Optimal power management of dependent microgrid considering distribution market and unused power capacity

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Abstract – This study presents an optimal power management for a microgrid (MG) in distribution market environment. The MG operator is able to have an interaction with the distribution market operator (DMO) and adjacent MG (AMG) operator to supply its local loads. The DMO regulates the electricity market, and assigns the electricity price and power profile for the MG. The motivation behind the use of The DMO is that it works as an entity between MG and independent system operator (ISO) in order to guarantee a flexible operation by reducing power fluctuation and reduce the unintentional peak loads in low market price hours. The unused power capacity in AMG is used during the islanded hours through an additional interconnection point connected to the MG. Using this method reduces the need for installing new generation resources, which will be a practical and economical solution for MG developer. This MG which is able to provide power from distribution market and the AMG with two interconnection points is named dependent MG (DMG). A market-based stochastic model containing distribution market constraints and AC power flow formulations employs conditional value at risk (CVaR) methodology to capture the loads and wind uncertainties.

The effectiveness of the presented model is evaluated on a 20 kV test system using different case studies. In this test system, the operator is the owner of all generation units. The numerical analysis explicate that the model reduces the operation cost of DMG with the aim of responsive loads, unused power capacity, energy storage system (ESS) and power generation units. The market-based scheduling also provides operational flexibility for distribution system by adjusting flexibility limit of market constraints. It is also shown that changing risk preferences level changes the power generation pattern in ESS and causes a costly operation of resources in risk-averse strategy. The competence of this model is significant when the preventive maintenance (PM) program is carried out, and the DMG should just rely on its local flexible resources and AMG's available power capacity. Moreover, it is discussed that the available unused power capacity in AMG can prevent DMG from load shedding during the inaccessibility of DMG to the upstream network.

Keywords – Adjacent Microgrid (AMG), Dependent Microgrid (DMG), Distribution Market Operator (DMO), Power Management, Risk Constraints, Unused Power Capacity

Nomenclature

Sets and Indexes

t	Index of the time horizon (1 … T)
s	Index of each scenario (1 … Ω)
n, m	Index of buses (1 … N)
j	Index of dispatchable units (1 … J)
l	Index of lines (1 … L)

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b	Index of responsive industrial loads (1 … B)
ξ	Index of responsive industrial load steps
e	Index of storage units (1 … E)
w	Index of wind turbines (1 … W)
cc	Set of capacitors

Parameters

$P_{max}^{RT}, P_{min}^{RT}$	Maximum/minimum real-time active power transfer of main grid
$Q_{max}^{RT}, Q_{min}^{RT}$	Maximum/minimum real-time reactive power transfer of main grid
P_t^M, Q_t^M	Main grid active/reactive power transfer assigned by DMO
$p_{max}^{n,m}, p_{min}^{n,m}$	Maximum/minimum active power transfer of lines
$q_{max}^{n,m}, q_{min}^{n,m}$	Maximum/minimum reactive power transfer of lines
$Q_{n,cc}^{shunt}$	Reactive generated power of capacitor cc at bus n
UR_j, DR_j	Ramp up/down rate of dispatchable unit j
UT_j, DT_j	Minimum up/down time of dispatchable unit j
MC_e, MD_e	Minimum charging/discharging hours of ESS e
l_ξ^b	Accepted amount of industrial demand reduction
$A_{n,l}$	Element of bus-line matrix (1 for sending bus, -1 for receiving bus, 0 otherwise)
$A'_{n,l}$	Element of modified bus-line matrix (1 for sending bus, and 0 otherwise)
b_l, g_l	Imaginary/ real parts of admittance of line l
x_l, r_l	Imaginary/ real parts of impedance of line l
ρ_t^M	Electricity price at common coupling point
ρ_t^{AMG}	Negotiated electricity price with AMG
$IC_{n,t,\omega}^b$	Encouraging cost for involvement of industrial consumer b at bus n
o_ξ^b	Monetary offered by industrial participant b at step ξ
$\Gamma_{t,s}$	Encouraging financial offer for residential consumer
C	Penalty cost of deviation from assigned power
k	Proportion of active power price
R	Flexibility limit
$VOLL_n$	Value of lost load at bus n
η	Operation efficiency of ESS
$prob_s$	Happening probability of scenario s

Variables

$I_{j,t}$	Commitment indicator of dispatchable units (1/0 for committed/otherwise)
v_t	ESS charging indicator (1 for charging states, 0 otherwise)
u_t	ESS discharging indicator (1 for discharging states, 0 otherwise)
$um_{t,s}$	Main grid availability indicator (1/0 when the main grid is available/ unavailable)
$uc_{t,s}$	AMG's availability indicator (1/0 when AMG is available/ unavailable)
$x_{t,s}$	Power deviation indicator (0 for deviated, 1 otherwise)
$P^{wind}_{w,t,s}$	Generation power of wind turbine
$P^{RT}_{t,s}, Q^{RT}_{t,s}$	Main grid real-time active/reactive power transfer
$P^{AMG}_{t,s}, Q^{AMG}_{t,s}$	Procured active/reactive power from AMG
$\Delta P_{t,s}, \Delta Q_{t,s}$	Main grid active/reactive power transfer deviation with respect to the assigned profile
$\Delta P^{+}_{t,s}, \Delta Q^{+}_{t,s}$	Positive active/reactive power transfer mismatch of main grid
$\Delta P^{-}_{t,s}, \Delta Q^{-}_{t,s}$	Negative active/reactive power transfer mismatch of main grid
$p^{loss}_{l,t,s}, q^{loss}_{l,t,s}$	Active /reactive loss of line l
$p^{Send}_{l,t,s}, q^{Send}_{l,t,s}$	Sending active/reactive power of line l
$p^{Receive}_{l,t,s}, q^{Receive}_{l,t,s}$	Receiving active/reactive power of line l
$p^{n.m}_{t,s}, q^{n.m}_{t,s}$	Active/reactive power flow between buses n and m
$P^{DU}_{j,t,s}, Q^{DU}_{j,t,s}$	Generated active/reactive power of dispatchable unit j
$P^{Load}_{n,t,s}, Q^{Load}_{n,t,s}$	Active/reactive demand at bus n
$P^{LS}_{n,t,s}, Q^{LS}_{n,t,s}$	Active/reactive load shedding at bus n
$IP^{b}_{n,t,s}, IQ^{b}_{n,t,s}$	Diminished active/reactive industrial demand b at bus n
$ReP_{n,t,s}, ReQ_{n,t,s}$	Diminished active/reactive residential demand at bus n
$T^{ch}_{e,t}, T^{dch}_{e,t}$	Successive number of charging/discharging hours for ESS e
$T^{on}_{j,t}, T^{off}_{j,t}$	Successive Number of on/off hours for dispatchable unit j
$\phi_{n,t,s}, V_{n,t,s}$	Angle/ Root mean square voltage of bus n
β, α	Risk parameters

1 Introduction

1.1 Literature review

In recent years, various types of renewable energy sources (RESs) and energy storage systems (ESSs) have attracted the attentions in order to reduce the carbon emission in the environment. Due to the high penetration of these valuable resources besides responsive loads in power systems, a practical solution should be used to optimally manage these generation and consumption units [1]. Nowadays, Microgrids (MGs) are introduced to solve the energy management challenges in power network. MGs are independent systems comprised of distributed energy resources (DERs), responsive and fixed loads as well as ESS, which can be managed in connected and islanded modes of operation [2]. Islanded operation of MGs is the most remarkable feature of them, which can be initiated by several causes such as equipment failure of main grid, weather-related incidents, voltages and frequency fluctuations as well as preventive maintenance (PM) programs of substations and lines [3]-[4].

Over the recent decade, the deployment of MGs in the electrical power grid has been intensified, and scholars predict that installation of MGs distributes significantly in different countries in the near future [5]. Hence, it would be so crucial that MG operators use an efficient control, management and optimization strategies which are investigated in [6]. There are three hierarchical control levels, which the primary and secondary levels address to the droop control and voltage/frequency restoration and adjustment, while an incident like a sudden fluctuation of the consumption or power generation as well as the islanding transition happens in the power network [7]. At the third control level, MG operator is able to optimally schedule the power resources using economic dispatch (ED) problem [8]. In this level, optimal decisions are taken to minimize the costs of power exchange with the main grid and DERs' operation, to satisfy customers' electrical demand in a short horizon [9]. There have been two designs named centralized and decentralized for MG control architecture. Centralized architecture poses central computing unit exercised for scheduling and has access to the power generation and consumption information [10]. In contrast, using decentralized control, each participant plays as an agent possessing interaction with other agents [11]. It is to be mentioned that centralized control framework is more practical for MG optimal scheduling, and it facilitates the optimization procedure to attain the optimum results. Considering economic perspective, centralized architecture also does not require monetary investments to build the communication infrastructures.

