3 corresponds to scenario 61 which has the highest net demand compared to any other scenario. This means that during most of the remaining scenarios, the committed capacity is enough to supply the net demand during time periods 21 and 22, and no power is imported from the upstream grid. To further confirm this, the solution of scenario 15 that has the lowest net demand is shown in Table 5-4. It is clearly shown that during time periods 21 and 22, the entire demand is supplied by the dispatchable units and no power is imported from the upstream grid. Therefore, in spite of being uneconomical during scenario 61, the provided solution presents the most economical solution for all the 75 scenarios considered in the model.

The connection with the upstream grid provides the microgrid with an extra spinning reserve that exceeds the spinning reserve requirement at any time period. Therefore, it was possible to operate the committed units during time periods 19-22 at their maximum capacity. It can be also noticed that during these time periods the available spinning reserve is equal to the maximum capacity the upstream grid can provide minus the imported power.

4.2.2 Grid-connected mode: Excess renewable generation

Figure 4-5c and Table 5-5 present the microgrid operation during grid-connected mode under excess renewable generation profile. The microgrid is having a normal operation during most of the time periods except for periods 2-6, 10-14, and 24. During these periods, the microgrid is exporting power to the upstream grid. In time periods 3-6, and 10-11, the generated renewable power exceeds the total demand. Therefore, the net demand is negative. During these time periods, unit 1 is committed and operating at its minimum power limit which is 100kW. Therefore, the amount of power exported to the upstream grid during these time periods equals to the excess renewable generation in addition to the 100kW generated by unit 1. During time periods 2, 12-14, and 24, the total demand exceeds the renewable power generation in the system; therefore, unit 1 is committed. However, the amount of net demand that has to be supplied by unit 1 is less than its minimum power limit. As a result, excess power is generated by unit 1 and exported to the upstream grid.

One unanticipated finding is the commitment of a dispatchable unit during time periods when excess renewable generation occurs. Time periods 3-6, and 10-11 have enough renewable generation to supply the entire demand without the need to commit any dispatchable unit. Furthermore, the connection with the upstream grid can provide all the required spinning reserve; thus, none of the dispatchable units has to be connected to provide the spinning reserve. In spite of that, unit 1 was committed. This solution can be explained by the effect of other scenarios on the unit commitment solution. While these time periods are witnessing excess renewable generation during scenario 15, the same time periods during other scenarios are not necessarily witnessing the same thing. To verify this, the solution of scenario 61 under the same profile was inspected. Scenario 61 is the scenario that has the highest net demand during the excess renewable generation profile. The numerical solution of this scenario is shown in Table 5-6. It was found that during time periods 3, and 10-11, the microgrid is no longer witnessing excess renewable generation. This justifies why dispatchable unit 1 was committed during these time periods. However, time periods 4-6 are still witnessing excess renewable generation, and nevertheless unit 1 is still committed. This decision can be justified by analyzing and comparing the operating costs of the different possible alternatives. In reference to Table 4-1 and Equation (2-3), the cost of operating unit 1 at its minimum limit of 100kW for 3 hour, i.e. during time periods 4-6, is equal to 1215$. On the other hand, shutting unit 1 off starting at time period 4 requires turning on the same unit at a later time period which results in a starting up cost of 1100$. Furthermore, due to the minimum down time constraint, unit 1 has to remain off for 5 hours. As a result, another more expensive unit has to be committed during time periods 7 and 8 to meet the microgrid's demand. It is, therefore, justified to keep unit 1 one during time periods 4-6 even though there is enough renewable power generation to meet the demand. In summary, operating an already committed unit during periods of high renewable generation can be sometimes more economical than shutting all the units off. However, this conclusion cannot be generalized because it is affected by the type of the generators in use and their cost parameters. It is worth mentioning that, according to Table 4-1, unit 1 has the lowest operating cost compared to any other unit in the system. Therefore, it was the first unit to be committed during all the time periods.

It is arguable that during time periods 2, 12-14, and 24, in scenario 15, the excess generation from unit 1 can be avoided by committing units with lower minimum power limit such as unit 4, 7, and 8 that have a minimum generation limit of 50kW. The reason for committing unit 1 during these time periods is because of its low operating cost compared to the other units. Furthermore, unit 1 is the preferred and most economical solution during the other neighboring time periods. Therefore, committing other units will increase the operating cost and affect the other neighboring time periods due to the minimum up and down time constraints of unit 1. However, the most effective reason is having no expenses on exporting power to the upstream grid. Therefore, it is not considered when minimizing the objective function. The spinning reserve was not a concern in this case due to the availability of the upstream grid and the excess renewable power generation.

4.2.3 Isolated mode: Excess demand

Figure 4-5b and Table 5-7 present the microgrid operation during isolated mode under excess demand profile. The microgrid is having a normal operation during most of the time periods except for periods 19-21. Since the microgrid is isolated from the upstream grid, any excess demand has to be shed in order to maintain the system's power balance. Furthermore, an additional shedding is performed to provide the required spinning reserve for the critical loads. This is because the only source available to provide the spinning reserve in the isolated mode is the local dispatchable units. During time periods 19 and 20, the net demand exceeds the total capacity of all the dispatchable units. Therefore, an amount of power equal to the excess demand plus the spinning reserve requirement is shed. At time period 21, the microgrid is not witnessing any excess demand and the total committed capacity is capable of supplying the net demand. However, the maximum power that the dispatchable units can supply at this time period is equal to their full capacity minus the reserve requirement. The remaining capacity is less than the system's net demand, and therefore power shedding is performed to maintain the power balance.

In contrast to the operation of the microgrid under the same profile but during grid-connected mode, the amount of power generated by the dispatchable units during time periods 19-20 in the isolated mode is lower than in the grid-connected mode. This is because the dispatchable units have to supply the spinning reserve, and thus their output power is reduced. The available spinning reserve in the system during all the time periods in the isolated mode is lower than in the grid-connected mode. This is due to the disconnection from the upstream grid that was supplying a large portion of the spinning reserve. It is noticed that during time periods 19-21 in the isolated mode, the amount of spinning reserve available equals to the required spinning reserve as shown in Table 5-7. During these time periods, the required spinning reserve is provided through load shedding. However, since the cost of load shedding is included in the objective function, load shedding is minimized, and therefore only the required spinning reserve is allocated.

4.2.4 Isolated mode: Excess renewable generation

Figure 4-5d and Table 5-8 present the microgrid operation during isolated mode under excess renewable generation profile. The microgrid is having a normal operation during most of the time periods except for periods 3-6, 10-14, and 24. During these time periods, the microgrid is generating more power than its demand; therefore, the excess generation has to be curtailed in order to maintain the system's power balance. Similar to grid-connected mode, the excess generation is either due to the excess renewable power generation, or due to a net demand that is less than the minimum power limit of the committed dispatchable unit.

During time periods 3-6, and 10-11, the microgrid is having an excess renewable generation; therefore, the excess generation has to be curtailed. However, in order to provide the required spinning reserve for the critical loads, at least one dispatchable unit has to be committed which increase the total power generation in the system. As a result, an additional power curtailment is performed. During time periods 12-14, and 24, there is no excess renewable generation; however, the net demand is lower than the minimum generation limit of the committed unit which is unit 1 in this case. As a result, the extra power generated by unit 1 has to be curtailed.

It is noticed that during the time periods of excess renewable generation, unit 4, that has a minimum power limit of 50kW, was committed during time periods 3-6, while unit 1, that has a minimum power limit of 100kW, was committed during time periods 10, and 11. A justified question would be why unit 1 was not committed during all the time periods as was the case in the grid-connected mode in Section 4.2.2. There are two reasons to explain this solution. The first is related to the amount of spinning reserve required. Unit 4 was sufficient to supply the spinning reserve requirement during time periods 3-6. However, at time periods 10, and 11, the spinning reserve requirement exceeds the capacity of unit 4. Therefore, a larger unit should be committed. Unit 1 is the best alternative because it has the lowest operating cost and the largest capacity. The second reason is due to the high cost of power curtailment. During time periods 3-6, it is possible to use unit 1 instead of unit 4. However, a larger power curtailment would be required in that case because unit 1 has a higher minimum power limit compared to unit 4.Therefore, choosing unit 4 over unit 1 is more economical. Units 7 and 8 also have a minimum generation limit of 50kW; however, the remaining capacity is not enough to supply the required spinning reserve. Therefore, unit 4 was selected.

4.3 Study case 2: Effects of uncertainties

To study the effects of uncertainties on the day-ahead unit commitment problem in microgrids, four different cases are examined in each mode of operation. The excess demand profile shown in Figure 4-1 is applied to all the cases under study. The following is a description of the four cases:

- <u>Case 1 - No renewables:</u> This case assumes that there are no uncertainties in the system. It replaces the renewable generators that have a total capacity of 1.3MW with three dispatchable units of capacities 600kW, 400kW, and 300kW. These new units are duplicates of units 2, 3, and 5 that were shown earlier in Table 4-1. Only one load forecast scenario is examined.

- <u>Case 2 - With renewables + no uncertainties:</u> This case uses the same system that was presented earlier in this chapter with 8 dispatchable units, one wind turbine, and one PV system. Only one forecast scenario is considered for the load, solar power, and wind power.

- <u>Case 3 - With renewables + uncertainties:</u> This case is similar to case 2; however, uncertainties are considered. Uncertainties are represented using the 75 scenarios that were presented earlier.

- <u>Case 4 - With renewables + higher uncertainties:</u> This case is similar to case 3; however, higher uncertainties are assumed. The higher uncertainties are obtained by assigning a larger standard deviation to the probability distribution functions of the load, wind power, and solar power forecasting errors. The discrete sets of the new probability distribution functions are extracted from [27] and shown in Table 4-4. A new set of scenarios is generated with a total of 75 scenarios. A complete list of all the scenarios generated and their probabilities is provided in Table 5-2 in Appendix A.

Table 4-4: The discrete sets of forecasting errors with higher uncertainties

Load		Wind		Solar	
% of deviation from forecast	Probability	% of deviation from forecast	Probability	% of deviation from forecast	Probability
-3.0	0.05	-5.0	0.10	-2.5	0.15
-2.0	0.15	-2.0	0.15	0.0	0.70
0.0	0.60	0.0	0.50	+2.5	0.15
+3.0	0.15	+2.0	0.15	-	-
+4.0	0.05	+5.5	0.10	-	-

Since this study case is examining the effects of uncertainties on the unit commitment problem, the amount of spinning reserve required is kept constant at 10% of the demand during all the cases. No additional reserve is allocated. This is done to limit the variations between the cases and to be able to isolate the effects of changing the spinning reserve requirement. Section 4.4 presents a detailed study case about the effects of varying the spinning reserve requirement on the microgrid's expenses.

To compare the cases with each other, the total expected expenses of the microgrid are calculated in each case. The total expenses represent the objective function that the day-ahead unit commitment models are trying to minimize as discussed earlier in Section 3.4. The total expenses are equal to the addition of the dispatchable units' operating cost, the available spinning reserve cost, the cost of importing power from the upstream grid in grid-connected mode, and the cost of load shedding in isolated mode. Since only excess demand profile is applied in this study case, no power curtailment actions are performed. The expenses of operating the microgrid during grid-connected mode and isolated mode for the four cases under study are given in Table 4-5 and Table 4-6, respectively.

Table 4-5: Expenses of operating a microgrid in grid-connected mode

Case	Microgrid Expenses ($)	Dispatchable units' operating cost ($)	Power import cost ($)	Spinning reserve cost ($)
1	310782	310451	0	331
2	193866	190743	2800	324
3	196237	191466	4442	328
4	197821	191627	5865	329

Table 4-6: Expenses of operating a microgrid in isolated mode

Case	Microgrid Expenses ($)	Dispatchable units' operating cost ($)	Load shedding cost ($)	Spinning reserve cost ($)
1	312098	312001	0	97
2	229998	188363	41543	92
3	233592	190297	43181	114
4	235342	190590	44638	114

Comparing case 1 between the two modes, it is noticed that the expenses of the microgrid during the isolated mode are higher than the expenses during the grid-connected mode. Although the dispatchable units in both cases are supplying the exact same amount of power, more units are committed in the case of the isolated mode in order to provide the required spinning reserve. Therefore, the operating cost of the dispatchable units is higher, and thus the total expenses are higher. On the other hand, the reserve cost in the grid-connected mode is higher than in the isolated mode because a larger amount of reserve is available to the microgrid during the grid-connected mode due to the connection with the upstream grid. The two cases are not importing any power from the upstream grid, nor shedding any load. This is because all the units in case 1 are dispatchable; thus, they are capable of supplying the entire load at any moment during the day.

Comparing case 1 to cases 2-4 in both modes of operation, the total expenses in case 1 are higher because no renewable generators are present. Renewable generators provide power at no cost, and thus they reduce the power supplied by the dispatchable units. This is clearly shown by comparing the dispatchable units' operating cost between case 1 and cases 2-4 in both modes of operation. At the same time, the spinning reserve cost in case 1 is also higher than the spinning reserve cost in most of the other cases. This is because more dispatchable units are committed in case 1. The remaining capacities of these units contribute to the spinning reserve.

Comparing cases 2-4 in both modes of operation, it is noticed that the costs of importing power form the grid in the grid-connected mode, is lower than the costs of load shedding in the isolated mode. This is due to two reasons. First, the power imported in the grid-connected mode is equal only to the excess demand. However, in the isolated mode, load shedding is performed to shed the excess demand and to allocate the spinning reserve requirement. Secondly, the cost of shedding 1kW of load is higher than the cost of importing 1kW of power from the upstream grid as mentioned in Section 4.1. On the other hand, the dispatchable units' operating cost in cases 2-4 in the isolated mode is lower than in the grid-connected mode. The explanation of this difference is that the dispatchable units in the isolated mode should provide the spinning reserve to the microgrid; therefore, their output power is reduced resulting in a lower operating cost.

Increasing the uncertainties in cases 2-4 during both modes of operation caused an increase in all the costs in the system. This is because the presence of higher uncertainties requires committing more dispatchable units to mitigate their effects. This can be considered as a precaution action that is taken to avoid any service outage. The benefits of such decision are not known until all the uncertainties are realized, i.e. at the dispatch time. Although committing more units increases the expenses of the microgrid, this action can prevent the microgrid from taking more expensive measures to balance the power at the dispatch time.

The spinning reserve cost in the grid-connected mode is larger than in the isolated mode during all the cases due to the presence of the upstream grid that is increasing the available spinning reserve in the system. A slight increase in the cost of spinning reserve is noticed in cases 2-4 during both modes of operation. This is due to the increase in load forecasting uncertainties. The required spinning reserve in all the cases is a percentage of the system's demand. Therefore, increasing the uncertainties of the demand increases the spinning reserve requirement.

As expected earlier in Section 3.2, operating the microgrid in grid-connected mode, for any of the four cases, is less expensive than operating it in the isolated mode. This can be explained by the lack of power and spinning reserve resources during the isolated mode. It is important to highlight that the costs presented in Table 4-5 and Table 4-6 are the expected costs and not the actual operating costs. Due to the uncertainties presented in the problem, the system might require more or less power at the dispatch time. Therefore, the actual expenses might differ from what is expected by the day-ahead unit commitment problem.