Researchers have scrutinized plenty of methods to solve short-term scheduling problems, containing stochastic, deterministic, and heuristic methods. Inevitable uncertainties are also considered in the day-ahead scheduling of electrical energy systems, using risk-taking stochastic programming [12]–[13], risk-averse stochastic formulation [14]–[15], and robust optimization [16]–[17]. A comprehensive AC or DC power flow simulation has been neglected in the mentioned references, while they just propose a simple balance equation showing sum of power from the main grid and the power generated by DERs matches the total loads. There exist references [18]–[19], implementing AC power flow equations to provide a thorough and realistic operation model for MGs, but the influences of risk constraints are not analyzed on decision making procedure in the presence of diverse uncertainties.

Since the penetration of MGs containing responsive loads and power generation has increased in power system, the demand-side elasticity has also intensified [20]. Unfortunately, the price-based scheduling is still commonly used for optimal scheduling of MGs. In price-based framework, forecasted load in MG is submitted to the upstream utility, and after clearing wholesale market and determining the electricity price, the utility submits the finalized price signals to each MG. Since the power consumption of MGs and also independent responsive demands are inversely proportional to price signals, price-based scheduling leads to new peaks in the power network because the downside responsive demands are inclined to buy the electrical power in low price hours. It is likely that the unintentional peak load reinforces severely in the presence of remarkable number of price-responsive demands [21]. This operation challenge, combined with increasing penetration of MGs in upcoming years, should encourage us to exercise a new model for MG optimal scheduling.

Stochastic market-based scheduling of MG is suggested in [22]; however, risk of uncertainties and physical constraints of MG network have not been considered. In the market-based pricing approach, which investigates in [22], MG submits its demand signal to the distribution market operator (DMO), then DMO sends this demand to the independent system operator (ISO). DMO is known as an autonomous player in distribution level to manage the interactions between the MG operator and ISO in electricity market environment. ISO is responsible for determining the market price and demand for MGs in 24-h. DMO will receive day-ahead schedule from ISO, and send the determined price and demand to the MGs. In fact, MG operator cannot determine its desirable demand and it will be imposed by DMO to handle peak load challenges and sharp violation of power in low market price hours [23]. Also, a thorough comparison is made between price-based and market-based scheduling of MG in [23], while the economics influences of demand response (DR) resources and RESs are not studied in it. Reference [23] demonstrates that the market-based scheduling forces operator to buy more power from the upstream network in order to flatten the peak load, which leads to the fewer commitment of conventional DGs. Although fewer committed DGs would reduce the fossil fuel pollutions, this issue can provide a significant amount of unused power capacity in power system. Also, researchers consider the unused capacity of coupled MGs, and introduce a renewable based MG named provisional MG as a viable solution to procure power from the upstream grid and coupled MGs which have unused power capacity [17]. In this regard, reference [24] investigates the positive role of MG on the flexibility improvement of the distribution system operation. Recently, the connectivity of the group of MGs has attracted the attentions, and reference [25] discusses a novel power routing algorithm among connected MGs to enhance the flexibility of operation.

In [26], dependent MG (DMG) which can provide power from the adjacent MG (AMG) in islanded hours is introduced. However, a market-based scheduling is not studied in [17] and [26].

It is evident that in market-based strategy, the unused capacity in power system would increase in comparison with price-based policy, so a practical solution is needed to enjoy the advantages of both flexible market-based scheduling and the unused capacity of AMGs.

1.2 Objectives and contributions

Investigating the existing researches, there is not a thorough model that has been implemented for the optimal power management scheduling of MGs in the presence of DMO and unused capacity of AMGs. In addition, from mathematical perspective, an efficient and economic policy has not been suggested for addressing common uncertainties. References [27]–[28] use worst scenarios in MG scheduling which simplifies the simulation procedure and data preparation; however, it would not guarantee a realistic scheduling method, and it would lead to the costly and conservative decisions for MG scheduling.

In this paper, a market-based stochastic scheduling of DMG is proposed to address the upcoming challenges of MGs' penetration in power system and to guarantee a flexible and economic operation during the day. This method addresses a day-ahead DMG power management scheduling from operator's perspective in the presence of responsive loads, RESs, ESS and dispatchable power generation resources. Risk constraints are also employed to satisfy an economic tradeoff between realistic and conservative decisions considering load and wind uncertainties. Moreover, the upstream substation which needs PM program for improving the operational reliability of its buses, transformers, circuit breakers or lines may not be able to provide the MG's required power because of some predetermined outages in PM program, so the DMG should be disconnected from the upstream grid, and rely on its own installed resources and the unused capacity of AMG.

In Table 1, the most pertinent references to the presented work are tabulated. For each works, it is displayed that whether the items written in the first column of the table were taken in to account or not.

Table 1. Differences of the most pertinent studies with the current study

References	[12]	[14]	[18]	[19]	[22]	[26]	Current study
Islanded operation	✓	✓	×	×	✓	✓	✓
Responsive loads	✓	✓	✓	✓	✓	✓	✓
Risk constraints	×	✓	×	×	×	✓	✓

AC optimal power flow	×	×	✓	✓	×	✓	✓
Market-based scheduling	×	×	×	×	✓	×	✓
Unused capacity of MGs	×	×	×	×	×	✓	✓

There is no research study that has optimized the MG operation cost in the presence of distribution market constraints, unused capacity of AMG, AC power flow formulations, responsive loads, risk constraints and flexibility limit as well as the islanding capability. According to the mentioned drawbacks, the key contributions of this study can be summarized as follows:

- Developing a market-based stochastic scheduling based on the DMO and risk constraints as well as flexibility limit;
- Considering the unused power capacity of AMG in day-ahead power management scheduling;
- Using the comprehensive linearized AC power flow formulations to satisfy network security;
- Investigating the operational role of responsive loads, dispatchable units, flexibility limit and ESS in the presence of uncertainties associated with load and RESs ;

The rest of the paper is arranged as follows. Section 2 reviews the components of the power management scheduling model. Section 3 formulate the scheduling problem. Numerical analysis and results are given in Section 4, and Section 5 concludes the study.

2 Conceptual model

A day-ahead optimal scheduling of DMG considering the DMO, responsive loads, flexible power resources and unused capacity of AMGs is presented in this paper. The exhaustive interactions and constituents of the DMG are described as follows:

2.1 Distribution market

Distribution market, an independent entity at distribution system level, is proposed to provide a competitive interaction between ISO and demand side participants. Its operator named DMO ensures power transaction with ISO and lower side participants of market in order to improve power system flexibility and reliability. This operator simplifies the remarkable integration of MGs and responsive loads from the ISO's viewpoint because the upstream operator just receives an aggregated demand from lower level with the aim of DMO [22]. In other words, DMO collects several demand bids from MGs' operators, and combines them to submit an aggregated bid to the ISO. These aggregated demand bids and generation bids of generation companies at upper level are received by ISO to calculate the electricity price. Moreover, after executing the market clearing and assigning power schedule of each connected player for 24-h, MG shares are determined through the DMO from the awarded electrical power of ISO [23]. As a result, the amount of the power transfer to the MG is reported to its operator, which eliminates high percentage of uncertainties and flatten the demand profile [21]. This efficient market-based strategy not only does address the deficiencies of price-based operation, but also determines the demand of MG as a certain value in the scheduling horizon, which can facilitate the mathematical scheduling process. Figure 1 demonstrates the power purchases and awarded bids of different MGs during the interaction with ISO and DMG. However, our under study MG is DMG shown in the figure and the scheduling problem will be solved from its perspective.