4.4 Study case 3: Effects of spinning reserve

This study case evaluates the effects of varying the spinning reserve requirement on the expenses of the microgrid during both modes of operation and under different demand profiles. The excess demand and the excess renewable generation profiles are applied to each mode of operation forming four different cases. In each case, the unit commitment problem is solved 31 times using a different amount of spinning reserve. The spinning reserve requirement is increased as a percentage of the total demand from 0% to 30% in steps of 1%. To study a wider range of reserve variations, the spinning reserve in the isolated mode is estimated based on the total demand and not only the critical demand. Uncertainties are considered in all the cases using the 75 scenarios shown in Table 5-1 in Appendix A. To compare the cases with each other, the total expenses of the microgrid are calculated in each case. The total expenses are equal to the addition of the dispatchable units' operating cost, the available spinning reserve cost, the cost of importing power from the upstream grid in the grid-connected mode, and the cost of load shedding and power curtailment in the isolated mode.

Figure 4-6 shows the total expenses when varying the spinning reserve requirement in a microgrid operating in grid-connected mode under excess demand profile. All the costs have remained the same for the entire range of spinning reserve requirement, except for 28% to 30% of the demand. When inspecting these results, it was found that the amount of spinning reserve available in the system, when the spinning reserve requirement was equal to 0% of the demand, was larger than the spinning reserve requirement at 27% of the demand. In other words, the commitment solution for a reserve requirement of 0% is feasible and optimal for the case of 27%. Therefore, the same solution was applied in all the cases. At a spinning reserve requirement of 28% of the demand, the total capacity of the dispatchable units in addition to the capacity of the line linking the upstream grid and the microgrid were no longer able to meet the power and the reserve requirements of the system. Therefore, load shedding had to be performed to free a portion of the capacity in order to provide the required spinning reserve. This requires reducing either the power imported from the upstream grid, or the power generated by the local dispatchable generators in order to maintain the power balance in the system. Since the power is imported from the upstream grid at a higher cost compared to the operating cost of any of the local dispatchable generators, the power import was reduced. It should be noted that the formulation presented in Section 3.4.1 for a day-ahead unit commitment problem during grid-connected mode resulted in an infeasible solution for reserve requirements above 27% of the demand. This is because the capacity of all the dispatchable generators along with the upstream grid was not enough to meet the demand and provide the required spinning reserve at the same time. The infeasibility was escaped by performing load shedding. Load shedding was incorporated in the problem formulation of the grid-connected mode in a similar manner to what was presented in the isolated mode formulation in Section 3.4.2.

Figure 4-7 shows the expenses in the same system during the excess renewable generation profile. Due to the availability of the spinning reserve, the same solution was feasible and optimal for the entire range of spinning reserve requirements.

It is important to highlight that a spinning reserve requirement of 0% does not indicate that no spinning reserve is available in the system. It simply means that the spinning reserve constraints are no longer active and that there is no minimum amount to be provided. Nevertheless, spinning reserve is still available in the system due to the commitment of the dispatchable units and the connection with the upstream grid. Although a very large amount of spinning reserve is available when no reserve is required, the obtained solution represents the most economical alternative. This is because the cost of spinning reserve provision is negligible if compared with the dispatchable units' operating cost, which is clearly shown in Figure 4-6 and Figure 4-7. The commitment solution at 0% reserve requirement was found to be optimal during the remaining range of reserve requirements. Therefore, it can be concluded that in grid-connected mode, the amount of spinning reserve requirement has a minimum or no effect on the operation and the expenses of the microgrid.

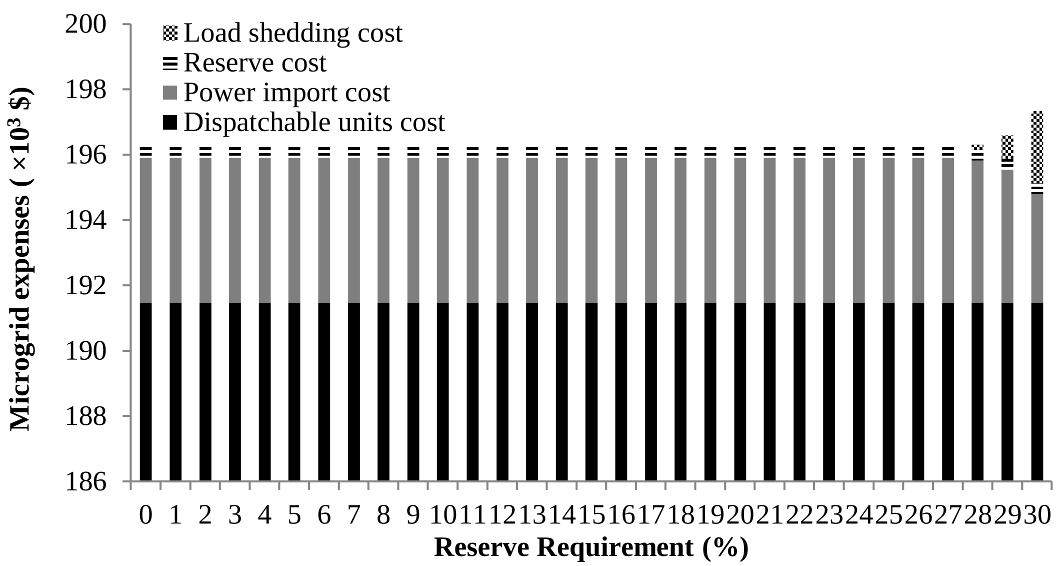

Figure 4-6: Variable reserve: Grid-connected mode – Excess demand profile

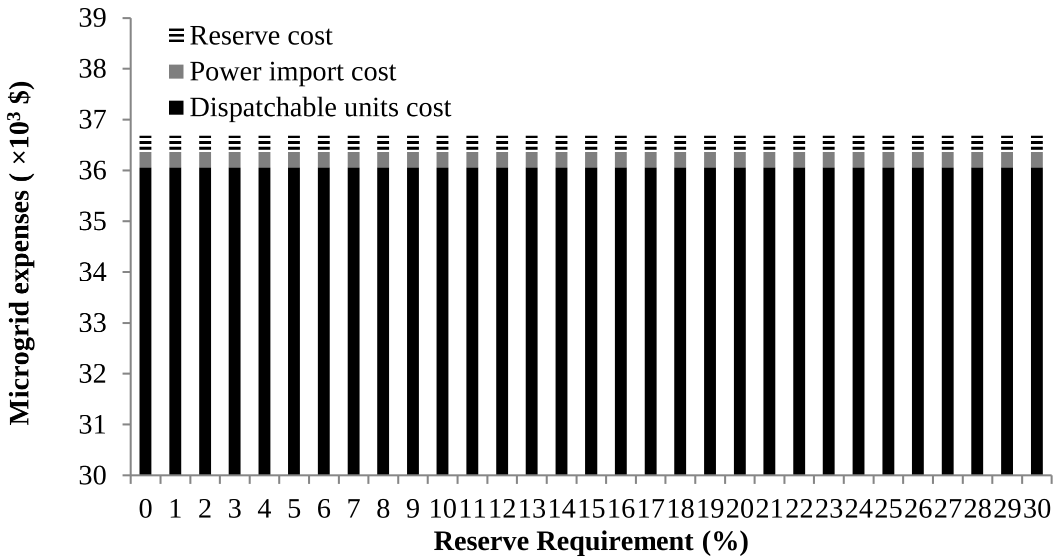

Figure 4-7: Variable reserve: Grid-connected mode – Excess renewable generation profile

Figure 4-8 shows the effects of varying the spinning reserve requirement in a microgrid operating in the isolated mode under excess demand profile. In contrast to the grid-connected mode, varying the reserve requirement has a significant effect on the expenses of the microgrid. This is due to the lack of spinning reserve resources. In the isolated mode, spinning reserve can be provided only by the dispatchable units. If any additional reserve is required, load shedding is performed to free a portion of the dispatchable units' capacity. This is shown in Figure 4-8b and Figure 4-8c. As the spinning reserve requirement increases from 0% to 30% of the demand, the cost of load shedding increases and the dispatchable units' operating cost decreases due to supplying less power. The reason behind that rapid increase in the load shedding cost is due to the high price assigned to load shedding actions. The provision of additional spinning reserve increases the reserve cost as well. This is clearly shown in Figure 4-8d.

Figure 4-9 shows the effects of varying the spinning reserve requirement in a microgrid operating in the isolated mode under excess renewable generation profile. In this case, renewable generators are capable of supplying the entire demand during few time periods. Any excess power is curtailed. Moreover, at least one unit has to be committed in order to supply the spinning reserve requirement. As a result, an additional amount of power is curtailed. Increasing the spinning reserve requirement involves committing more and larger units; therefore, power curtailment increases as shown in

Figure 4-9b. Similarly, increasing the spinning reserve requirement increases the cost of spinning reserve as shown in Figure 4-9d. Dispatchable units are also having an increasing operating cost with the increase of reserve requirement as shown in Figure 4-9c. This is due to committing more units in order to supply the required reserve. As discussed earlier, committing a unit means that it must generate a minimum amount of power. Therefore, committing more units means more power is being supplied resulting in higher operating cost. The dip in the dispatchable units' operating cost at a reserve requirement of 17% is due to the commitment of larger and less expensive dispatchable units. For reserve requirements less than 17%, small dispatchable units such as units 4 to 8 were used to supply the spinning reserve. However, these units have a high operating cost. At a reserve requirement of 17%, the small units are no longer enough to supply the reserve; therefore, larger units that are less expensive, such as unit 1, are committed instead. As the spinning reserve increases after 17%, the small expensive units are committed again because higher reserve is required. This explains the increase in the dispatchable units' operating cost as the spinning reserve requirement increases.

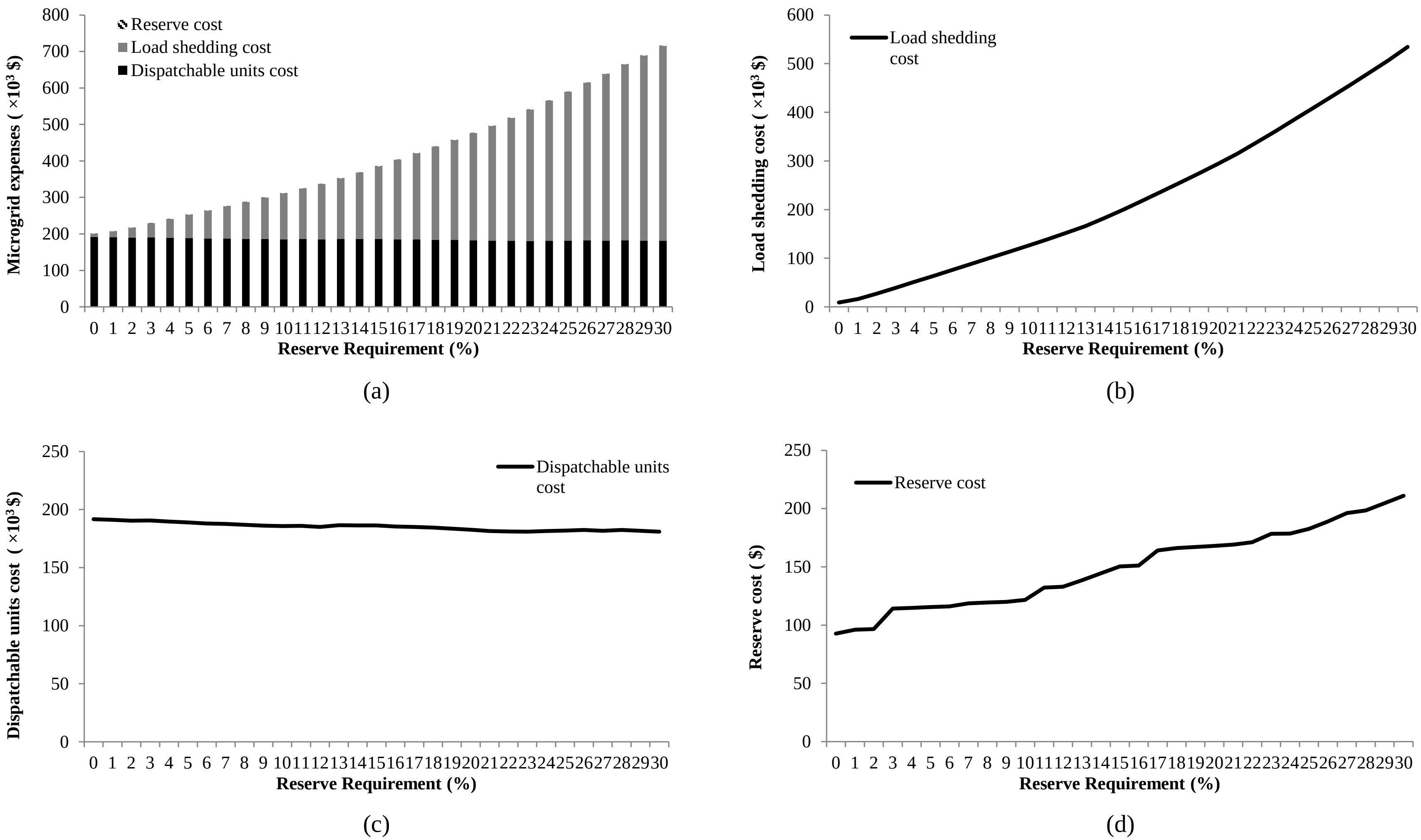

Figure 4-8: Variable reserve: Isolated mode – Excess demand profile: a) Total Expenses, b) Load shedding cost, c) Dispatchable units' operating cost, d) Reserve cost