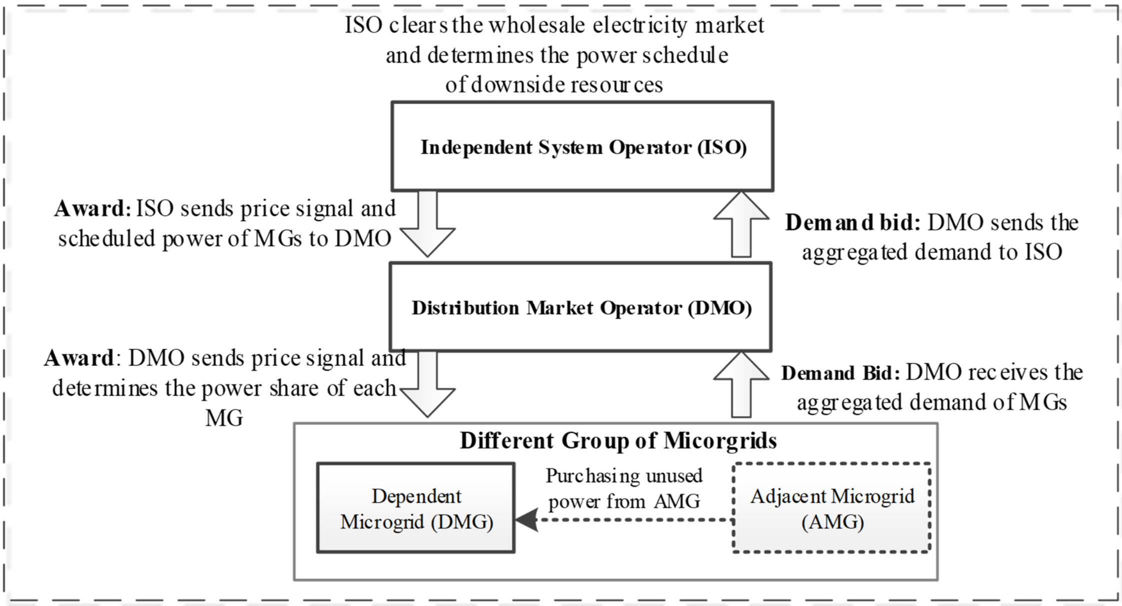

Fig. 1. Proposed MGs' interaction with upstream level of power system

2.2 Unused capacity of AMGs

One of the most important features of MG is the islanded operation while a disturbance happens in upstream grid. This feature ensures the reliability and economic advantages for both consumers and power grid. However, this capability has also some practical problems because of increasing penetration of MGs in power system. MGs need the installation of dispatchable power generation units to provide electrical power for consumers in islanded hours. Since the main grid electricity price is commonly cheaper than the operation cost of dispatchable units [29], a significant amount of power is procured from the upstream rather than local generation units when the MGs are connected to the network. Therefore, the installed units are mostly utilized in islanded hours for satisfying power and supply balance. It means that there exists a significant amount of unused power capacity which is provided by dispatchable units in connected mode of operation. On the other hand, recently, researchers have found that the market-based scheduling of MGs with the participation of DMO would increase the power shares of main grid to reduce sharp peak loads and commitments of dispatchable units [23]. Unfortunately, this issue also intensifies the unused power capacity of dispatchable units; hence, there should be a viable solution to take advantages from this power capacity.

A MG with an extra interconnection point named dependent MG is able to provide an electrical energy from unused capacity of AMGs when the main grid is inaccessible [26]. AMGs, known as electrically-tied MGs, are common MGs with a high penetration of dispatchable units, so AMGs can sell their additional power to DMG in islanded hours. It may be that the sufficient energy is not available for DMGs in some hours, so DMG also should be able to get benefit from responsive loads and load shedding program to meet the its demand.

2.3 Responsive loads

Responsive loads act as reserve resources for MGs to meet the power shortages caused by main grid failures, forecast errors and generation deficiency of RESs. Different daily consumption patterns are imposed to MG scheduling procedure by different electricity consumers such as industrial and residential consumers which are taken into account in this study. They are determined as an active player in the DR programs to modify the load profile during a day. The Incentive-based program is one of the most practical DR program, which is implemented in MG operation studies. In this program, the customers are motivated by monetary benefits to take part in daily scheduling program. The interruptible/curtailable program (I/C program), as one of the incentive program types, provides incentive for customers so that they can reduce their consumption during scheduling horizon [12].

2.4 Uncertainties

During the scheduling procedure, DMG operator encounters uncertainty of loads and wind turbines' power output. Various methods for simulating the uncertainties will address in the followings:

According to the historical data of some specific patterns like prices and wind, scenarios can be generated with the aim of the practical tool named autoregressive moving-average (ARMA) [30]. The ARMA (x,y) model shown in (1) has a complex linear function of the past values and noise parameter, which enables us to dignify the future pattern.

$$z_t = \varepsilon_t - \sum_{i=1}^{y} \Theta_i \varepsilon_{t-i} + \sum_{i=1}^{x} \Phi_i z_{t-i} \tag{1}$$

In this function, Ɛ, y, and x are associated with the uncorrelated stochastic procedure, moving average parameters $\theta_1, \theta_2 \ldots \theta_y$, and autoregressive parameters $\phi_1, \phi_2 \ldots \phi_x$, respectively. Furthermore, the uncorrelated stochastic process denotes to the white noise through the zero mean and σ_ε^2 variance [24].

The load profile depends on the weather condition during a day and social events. It is evident that the consumption patterns of consumers on the weekends are by far different to the regular days. The Gaussian probability distribution function presented in (3) is an accurate method to simulate uncertain parameters of daily demands [13]. Both σ and μ are represented as the standard and average deviation of demands' historical data (l).

$$f_d(l) = (\frac{1}{\sigma\sqrt{2\pi}}) \times \exp(-\frac{(l-\mu)^2}{2\sigma^2}) \quad (2)$$

Using the discussed methods for generating scenarios, a vector of 1000 scenarios for 24-h horizon is provided with the equal probability of occurrence. Determining a reasonable number of scenarios is vital to ensure the accuracy and to diminish the computational times of scheduling. The number of scenarios is reduced through the forward methodology in SCENRED tool of GAMS [31]. As a result, these reduced scenarios make a compromise between the complexity of the problem and the precision of the final results. Figure 2 shows the scenario generation flowchart for all uncertainties.