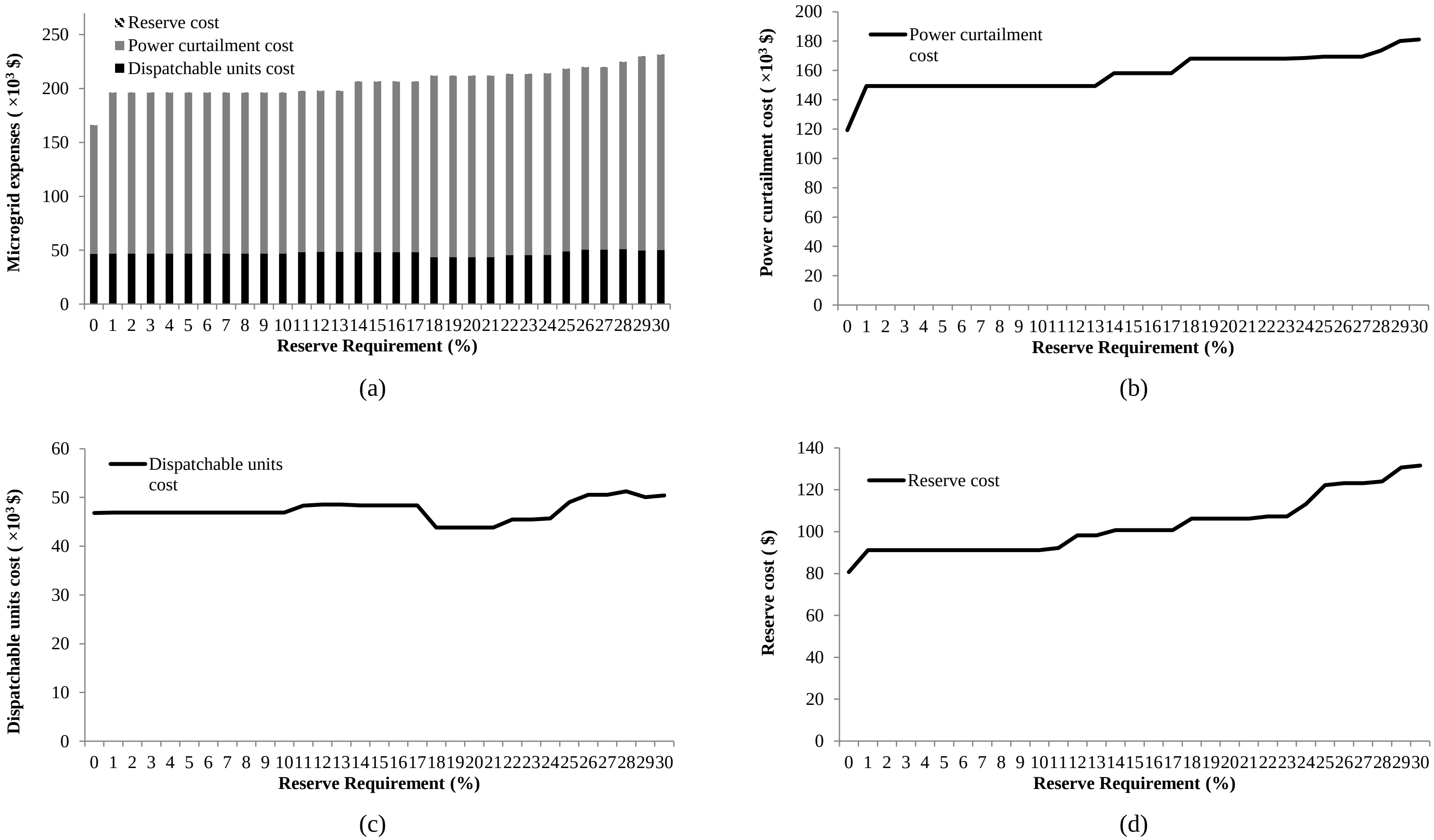

Figure 4-9: Variable reserve: Isolated mode – Excess renewable generation profile: a) Total Expenses, b) Power curtailment cost, c) Dispatchable units' operating cost, d) Reserve cost

The cost of providing spinning reserve in the isolated mode does not only include the cost of the unused capacity from the dispatchable units. It also includes the cost of load shedding and power curtailment actions that are required to provide the spinning reserve. In contrast to the grid-connected mode, only the required spinning reserve is provided in the isolated mode, and no additional reserve is allocated. This is a very important conclusion that should be taken into consideration when allocating an additional reserve requirement to mitigate the uncertainties. Providing an additional reserve in the isolated mode can cater the variations in the load and renewable power forecast; however, it can also increase the total expenses of the system due to the load shedding and power curtailment actions. Therefore a cost/benefit analysis is suggested in the isolated mode to select the optimal spinning reserve requirement that balances the benefits of supplying the spinning reserve with its costs.

Figure 4-10 shows a comparison between the total expenses of the four cases examined in this study case. The results are shown for a reserve requirement that is equal to 10% of the system's demand. Reserve and power imported from the upstream grid have a very small cost compared to the dispatchable units' operating cost and the load shedding and the power curtailment cost. Therefore, their values are shown as a thin layer at the top of each of the four bars in Figure 4-10.

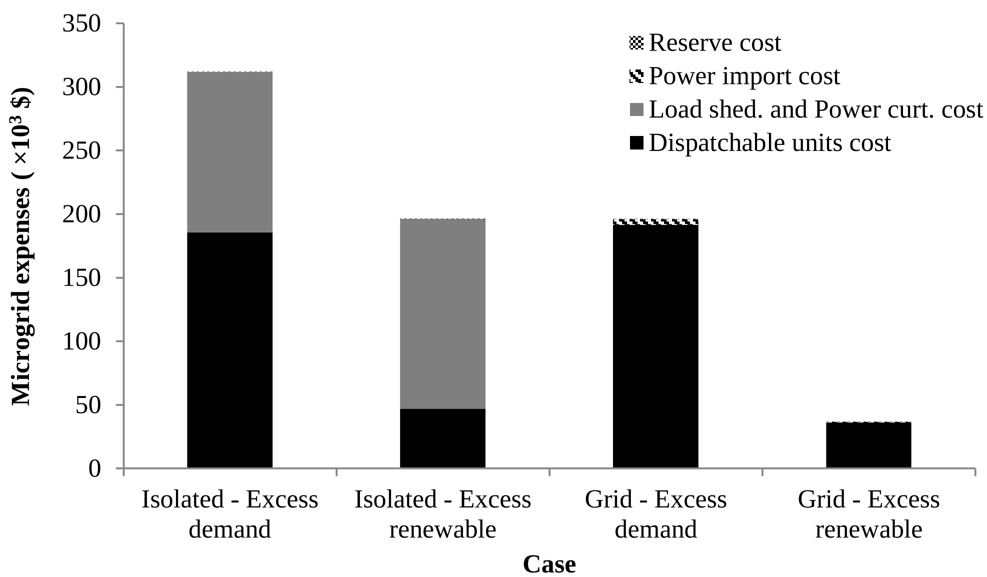

Figure 4-10: Total expenses at 10% spinning reserve requirement

It is noticed that the expenses during the isolated mode are higher than in the grid-connected mode due to the costs of load shedding and power curtailment actions. The cost of importing power from the upstream grid in the grid-connected mode is small because its price is lower than the price of load shedding and power curtailment actions. More importantly, the load shedding and power curtailment actions are not only performed due to excess demand or excess renewable generation, but also to supply the required spinning reserve. For excess demand profile, the dispatchable units' operating cost in the grid-connected mode is higher than in the isolated mode. This is because the dispatchable units in isolated mode have to supply the spinning reserve; therefore, they cannot operate at their maximum capacity like the case of grid-connected mode. For excess renewable generation profile, the dispatchable units' operating cost in the isolated mode is higher than in the grid-connected mode. This is because the dispatchable units in the isolated mode have to supply the spinning reserve; therefore, more units have to be committed resulting in a larger power generation, and thus a higher operating cost.

Chapter 5
Conclusion and Future Work

This thesis presented two optimization models to solve the day-ahead unit commitment problem in a microgrid operating in grid-connected and isolated mode. Uncertainties due to load and renewable power forecasting errors were handled in this research by allocating additional amounts of spinning reserve, and by reformulating the unit commitment problem as a multi-scenario stochastic model. Applying both techniques together can incorporate a wider spectrum of uncertainties in the problem, and therefore results in more robust and reliable commitment schedules. Using the proposed models, few study cases were examined to study the microgrid operation, and to evaluate the effects of uncertainties and spinning reserve on the total expenses.

In comparison to previous research work on the same topic, this thesis has made the following contributions:

- The two main and most applied uncertainty handling techniques were incorporated in the models, while previous work ignored the uncertainties or applied only one of the two methods.
- The proposed models were solved using mathematical optimization methods that guarantee an optimal solution instead of the suboptimal solution that was provided by meta-heuristic optimization methods used in some of the previous studies.
- The microgrid was investigated during both modes of operation, especially during the isolated mode which was not examined in most of the former studies.
- A detailed evaluation of the spinning reserve provision in microgrids during both modes of operation was presented. Such evaluation was not reported in previous publications.

The operation of the microgrid during both modes of operation and under variable demand profiles was investigated in the first study case. It was found that due to the lack of spinning reserve resources in the isolated mode, large amounts of power are either shed or curtailed to provide the required spinning reserve. On the other hand, the upstream grid provides a large portion of the required spinning reserve in the grid-connected mode causing the microgrid to supply most of its demand from the local dispatchable generators. Therefore, dispatchable units' operating cost is higher in the grid-connected mode when compared to the isolated mode. The second study case evaluated the effects of increasing the uncertainties on the total expenses of the microgrid during both modes of operation. It was concluded that higher uncertainties requires committing more dispatchable units in order to mitigate their effects. As a result, the total expenses of the microgrid increases. The last study case examined the effects of varying the spinning reserve requirement on the microgrid's expenses. Minimal effect was reported during grid-connected mode because the upstream grid was providing enough reserve to cover a wide range of reserve requirement variations. However, increasing the reserve requirement in the isolated mode required performing more load shedding and power curtailment actions resulting in higher expenses. This is mainly due to the lack of spinning reserve resources during the isolated mode.

An important conclusion regarding the spinning reserve requirement in the isolated mode was drawn. Increasing the reserve helps in catering possible deviations in the forecasted load and renewable power generation. However, it also increases the total expenses of the microgrid due to performing expensive load shedding and power curtailment actions. Therefore, a cost/benefit analysis has to be performed to specify the optimal spinning reserve that can mitigate the uncertainties without a significant increase in the microgrid's expenses. Such analysis is recommended for future work.

For future enhancements on the proposed unit commitment models, a multi-stage scenario tree with scenario reduction methods can be used to create larger number of scenarios. This can provide a better representation of the system's uncertainties than a two-stage scenario tree that is adapted in this research. Furthermore, additional uncertainties such as the possible disconnection from the upstream grid and the outage of dispatchable units can be integrated in the model. The model can also be expanded to adapt other objectives such the minimization of gas emissions, or different load types such as shiftable loads.

A future work on this research includes examining the microgrid operation during the dispatch time when the uncertainties are realized. This would provide a better judgment on the benefits of the uncertainty handling techniques that are applied in the day-ahead unit commitment problem. It also provides the ability to study the operation of the microgrid when a sudden disconnection from the upstream grid occurs. Another interesting concept to be investigated in future work is the integration of energy storage systems in the microgrid. Energy storage systems can add a substantial benefit to the microgrid, especially during the isolated mode. They can participate in providing the required spinning reserve, and therefore reducing the need for load shedding and power curtailment actions. As a result, lower microgrid's expenses are expected. Another area that can be explored is how to coordinate multiple microgrids within one distribution system. This includes the power exchange and the provision of spinning reserve from one microgrid to the other.

Appendix A

Forecasting Errors Scenarios

Table 5-1: The generated 75 scenarios and their probabilities

Scn.	Load (%)	Wind (%)	Solar (%)	Prob	Scn.	Load (%)	Wind (%)	Solar (%)	Prob
1	-2.0	-2.5	-1.5	0.00075	39	0.0	0.0	+1.5	0.04500
2	-2.0	-2.5	0.0	0.00350	40	0.0	1.0	-1.5	0.01350
3	-2.0	-2.5	+1.5	0.00075	41	0.0	1.0	0.0	0.06300
4	-2.0	-1.0	-1.5	0.00113	42	0.0	1.0	+1.5	0.01350
5	-2.0	-1.0	0.0	0.00525	43	0.0	+2.5	-1.5	0.00900
6	-2.0	-1.0	+1.5	0.00113	44	0.0	+2.5	0.0	0.04200
7	-2.0	0.0	-1.5	0.00375	45	0.0	+2.5	+1.5	0.00900
8	-2.0	0.0	0.0	0.01750	46	+2.0	-2.5	-1.5	0.00225
9	-2.0	0.0	+1.5	0.00375	47	+2.0	-2.5	0.0	0.01050
10	-2.0	+1.0	-1.5	0.00113	48	+2.0	-2.5	+1.5	0.00225
11	-2.0	+1.0	0.0	0.00525	49	+2.0	-1.0	-1.5	0.00338
12	-2.0	+1.0	+1.5	0.00113	50	+2.0	-1.0	0.0	0.01575
13	-2.0	+2.5	-1.5	0.00075	51	+2.0	-1.0	+1.5	0.00338
14	-2.0	+2.5	0.0	0.00350	52	+2.0	0.0	-1.5	0.01125
15	-2.0	+2.5	+1.5	0.00075	53	+2.0	0.0	0.0	0.05250
16	-1.5	-2.5	-1.5	0.00225	54	+2.0	0.0	+1.5	0.01125
17	-1.5	-2.5	0.0	0.01050	55	+2.0	1.0	-1.5	0.00338
18	-1.5	-2.5	+1.5	0.00225	56	+2.0	1.0	0.0	0.01575
19	-1.5	-1.0	-1.5	0.00338	57	+2.0	1.0	+1.5	0.00338
20	-1.5	-1.0	0.0	0.01575	58	+2.0	+2.5	-1.5	0.00225
21	-1.5	-1.0	+1.5	0.00338	59	+2.0	+2.5	0.0	0.01050
22	-1.5	0.0	-1.5	0.01125	60	+2.0	+2.5	+1.5	0.00225
23	-1.5	0.0	0.0	0.05250	61	+3.0	-2.5	-1.5	0.00075
24	-1.5	0.0	+1.5	0.01125	62	+3.0	-2.5	0.0	0.00350
25	-1.5	1.0	-1.5	0.00338	63	+3.0	-2.5	+1.5	0.00075
26	-1.5	1.0	0.0	0.01575	64	+3.0	-1.0	-1.5	0.00113
27	-1.5	1.0	+1.5	0.00338	65	+3.0	-1.0	0.0	0.00525
28	-1.5	+2.5	-1.5	0.00225	66	+3.0	-1.0	+1.5	0.00113
29	-1.5	+2.5	0.0	0.01050	67	+3.0	0.0	-1.5	0.00375
30	-1.5	+2.5	+1.5	0.00225	68	+3.0	0.0	0.0	0.01750
31	0.0	-2.5	-1.5	0.00900	69	+3.0	0.0	+1.5	0.00375
32	0.0	-2.5	0.0	0.04200	70	+3.0	1.0	-1.5	0.00113
33	0.0	-2.5	+1.5	0.00900	71	+3.0	1.0	0.0	0.00525
34	0.0	-1.0	-1.5	0.01350	72	+3.0	1.0	+1.5	0.00113
35	0.0	-1.0	0.0	0.06300	73	+3.0	+2.5	-1.5	0.00075
36	0.0	-1.0	+1.5	0.01350	74	+3.0	+2.5	0.0	0.00350
37	0.0	0.0	-1.5	0.04500	75	+3.0	+2.5	+1.5	0.00075
38	0.0	0.0	0.0	0.21000	-	-	-	-	-

Table 5-2: The generated 75 scenarios with higher uncertainties and their probabilities