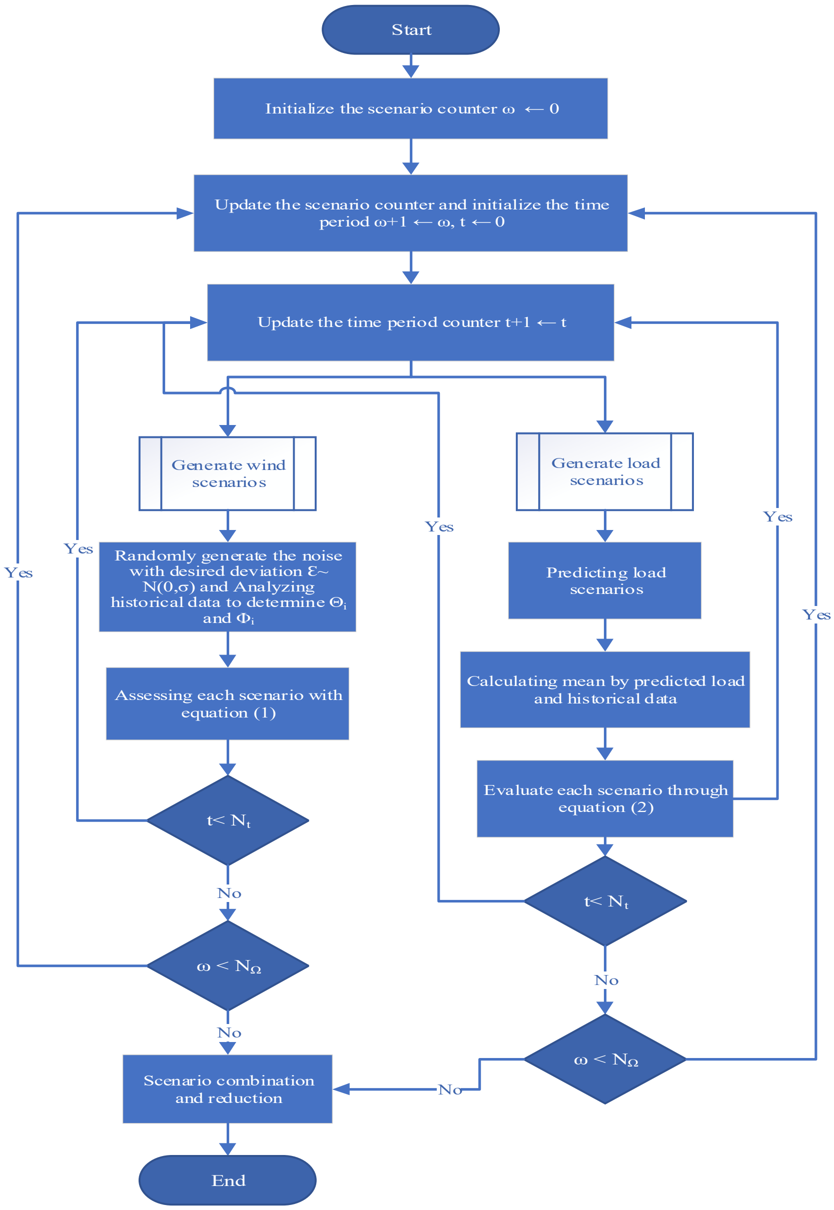

Fig. 2. Flowchart of scenario generation

2.5 Power management scheduling outline

MG operator is willing to find the least-cost decisions in power scheduling program. This point is taken in to account in this study while considering uncertainties associated with residential load and wind turbines power. A considerable number of scenarios accompanied with uncertain parameters is generated and then reduced through reduction techniques to guarantee a feasible and efficient mode. In this research study, risk constraints are added to the stochastic programming in order to mitigate the effects of uncertainties bringing about expensive operation cost.

After the DMG operator sends the required demand signal to the DMO one day ahead, the DMO would specify the market price and the accepted demand for DMG after receiving the market clearing results from ISO. Then, the DMG operator solves the scheduling problem through the accepted demand profile which reduces operational uncertainties. It is to be mentioned that the deviations from the determined demand profile would be penalized by a pre-determined value named deviation penalty. This penalty is just considered in operation cost whenever the deviation is positive, i.e., the real-time power transfer is greater than the assigned profile. Also, the deviation should be controlled by flexibility limits which is determined by the DMO. Figure 3 demonstrates the market-based power management scheduling of DMG. In this figure, the certain and uncertain input data are shown. It is also demonstrated that how the required data are obtained. At the mediator level, the stochastic approach is presented, and shown that the flexibility limit and risk parameters are influential before making an optimal decisions. In here and now decisions, the commitment states of dispatchable units and ESS charging/discharging programs are determined. Decisions at the wait and see stage are associated with the deviation of the real time power from the determined power of DMO according to the flexibility limit, economic dispatch of ESS and dispatchable units, responsiveness of loads, purchased power from the unused capacity of AMG, and load shedding. The mathematical elucidation of the objective function and constraints are described in the next section.

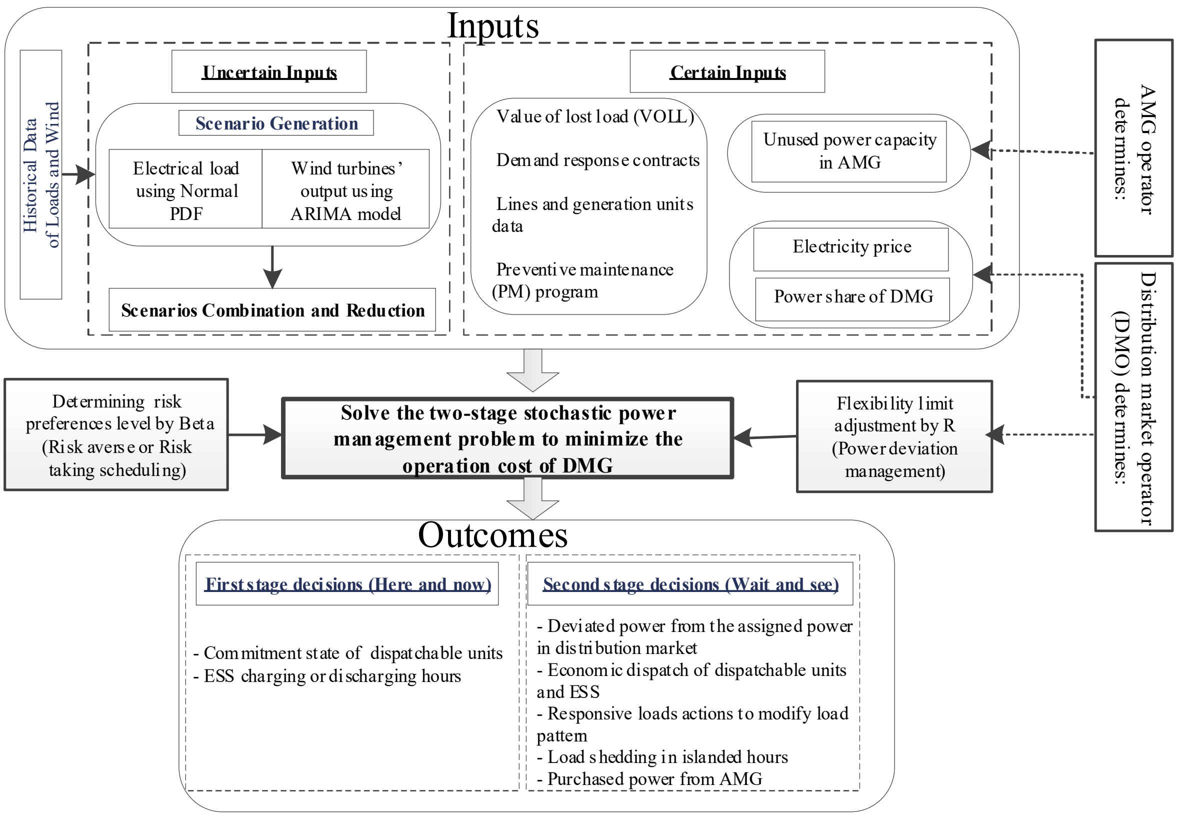

Fig. 3. Presented outline for DMG power management scheduling

3 Problem formulation

The market-based power management scheduling of DMG is formulated as a mixed-integer linear programming (MILP). The objective of this problem and the relevant constraints are explained as follows:

3.1 Objective function

The objective function in (3a)–(3b) is to minimize the operation cost over the scheduling horizon in DMG, including, the penalty for deviation from assigned power profile, cost for procuring power from AMG, operation costs of dispatchable units, load shedding prices and participation cost of industrial and residential loads in DR program. It is to be noted that the cost of power transactions with DMO has fixed amount because the power profile and prices are determined by DMO before starting scheduling horizon, and the operator is not able to optimize them during the scheduling.

$$EOC = \mathrm{Min}\sum_{t=1}^{T}\sum_{s=1}^{\Omega} prob_s\, C(s) \tag{3a}$$

$$C(s) = c\Delta P^{+}_{t,s} + \rho^{AMG}_{t} P^{AMG}_{t,s} + \sum_{g\in G} F(P^{DU}_{g,t,s}) + \sum_{n\in N} P^{LS}_{n,t,s} VOLL_n + \sum_{b\in B} IC^{b}_{n,t,s} + \sum_{n\in N} ReP_{n,t,s}\Gamma_{t,s} \tag{3b}$$

3.2 Constraints

The technical and economic constraints of power management scheduling are as follow*:*

1) distribution market constraints

The DMO is responsible for the scheduling and determining the upstream power that can be transferred to the DMG. However, the DMG operator can violate the specified power profile and pay the deviation penalty as presented in (4a)–(4j).

$$P^{RT}_{min} um_{t,s} \le P^{RT}_{t,s} \le P^{RT}_{max} um_{t,s} \tag{4a}$$

$$Q^{RT}_{min} um_{t,s} \le Q^{RT}_{t,s} \le Q^{RT}_{max} um_{t,s} \tag{4b}$$

$$\Delta P_{t,s} = P^{RT}_{t,s} - P^{M}_{t} \tag{4c}$$

$$\Delta Q_{t,s} = Q^{RT}_{t,s} - Q^{M}_{t} \tag{4d}$$

$$\Delta P_{t,s} = \Delta P^{+}_{t,s} - \Delta P^{-}_{t,s} \tag{4e}$$

$$\Delta Q_{t,s} = \Delta Q^{+}_{t,s} - \Delta Q^{-}_{t,s} \tag{4f}$$

$$0 \le \Delta P^{+}_{t,s} \le R(1 - x_{t,s}) \tag{4g}$$

$$0 \le \Delta P^{-}_{t,s} \le R x_{t,s} \tag{4h}$$

$$0 \le \Delta Q^{+}_{t,s} \le R(1 - x_{t,s}) \tag{4i}$$

$$0 \le \Delta Q^{-}_{t,s} \le R x_{t,s} \tag{4j}$$

Constraints (4a)–(4b) exhibit the active and reactive power transfer from the main grid. The binary variable $um_{t,s}$ is to simulate the islanding operation by zeroing out the upstream power transfer. The power transfer violation of the upper-level grid from the DMO power profile is set by (4c) and (4d). If the mismatch of power transfer is positive, the objective function is penalized, where $x_{t,s}$=0 and $\Delta P^{+} = \Delta P\,, \Delta Q^{+} = \Delta Q$ using (6e)–(6j). R is a positive flexibility limit which denotes the upper-limit deviation of real-time power transfer. Hence, it is a limit on DMG power exchange with upstream to capture the power fluctuations [24].

2) AMG constraints

Constraints (5a)–(5b) indicate limitations on the imported active and reactive power from the AMG. Binary variables in these constraints determine that whether the power would be purchased from the AMG. In this regard, constraint (5c) dignifies the switching capability of DMG during the main grid outages, so the operator can compensate power deficiency by connecting to AMG. For instance, when the $um_{t,s}$ is set to zero in islanding hours, the DMG is able to provide its required power from AMG power by setting $uc_{t,s}$ to 1.

$$\mathrm{P}_{\min}^{\mathrm{AMG}} \mathrm{uc}_{\mathrm{t,s}} \le \mathrm{P}_{\mathrm{t,s}}^{\mathrm{AMG}} \le \mathrm{P}_{\max}^{\mathrm{AMG}} \mathrm{uc}_{\mathrm{t,s}} \tag{5a}$$

$$\mathrm{Q}_{\min}^{\mathrm{AMG}} \mathrm{uc}_{\mathrm{t,s}} \le \mathrm{Q}_{\mathrm{t,s}}^{\mathrm{AMG}} \le \mathrm{Q}_{\max}^{\mathrm{AMG}} \mathrm{uc}_{\mathrm{t,s}} \tag{5b}$$

$$\mathrm{uc}_{\mathrm{t,s}} + \mathrm{um}_{\mathrm{t,s}} \le 1 \tag{5c}$$

3) Active and reactive power balances

The active and reactive power balances in PCC bus are indicated by equations (6a) and (6b) in which DMG links to the main network. For the other buses of DMG, the power generation and consumption balances are the same as (6c) and (6d). Moreover, the power balance equations at bus 9 have additional term, indicating the procured power from AMG.

$$\mathrm{P}_{\mathrm{t,s}}^{\mathrm{RT}} - \sum_{\mathrm{l}\in \mathrm{L}} \mathrm{A}_{\mathrm{n,l}} \mathrm{p}_{\mathrm{l,t,s}}^{\mathrm{Send}} - \sum_{\mathrm{l}\in \mathrm{L}} \mathrm{A}_{\mathrm{n,l}}^{'} \mathrm{p}_{\mathrm{l,t,s}}^{\mathrm{loss}} = 0 \; ; \; \mathrm{n} = 1 \tag{6a}$$

$$\mathrm{Q}_{\mathrm{t,s}}^{\mathrm{RT}} - \sum_{\mathrm{l}\in \mathrm{L}} \mathrm{A}_{\mathrm{n,l}} \mathrm{q}_{\mathrm{l,t,s}}^{\mathrm{Send}} - \sum_{\mathrm{l}\in \mathrm{L}} \mathrm{A}_{\mathrm{n,l}}^{'} \mathrm{q}_{\mathrm{l,t,s}}^{\mathrm{loss}} = 0 \; ; \; \mathrm{n} = 1 \tag{6b}$$

$$\begin{aligned} &\sum_{\mathrm{j}\in \mathrm{J_n}} \mathrm{P}_{\mathrm{n,j,t,s}}^{\mathrm{DU}} + \sum_{\mathrm{e}\in \mathrm{E_n}} \mathrm{P}_{\mathrm{n,e,t,s}}^{\mathrm{ESS}} + \sum_{\mathrm{w}\in \mathrm{W_n}} \mathrm{P}_{\mathrm{n,w,t,s}}^{\mathrm{wind}} - \sum_{\mathrm{l}\in \mathrm{L}} \mathrm{A}_{\mathrm{n,l}} \mathrm{p}_{\mathrm{l,t,s}}^{\mathrm{Send}} \\ &- \sum_{\mathrm{l}\in \mathrm{L}} \mathrm{A}_{\mathrm{n,l}}^{'} \mathrm{p}_{\mathrm{l,t,s}}^{\mathrm{loss}} - \mathrm{P}_{\mathrm{n,t,s}}^{\mathrm{Load}} + \mathrm{IP}_{\mathrm{n,t,s}}^{\mathrm{b}} + \mathrm{ReP}_{\mathrm{n,t,s}} + \mathrm{P}_{\mathrm{n,t,s}}^{\mathrm{LS}} = 0 \; ; \; \forall \mathrm{n} \ne 1 \end{aligned} \tag{6c}$$

$$\begin{aligned} &\sum_{\mathrm{j}\in \mathrm{J_n}} \mathrm{Q}_{\mathrm{n,j,t,s}}^{\mathrm{DU}} + \sum_{\mathrm{cc}\in \mathrm{Capacitors}} \mathrm{Q}_{\mathrm{n,cc}}^{\mathrm{Shunt}} - \sum_{\mathrm{l}\in \mathrm{L}} \mathrm{A}_{\mathrm{n,l}} \mathrm{q}_{\mathrm{l,t,s}}^{\mathrm{Send}} - \sum_{\mathrm{l}\in \mathrm{L}} \mathrm{A}_{\mathrm{n,l}}^{'} \mathrm{q}_{\mathrm{l,t,s}}^{\mathrm{loss}} \\ &- \mathrm{Q}_{\mathrm{n,t,s}}^{\mathrm{Load}} + \mathrm{IQ}_{\mathrm{n,t,s}}^{\mathrm{b}} + \mathrm{ReQ}_{\mathrm{n,t,s}} + \mathrm{Q}_{\mathrm{n,t,s}}^{\mathrm{LS}} = 0 \; ; \forall \, \mathrm{n} \ne 1 \end{aligned} \tag{6d}$$

4) *Linearizing description of power flow equations*

The linearizing procedure of AC power flow equations are presented in the following. By means of this procedure, the active/reactive power flow equations at sending and receiving buses of the line l, connecting bus n to bus m, are expressed as (7a)–(7d).

$$p_{l,t,s}^{Send} = g_l V_{n,t,s}^2 - g_l V_{n,t,s} V_{m,t,s} \cos\left(\phi_{n,t,s} - \phi_{m,t,s}\right) - b_l V_{n,t,s} V_{m,t,s} \sin\left(\phi_{n,t,s} - \phi_{m,t,s}\right) \tag{7a}$$

$$p_{l,t,s}^{Receive} = -g_l V_{m,t,s}^2 - g_l V_{m,t,s} V_{n,t,s} \cos\left(\phi_{m,t,s} - \phi_{n,t,s}\right) - b_l V_{m,t,s} V_{n,t,s} \sin\left(\phi_{m,t,s} - \phi_{n,t,s}\right) \tag{7b}$$

$$q_{l,t,s}^{Send} = -b_l V_{n,t,s}^2 - g_l V_{n,t,s} V_{m,t,s} \sin\left(\phi_{n,t,s} - \phi_{m,t,s}\right) - b_l V_{n,t,s} V_{m,t,s} \cos\left(\phi_{n,t,s} - \phi_{m,t,s}\right) \tag{7c}$$

$$q_{l,t,s}^{Receive} = b_l V_{m,t,s}^2 - g_l V_{m,t,s} V_{n,t,s} \cos\left(\phi_{m,t,s} - \phi_{n,t,s}\right) - b_l V_{m,t,s} V_{n,t,s} \sin\left(\phi_{m,t,s} - \phi_{n,t,s}\right) \tag{7d}$$