Scn.	Load (%)	Wind (%)	Solar (%)	Prob	Scn.	Load (%)	Wind (%)	Solar (%)	Prob
1	-3.0	-5.0	-2.5	0.00075	39	0.0	0.0	+2.5	0.04500
2	-3.0	-5.0	0.0	0.00350	40	0.0	+2.0	-2.5	0.01350
3	-3.0	-5.0	+2.5	0.00075	41	0.0	+2.0	0.0	0.06300
4	-3.0	-2.0	-2.5	0.00113	42	0.0	+2.0	+2.5	0.01350
5	-3.0	-2.0	0.0	0.00525	43	0.0	+5.0	-2.5	0.00900
6	-3.0	-2.0	+2.5	0.00113	44	0.0	+5.0	0.0	0.04200
7	-3.0	0.0	-2.5	0.00375	45	0.0	+5.0	+2.5	0.00900
8	-3.0	0.0	0.0	0.01750	46	+3.0	-5.0	-2.5	0.00225
9	-3.0	0.0	+2.5	0.00375	47	+3.0	-5.0	0.0	0.01050
10	-3.0	+2.0	-2.5	0.00113	48	+3.0	-5.0	+2.5	0.00225
11	-3.0	+2.0	0.0	0.00525	49	+3.0	-2.0	-2.5	0.00338
12	-3.0	+2.0	+2.5	0.00113	50	+3.0	-2.0	0.0	0.01575
13	-3.0	+5.0	-2.5	0.00075	51	+3.0	-2.0	+2.5	0.00338
14	-3.0	+5.0	0.0	0.00350	52	+3.0	0.0	-2.5	0.01125
15	-3.0	+5.0	+2.5	0.00075	53	+3.0	0.0	0.0	0.05250
16	-2.0	-5.0	-2.5	0.00225	54	+3.0	0.0	+2.5	0.01125
17	-2.0	-5.0	0.0	0.01050	55	+3.0	+2.0	-2.5	0.00338
18	-2.0	-5.0	+2.5	0.00225	56	+3.0	+2.0	0.0	0.01575
19	-2.0	-2.0	-2.5	0.00338	57	+3.0	+2.0	+2.5	0.00338
20	-2.0	-2.0	0.0	0.01575	58	+3.0	+5.0	-2.5	0.00225
21	-2.0	-2.0	+2.5	0.00338	59	+3.0	+5.0	0.0	0.01050
22	-2.0	0.0	-2.5	0.01125	60	+3.0	+5.0	+2.5	0.00225
23	-2.0	0.0	0.0	0.05250	61	+4.0	-5.0	-2.5	0.00075
24	-2.0	0.0	+2.5	0.01125	62	+4.0	-5.0	0.0	0.00350
25	-2.0	+2.0	-2.5	0.00338	63	+4.0	-5.0	+2.5	0.00075
26	-2.0	+2.0	0.0	0.01575	64	+4.0	-2.0	-2.5	0.00113
27	-2.0	+2.0	+2.5	0.00338	65	+4.0	-2.0	0.0	0.00525
28	-2.0	+5.0	-2.5	0.00225	66	+4.0	-2.0	+2.5	0.00113
29	-2.0	+5.0	0.0	0.01050	67	+4.0	0.0	-2.5	0.00375
30	-2.0	+5.0	+2.5	0.00225	68	+4.0	0.0	0.0	0.01750
31	0.0	-5.0	-2.5	0.00900	69	+4.0	0.0	+2.5	0.00375
32	0.0	-5.0	0.0	0.04200	70	+4.0	+2.0	-2.5	0.00113
33	0.0	-5.0	+2.5	0.00900	71	+4.0	+2.0	0.0	0.00525
34	0.0	-2.0	-2.5	0.01350	72	+4.0	+2.0	+2.5	0.00113
35	0.0	-2.0	0.0	0.06300	73	+4.0	+5.0	-2.5	0.00075
36	0.0	-2.0	+2.5	0.01350	74	+4.0	+5.0	0.0	0.00350
37	0.0	0.0	-2.5	0.04500	75	+4.0	+5.0	+2.5	0.00075
38	0.0	0.0	0.0	0.21000	-	-	-	-	-

Appendix B

Microgrid Operation

Table 5-3: Grid-connected mode: Excess demand profile (Scenario 61)

T	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
D	1267	1121	1012	966	850	896	1213	1653	2248	2449	2573	2805	2750	2727	2681	2542	2472	2836	3198	3191	3105	2805	2326	1746
W+PV	448	472	524	652	590	587	370	419	893	1229	1260	1268	1264	1268	1173	1074	874	707	466	511	794	898	1014	788
ND	819	649	488	314	260	309	844	1235	1355	1221	1313	1537	1486	1460	1508	1468	1598	2128	2732	2680	2312	1907	1312	958
Disp	819	649	488	314	260	309	844	1235	1355	1221	1313	1537	1486	1460	1508	1468	1598	2128	2600	2600	2300	1900	1312	958
Gin	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	132	80	12	7	0	0
Gout	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SRreq	223	207	200	210	186	191	203	265	403	472	491	522	514	512	495	465	433	459	475	481	507	481	434	329
SRavl	1381	1551	1712	1886	1940	1891	1356	1365	1245	1379	1287	1063	1114	1140	1092	1132	1002	1072	868	920	988	993	1288	1242

**T*: Time (Hr), *D*: Demand (kW), *W*: Wind power (kW), *PV*: Solar power (kW), *ND*: Net demand (kW), *Disp*: Dispatchable units' output power (kW), *Gin*: Power imported from the upstream grid (kW), *Gout*: Power exported to the upstream grid (kW), *SRreq*: Spinning reserve requirement (kW), *SRavl*: Spinning reserve available (kW).

Dispatchable units' commitment and power generation (kW) schedule:

T / U#	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1 (600)	600	549	388	214	160	209	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
2 (600)	219	100	100	100	100	100	244	535	600	521	600	600	600	600	600	600	600	600	600	600	600	600	600	358
3 (400)	0	0	0	0	0	0	0	100	155	100	113	337	286	260	308	268	398	400	400	400	400	400	112	0
4 (300)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	300	300	300	300	300	0	0
5 (300)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	228	300	300	300	0	0	0
6 (200)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	200	200	0	0	0	0
7 (100)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	100	100	0	0	0
8 (100)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	100	0	0	0	0

**T*: Time (Hr), *U#:* Dispatchable unit number (Capacity in kW).

Table 5-4: Grid-connected mode: Excess demand profile (Scenario 15)

T	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
D	1205	1066	963	919	809	853	1154	1573	2139	2330	2448	2669	2617	2595	2551	2419	2352	2698	3043	3036	2955	2669	2213	1661
W+PV	471	496	551	686	620	616	387	438	936	1289	1321	1329	1325	1329	1230	1126	917	743	490	537	834	944	1065	829
ND	734	570	412	234	189	236	767	1135	1204	1042	1127	1340	1292	1266	1321	1292	1435	1955	2553	2499	2120	1725	1147	832
Disp	734	570	412	234	200	236	767	1135	1204	1042	1127	1340	1292	1266	1321	1292	1435	1955	2553	2499	2120	1725	1147	832
Gin	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gout	0	0	0	0	11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SRreq	218	203	197	209	185	189	198	257	394	464	482	512	504	502	485	455	423	445	458	464	492	470	426	324
SRavl	1466	1630	1788	1966	2000	1964	1433	1465	1396	1558	1473	1260	1308	1334	1279	1308	1165	1245	1047	1101	1180	1175	1453	1368

**T*: Time (Hr), *D*: Demand (kW), *W*: Wind power (kW), *PV*: Solar power (kW), *ND*: Net demand (kW), *Disp*: Dispatchable units' output power (kW), *Gin*: Power imported from the upstream grid (kW), *Gout*: Power exported to the upstream grid (kW), *SRreq*: Spinning reserve requirement (kW), *SRavl*: Spinning reserve available (kW).