At the first stage of the linearizing, equation (8) is estimated. This is because the voltage magnitudes are around the one per unit and $\phi_{n,t,s} - \phi_{m,t,s}$ is numerically negligible.

$$V_{n,t,s} V_{m,t,s} \sin\left(\phi_{n,t,s} - \phi_{m,t,s}\right) = \phi_{n,t,s} - \phi_{m,t,s} \tag{8}$$

The relation between sending and receiving power exchange as well as losses in a line could be expressed as (9a) and (9b).

$$p_{l,t,s}^{Send} = p_{l,t,s}^{Receive} + p_{l,t,s}^{loss} \tag{9a}$$

$$q_{l,t,s}^{Send} = q_{l,t,s}^{Receive} + q_{l,t,s}^{loss} \tag{9b}$$

Implementing equations (7a)–(9b) and the detailed substitutions presented in [32], the power flows are attained as:

$$p_{l,t,s}^{Send} = \frac{1}{2}(g_l V_{n,t,s}^2 - g_l V_{m,t,s}^2) + \frac{1}{2} p_{l,t,s}^{loss} - b_l \phi_{n,t,s} + b_l \phi_{m,t,s} \tag{10a}$$

$$p_{l,t,s}^{Receive} = -\frac{1}{2}(g_l V_{m,t,s}^2 - g_l V_{n,t,s}^2) - \frac{1}{2} p_{l,t,s}^{loss} + b_l \phi_{m,t,s} + b_l \phi_{n,t,s} \tag{10b}$$

$$q_{l,t,s}^{Send} = -\frac{1}{2}(b_l V_{n,t,s}^2 - b_l V_{m,t,s}^2) + \frac{1}{2} q_{l,t,s}^{loss} - g_l \phi_{n,t,s} + g_l \phi_{m,t,s} \tag{10c}$$

$$q_{l,t,s}^{Receive} = \frac{1}{2}(b_l V_{m,t,s}^2 - b_l V_{n,t,s}^2) - \frac{1}{2} q_{l,t,s}^{loss} + g_l \phi_{m,t,s} + g_l \phi_{n,t,s} \tag{10d}$$

The formulations are still non-linear because of the square bus voltage magnitudes. Since the voltage magnitude at each bus is around one per unit, Taylor series can be used to provide linear formulas based on the definition proposed in (11). Consequently, equations (10a)–(10d) are written as (12a)–(12d). On the other hand, power losses of line *l* are non-linear equations shown in (13a)–(13b). The quadratic terms can be substituted with linear function according to the linearization strategy investigate in [33]. Finally, the acquired linear formulations with respect to the objective function are solved by the linear commercial software with high computational effectiveness.

$$f(V_n) \cong f(V_n)\Big|_{V_n=1^{Pu}} + \frac{df}{dV_n}\Big|_{V_n=1^{Pa}} .(V_n - 1^{Pu}) \\ \Rightarrow V_n^2 \cong 2V_n - 1 \tag{11}$$

$$p_{l,t,s}^{Send} = g_l(V_{n,t,s} - V_{m,t,s}) + \frac{1}{2}p_{l,t,s}^{loss} - b_l\phi_{n,t,s} + b_l\phi_{m,t,s} \tag{12a}$$

$$p_{l,t,s}^{Receive} = -g_l(V_{m,t,s} + V_{n,t,s}) + \frac{1}{2}p_{l,t,s}^{loss} - b_l\phi_{m,t,s} + b_l\phi_{n,t,s} \tag{12b}$$

$$q_{l,t,s}^{Send} = b_l(-V_{n,t,s} + V_{m,t,s}) + \frac{1}{2}q_{l,t,s}^{loss} - g_l\phi_{n,t,s} + b_l\phi_{m,t,s} \tag{12c}$$

$$q_{l,t,s}^{Receive} = b_l(V_{m,t,s} - V_{n,t,s}) - \frac{1}{2}q_{l,t,s}^{loss} + g_l\phi_{m,t,s} + g_l\phi_{n,t,s} \tag{12d}$$

$$p_{l,t,s}^{loss} = \frac{p_{l,t,s}^{Send^2} + q_{l,t,s}^{Send^2}}{V_{n,t,s}^2} r_l \tag{13a}$$

$$q_{l,t,s}^{loss} = \frac{p_{l,t,s}^{Send^2} + q_{l,t,s}^{Send^2}}{V_{n,t,s}^2} x_l \tag{13b}$$

4) *Capacity limits of lines*

The maximum and minimum power capacity of lines are assigned by (14a)-(14b).

$$p_{min}^{n,m} \le p_{t,s}^{n,m} \le p_{max}^{n,m} \tag{14a}$$

$$q_{min}^{n,m} \le q_{t,s}^{n,m} \le q_{max}^{n,m} \tag{14b}$$

5) *Operational constraints of dispatchable units*

The constraints of dispatchable units are listed as (15a)–(15f). The power generation of these units follows constraints (15a)–(15b). The commitment status of the generation units are demonstrated by the binary variable $I_{j,t}$. When the commitment status is set to zero in a specific time according to the operator's decision, the dispatchable units would be turned off and would not be committed during the hours. However, when the value is set to one in some hours, the unit would be committed to provide the required power for consumers. This binary value has no dependency to the scenarios, so the commitment decisions are made at the first stage of scheduling named here and now decisions. The unit's ramp up/down rate restrictions obey (15c)–(15d), which means that the units' power generation cannot be exceeded or reduced from the specific amounts, i.e., ramp up and ramp down, in two consecutive hours. Moreover, the limitation of minimum up/down hours are subjected to (15e)–(15f), which show the consecutive hours that the units would stay on and off, respectively. Because of the technical and economical restrictions, units cannot be turned on or off rapidly, so these constraints guarantee a realistic behavior for generation units [26].

$$P_{j}^{DU,min} I_{j,t} \leq P_{j,t,s}^{DU} \leq P_{j}^{DU,max} I_{j,t} \tag{15a}$$

$$Q_{j}^{DU,min} I_{j,t} \leq Q_{j,t,s}^{DU} \leq Q_{j}^{DU,max} I_{j,t} \tag{15b}$$

$$P_{j,t,s}^{DU} - P_{j,t-1,s}^{DU} \leq UR_{j} \tag{15c}$$

$$P_{j,t-1,s}^{DU} - P_{j,t,s}^{DU} \leq DR_{j} \tag{15d}$$

$$UT_{j}(I_{j,t} - I_{j,t-1}) \leq T_{j,t}^{on} \tag{15e}$$

$$DT_{j}(I_{j,t-1} - I_{j,t}) \leq T_{j,t}^{off} \tag{15f}$$

6) Operational constraints of ESS

Functional constraints of ESS are written in this part. The power capacity of ESS is acquired through (16a). The charging and discharging processes at time slots are confined by constraints (16b) and (16c) which are limited to the minimum and maximum power capacity in each process. The charging and discharging of ESS should not occur at the same time as enforced by (16d). The state of charge (SOC) in ESS is shown by (16e). This constraint represents the relation between the remained energy in charging/discharging procedure, efficiency of ESS and ESS power. It is evident that the remained or stored energy should be between the defined maximum and minimum ranges as (16f). Constraints (16g) and (16i) ensure the minimum number of consecutive hours that the ESS should keep its charging and discharging states [12].

$$P_{e,t,s}^{ESS} = P_{e,t,s}^{ESS,dch} - P_{e,t,s}^{ESS,ch} \tag{16a}$$

$$P_{e}^{dch,min} u_{t} \leq P_{e,t,s}^{ESS,dch} \leq P_{e}^{dch,max} u_{t} \tag{16b}$$

$$P_{e}^{ch,min} v_{t} \leq P_{e,t,s}^{ESS,ch} \leq P_{e}^{ch,max} v_{t} \tag{16c}$$

$$u_{t} + v_{t} \leq 1 \tag{16d}$$

$$SOC_{e,t,s} = SOC_{e,t-1,s} - (1/\eta) P_{e,t,s}^{ESS,dch} + \eta P_{e,t,s}^{ESS,ch} \tag{16e}$$

$$SOC_{e}^{min} \leq SOC_{e,t,s} \leq SOC_{e}^{max} \tag{16f}$$

$$MC_{e}\left(u_{t} - u_{t-1}\right) \leq T_{e,t}^{ch} \tag{16g}$$

$$MD_{e}\left(v_{t} - v_{t-1}\right) \leq T_{e,t}^{dch} \tag{16i}$$

7) Bus voltage regulation

Voltage of each bus is considered between 0.95 p.u and 1.05 p.u with the aim of constraint (17). The available resources like main grid power, generation units and responsive loads are responsible for satisfying this limitation.

$$0.95 \le V_{n,t,s} \le 1.05 \tag{17}$$

8) Load shedding limits

The inevitable curtailed load should be less than the actual load in each bus according to the constraints (18a)–(18b). Furthermore, the loads' power factor should also stay constant by (18c) after the load shedding.

$$0 \le P^{LS}_{n,t,s} \le P^{LS,max}_{n,t,s} \tag{18a}$$

$$0 \le Q^{LS}_{n,t,s} \le Q^{LS,max}_{n,t,s} \tag{18b}$$

$$P^{LS}_{n,t,s} = Q^{LS}_{n,t,s}\left(\frac{P^{Load}_{n,t,s}}{Q^{Load}_{n,t,s}}\right) \tag{18c}$$

9) Responsive load constraints

Using the Interruptible/Curtailable (I/C) program, the operator can send the incentive price signals to the responsive loads. After receiving these signals, responsive loads decide whether to participate or not in I/C DR program. The Industrial DR packages have price steps, and each step has a price due to the pre-determined contract. The responsiveness of the industrial loads are presented by constraints (19a)–(19d) [34]. L^b_ξ and L^b_{min} are the maximum and minimum consumption reductions in steps ξ and one, respectively. Also, at each time slot, the summation of the reduced demand should not be greater than L^b_ξ. Moreover, an assigned portion of the residential load is diminished, and its power reduction limitations in DR program are presented as (20a)–(20b) [26].

$$L^b_{min} \le l^b_1 \le L^b_1 \tag{19a}$$

$$0 \le l^b_\xi \le (L^b_{\xi+1} - L^b_\xi); \forall \xi = 2,3... \tag{19b}$$

$$IP^b_{n,t,s} = \sum_{\xi=1} l^b_\xi \tag{19c}$$

$$IC^b_{n,t,s} = \sum_{\xi=1} o^b_\xi l^b_\xi \tag{19d}$$

$$0 \le ReP_{n,t,s} \le ReP^{max}_{n,t,s} \tag{20a}$$

$$0 \le ReQ_{n,t,s} \le ReQ^{max}_{n,t,s} \tag{20b}$$

10) Risk constraints

It is commonly seen that the risk criteria have been used in the objective functions [15] and [35], but they can also be included as mathematical constraints in cost-benefit problems. In this study, constraints (21a)–(21d) are exercised to capture the adverse effects of the uncertainties on operation cost. Considering the mathematical viewpoint, CVaR is known as (21a), and the VaR dignifies to the least value of a group of expensive costs [30]. Constraint (21b) determines the risk preferences level within a adjusted β as a risk parameter which uses to ensure a compromise between the expected operation cost and risk aversion [36]. In fact, the value of this parameter is correlated to the operator's preference about the risk controlling strategy. A risk-averse person chooses a value close to one, while a risk-taker decision maker prefers a value larger than one before running the scheduling program [26].

$$\mathrm{CVaR} = \frac{1}{(1-\alpha)} \sum_{s=1}^{\Omega} \mathrm{prob}_s \eta_s + \mathrm{VaR} \tag{21a}$$

$$\frac{\mathrm{CVaR}}{\mathrm{EOC}} \leq \beta \tag{21b}$$

$$\begin{aligned} &\sum_{t=1}^{24} \{ c\Delta P_{t,s}^{+} + \rho_t^{AMG} P_{t,s}^{AMG} + \sum_{g\in G} F(P_{g,t,s}^{DU}) + \sum_{n\in N} P_{n,t,s}^{LS} \mathrm{VOLL}_n + \\ &\sum_{b\in B} IC_{n,t,s}^{b} + \sum_{n\in N} \mathrm{ReP}_{n,t,s} \Gamma_{t,s} \} - \mathrm{VaR} - \eta_s \leq 0 \end{aligned} \tag{21c}$$

$$\eta_s \geq 0 \tag{21d}$$

4 Case studies and results

4.1 Test system

The power management scheduling of DMG considering the interaction with AMG is applied to a test system (see Figure 4). Geographical constraints of AMG have not been considered in this test system as the scheduling problem will be solved from DMO operator’s perspective. It is supposed that AMG can provide a specific amount of power for DMG at bus 9 when the main grid is inaccessible. This is reasonable as the distribution systems’ feeders are geographically near together in some places, so this would be a good opportunity for MG operators to have interaction with each other. The line data of this system are taken from [26], and the technical specifications of the generation units are written in Table 2.

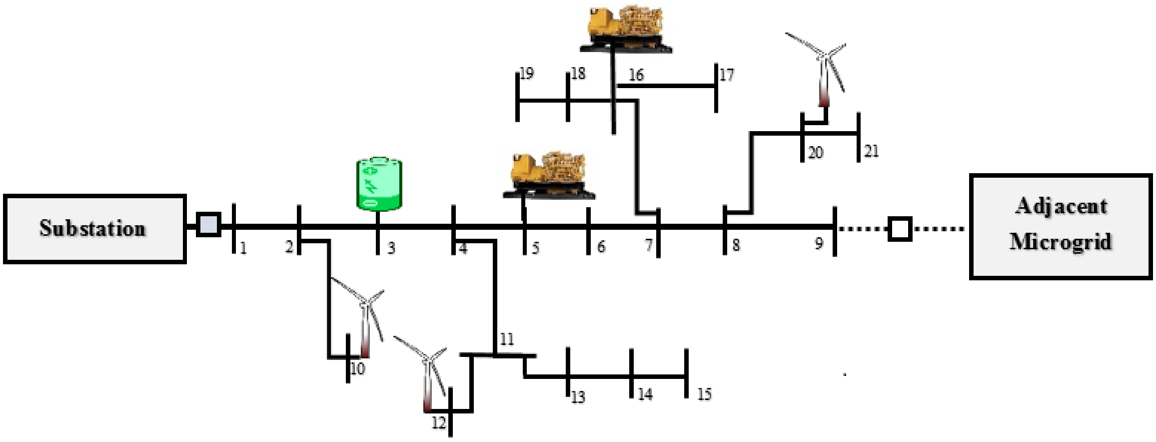

Fig. 4. Single line schematic of DMG

Table 2. Characteristics of ESS, dispatchable units, and the generation power of wind turbines

Dispatchable Units	BUS number	Operation Cost (€/MWh)	Min/Max Capacity (MW)	Min Up/ Down hours	Ramp Up/Down rate (MW/h)	Power factor
DU1	5	63	0.8-3	2	0.5	0.8
DU2	16	85	0.5-2	1	1.5	0.8
ESS	3	-	0.4-2	5	-	1
Wind turbines	10,12,20	-	0-3	-	-	1

Using SCENRED tool in the GAMS software for scenario generation and reduction, seven scenarios, each consisting of a vector of demand profile and wind turbines' output is attained.

Wind turbines with a total power capacity of 3 MW are deployed in three different areas. The output power generation of turbines is simulated according to the historical data of National Renewable Energy Laboratory (NREL) [37]. Since the buses where turbines are located are in small urban region, the speed of wind and as a result the power generation of turbines are the same. Figure 5 explicates the accumulated wind turbines generation in a 24-h horizon.