Dispatchable units' commitment and power generation (kW) schedule:

T / **U#**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
1 (600)	600	470	312	134	100	136	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
2 (600)	134	100	100	100	100	100	167	435	504	342	427	600	592	566	600	592	600	600	600	600	600	600	447	232
3 (400)	0	0	0	0	0	0	0	100	100	100	100	140	100	100	121	100	235	400	400	400	400	400	100	0
4 (300)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	255	300	300	300	125	0	0
5 (300)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	300	300	170	0	0	0
6 (200)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	200	199	0	0	0	0
7 (100)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	50	50	0	0	0
8 (100)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	53	50	0	0	0	0

**T*: Time (Hr), *U#:* Dispatchable unit number (Capacity in kW).

Table 5-5: Grid-connected mode: Excess renewable generation profile (Scenario 15)

T	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
D	643	568	514	490	431	455	615	839	1141	1243	1305	1423	1396	1384	1360	1290	1254	1439	1623	1619	1576	1423	1180	886
W+PV	471	496	551	686	620	616	387	438	936	1289	1321	1329	1325	1329	1230	1126	917	743	490	537	834	944	1065	829
ND	172	72	-38	-196	-189	-162	228	401	205	-46	-15	94	71	55	130	163	337	696	1133	1082	742	479	114	57
Disp	172	100	100	100	100	100	228	401	205	100	100	100	100	100	130	163	337	696	1133	1082	742	479	114	100
Gin	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gout	0	28	138	296	289	262	0	0	0	146	115	6	29	45	0	0	0	0	0	0	0	0	0	43
SRreq	145	138	138	153	136	137	128	162	264	323	334	350	346	345	330	308	280	282	273	280	313	308	292	223
SRavl	1428	1500	1500	1500	1500	1500	1372	1199	1395	1500	1500	1500	1500	1500	1470	1437	1263	1504	1067	1118	1458	1721	1486	1500

**T*: Time (Hr), *D*: Demand (kW), *W*: Wind power (kW), *PV*: Solar power (kW), *ND*: Net demand (kW), *Disp*: Dispatchable units' output power (kW), *Gin*: Power imported from the upstream grid (kW), *Gout*: Power exported to the upstream grid (kW), *SRreq*: Spinning reserve requirement (kW), *SRavl*: Spinning reserve available (kW).

Dispatchable units' commitment and power generation (kW) schedule:

T / **U#**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
1 (600)	172	100	100	100	100	100	228	401	205	100	100	100	100	100	130	163	337	596	600	600	600	379	114	100
2 (600)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	533	482	142	100	0	0
3 (400)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4 (300)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 (300)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 (200)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 (100)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 (100)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

**T*: Time (Hr), *U#:* Dispatchable unit number (Capacity in kW).

Table 5-6: Grid-connected mode: Excess renewable generation profile (Scenario 61)

T	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
D	676	597	540	515	453	478	647	882	1199	1306	1372	1496	1467	1454	1430	1355	1318	1512	1706	1702	1656	1496	1240	931
W+PV	448	472	524	652	590	587	370	419	893	1229	1260	1268	1264	1268	1173	1074	874	707	466	511	794	898	1014	788
ND	227	126	15	-137	-137	-109	277	463	306	77	112	228	203	187	257	281	445	805	1239	1190	862	598	227	143
Disp	227	126	100	100	100	100	277	463	306	100	112	228	203	187	257	281	445	805	1200	1190	862	598	227	143
Gin	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	39	0	0	0	0	0
Gout	0	0	85	237	237	209	0	0	0	23	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SRreq	146	139	138	152	135	137	130	165	266	323	335	351	347	346	332	310	283	287	281	287	318	311	293	224
SRavl	1373	1475	1500	1500	1500	1500	1323	1137	1294	1500	1488	1372	1397	1413	1343	1319	1155	1395	961	1010	1338	1602	1373	1457

**T*: Time (Hr), *D*: Demand (kW), *W*: Wind power (kW), *PV*: Solar power (kW), *ND*: Net demand (kW), *Disp*: Dispatchable units' output power (kW), *Gin*: Power imported from the upstream grid (kW), *Gout*: Power exported to the upstream grid (kW), *SRreq*: Spinning reserve requirement (kW), *SRavl*: Spinning reserve available (kW).

Dispatchable units' commitment and power generation (kW) schedule:

U# \ T	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
1 (600)	227	126	100	100	100	100	277	463	306	100	112	228	203	187	257	281	445	600	600	600	600	498	227	143
2 (600)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	205	600	590	262	100	0	0
3 (400)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4 (300)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 (300)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 (200)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 (100)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 (100)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

**T*: Time (Hr), *U#:* Dispatchable unit number (Capacity in kW).

Table 5-7: Isolated mode: Excess demand profile (Scenario 61)

T	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
D	1267	1121	1012	966	850	896	1213	1653	2248	2449	2573	2805	2750	2727	2681	2542	2472	2836	3198	3191	3105	2805	2326	1746
W+PV	448	472	524	652	590	587	370	419	893	1229	1260	1268	1264	1268	1173	1074	874	707	466	511	794	898	1014	788
ND	819	649	488	314	260	309	844	1235	1355	1221	1313	1537	1486	1460	1508	1468	1598	2128	2732	2680	2312	1907	1312	958
Disp	819	649	488	314	260	309	844	1235	1355	1221	1313	1537	1486	1460	1508	1468	1598	2128	2338	2332	2301	1907	1312	958
LS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	394	348	11	0	0	0
PC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SRreq	139	132	132	146	130	131	123	155	253	309	319	335	331	330	316	295	268	270	262	268	299	294	279	213
SRavl	381	551	712	886	940	891	356	365	545	679	587	363	414	440	392	432	302	272	262	268	299	393	288	242

**T*: Time (Hr), *D*: Demand (kW), *W*: Wind power (kW), *PV*: Solar power (kW), *ND*: Net demand (kW), *Disp*: Dispatchable units' output power (kW), *LS*: Load shedding (kW), *PC*: Power curtailment (kW), *SRreq*: Spinning reserve requirement (kW), *SRavl*: Spinning reserve available (kW).

Dispatchable units' commitment and power generation (kW) schedule:

T / U#	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1 (600)	600	549	388	214	160	209	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
2 (600)	219	100	100	100	100	100	244	535	600	471	563	600	600	600	600	600	600	600	600	600	600	600	600	358
3 (400)	0	0	0	0	0	0	0	100	105	100	100	287	236	210	258	218	348	400	400	400	400	400	112	0
4 (300)	0	0	0	0	0	0	0	0	50	50	50	50	50	50	50	50	50	300	300	300	300	157	0	0
5 (300)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	128	238	232	201	100	0	0
6 (200)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	100	100	100	0	0	0
7 (100)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	50	50	50	0	0
8 (100)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	50	50	0	0	0

**T*: Time (Hr), *U#:* Dispatchable unit number (Capacity in kW).

Table 5-8: Isolated mode: Excess renewable generation profile (Scenario 15)

T	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
D	643	568	514	490	431	455	615	839	1141	1243	1305	1423	1396	1384	1360	1290	1254	1439	1623	1619	1576	1423	1180	886
W+PV	471	496	551	686	620	616	387	438	936	1289	1321	1329	1325	1329	1230	1126	917	743	490	537	834	944	1065	829
ND	172	72	-38	-196	-189	-162	228	401	205	-46	-15	94	71	55	130	163	337	696	1133	1082	742	479	114	57
Disp	172	72	50	50	50	50	228	401	205	100	100	100	100	100	130	163	337	696	1133	1082	742	479	114	100
LS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PC	0	0	88	246	239	212	0	0	0	146	115	6	29	45	0	0	0	0	0	0	0	0	0	43
SRreq	102	100	104	120	107	107	87	106	188	240	247	255	253	252	240	222	196	186	165	172	208	213	213	164
SRavl	228	228	250	250	250	250	372	199	395	500	500	500	500	500	470	437	863	504	467	518	858	721	486	500

**T*: Time (Hr), *D*: Demand (kW), *W*: Wind power (kW), *PV*: Solar power (kW), *ND*: Net demand (kW), *Disp*: Dispatchable units' output power (kW), *LS*: Load shedding (kW), *PC*: Power curtailment (kW), *SRreq*: Spinning reserve requirement (kW), *SRavl*: Spinning reserve available (kW).

Dispatchable units' commitment and power generation (kW) schedule:

U# \ T	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1 (600)	0	0	0	0	0	0	178	351	205	100	100	100	100	100	130	163	237	596	600	600	542	379	114	100
2 (600)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	100	433	382	100	100	0	0
3 (400)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	100	100	0	0	0
4 (300)	122	72	50	50	50	50	50	50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 (300)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 (200)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 (100)	50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 (100)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

**T*: Time (Hr), *U#:* Dispatchable unit number (Capacity in kW).

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