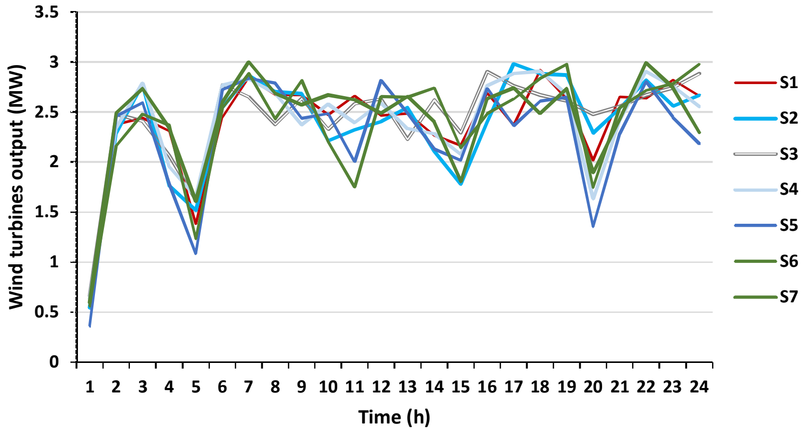

Fig. 5. Output generation power of wind turbines for different scenarios (S1 to S7)

Figure 6 illustrates the various scenarios related to the aggregated residential and industrial loads with 0.95 and 0.85 power factors, respectively. Industrial consumers with deterministic behavior are set at buses 10 and 21, but the residential consumers are distributed to other buses [26]. Residential consumption obeys a normal probability distribution function with a mean value equal to the forecasted data and a standard deviation of 25% [26].

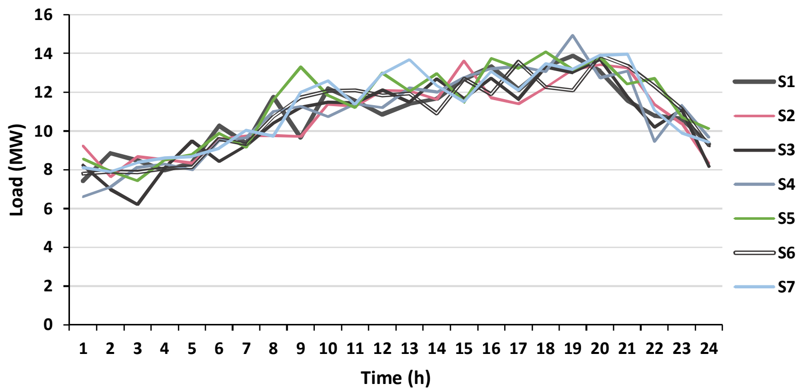

Fig. 6. Load profile for different scenarios (S1 to S7)

In this study, residential and industrial consumers are encouraged to take part in the DR program by receiving monetary advocates. The DR price-quantity package is indicated in Table 3 for industrial customers A and B which are located at buses 10 and 21, respectively. In each step of this package, the consumption of industrial loads can be diminished up to the maximum capacity represented in Table 3. DMG operator proposes incentives to the industrial loads according to the "price offers" indicated in the table for each step and these loads are encouraged to reduce their consumption in crucial hours. Similarly, residential loads can receive monetary incentives from DMG operator to reshape the consumption pattern. An hourly reduction cost of residential load between 7 am and 22 pm is tabulated in Table 4. It is assumed that 10% of the residential consumption is allowed to be reduced. The row of Table 4 named "expected reduction" dignifies the average reduction of consumption in all seven scenarios.

Table 3. Responsiveness price and power for industrial load

Industrial load A				
DR price-quantity steps	1	2	3	4
Maximum reducible power (MW)	0.10	0.20	0.20	0.10
Price offers (€/MWh)	160	230	320	470
Industrial load B				
DR price-quantity steps	1	2	3	-
Maximum reducible power (MW)	0.20	0.10	0.10	-
Price offers (€/MWh)	185	300	520	-

Table 4. Responsiveness price and power for residential load

Time (h)	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**
Expected reduction (MW)	1.90	2.14	2.21	2.32	2.28	2.38	2.41	2.44
Price signals (€/MWh)	92.90	93.60	93.81	94.12	94.50	95.30	98.50	98.91
Time (h)	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**
Expected reduction (MW)	2.46	2.56	2.53	2.62	2.66	2.65	2.49	2.19
Price signals (€/MWh)	99.61	100.22	101.62	113.46	114.89	115.71	115.93	115.65

Figure 7 demonstrates the assigned electrical energy package and its price at PCC bus with a deviation penalty of €70/MWh, which are determined by DMO [23].

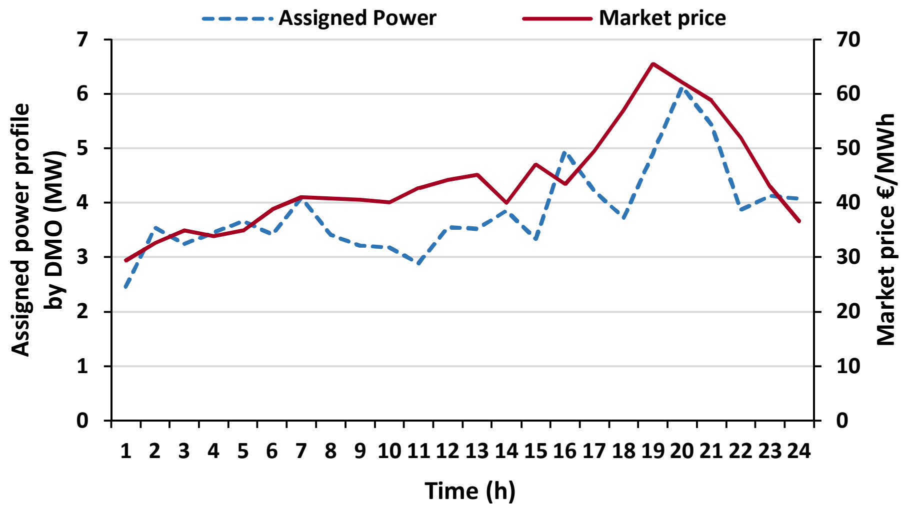

Fig. 7. Assigned power and price packages for DMG

In the following section, the power management scheduling of the DMG is solved by IBM CPLEX® Software [38] on a personal computer with 8GB RAM and 2.2 GHz processor considering min gap of 0%. Then, the numerical studies of DMG power management are explicated profoundly.

4.2 Numerical analysis

The market-based optimal power management for DMG is executed under two cases. First of all, this scheduling would be performed with a continuous access of DMG to the main grid. Then, this model would be further test considering islanded hours during the PM program.

4.2.1 Optimal power management considering main grid accessibility

Prior to executing the power management program, risk parameters α and β as well as flexibility limit (R) are adjusted to be 0.7, 1.05 and 2MW, respectively. The calculated expected operation cost of resources and CVaR are attained €7909.5 and €8305.1 in this case study. CVaR value denotes on the expected cost of expensive scenarios, and when the operator choose a value of β closer to 1, the cost of these costly scenarios would reduce because the risk averse strategy would try to minimize operation costs of costly or worst scenarios with the aim of installed resources. The significant portion of the operation cost is related to the dispatchable units, which is €7047.4, and the deviation penalty is also €862.1. The responsive loads have not participated in this scheduling as the power procured by main grid and local units is enough to supply the loads. It is worth mentioning that the operator deviate from the assigned power by DMO in order to supply its local load, so he should pay the penalty cost for that. Based on the flexibility limits, operator is not able to highly deviate from the assigned profile, which can satisfy the operational flexibility in distribution system [24]. Two important issues associated with the risk parameters and flexibility limit are scrutinized as follows:

a) Adjusting β

In Figure 8, it is shown that by increasing the amount of β to 1.1, the expected cost reduces to €7879 and the CVaR value increases to €8431 accordingly. In fact, when β gets closer to 1.1, the operation strategy changes to risk-taking mode, so the scheduling of resources would not perform based on the costly scenarios which CVaR reflects their feature. Consequently, the amount of CVaR increases according to this strategy. On the other hand, when β gets closer to 1, although the operation cost augments, the CVaR attains to €8229 which is €202 fewer than CVaR value in risk-taking scheduling. Considering these two amounts of β, it can be inferred that it would be better to make a tradeoff in scheduling by setting β between risk-averse and risk-taking policies. This would reduce the operation cost in comparison with risk-averse scheduling, and it also reduces the CVaR value regarding the risk-taking scheduling.

In addition, changing the value of this risk parameter means using the available resources of DMG in different mode as the policy of scheduling for each generation unit would change. Among the different resources, ESS is highly dependent to the risk preferences level. In fact, this unit has a specified and limited power capacity that should be discharged in the most crucial hours of operation. By way of illustration, Figure 9 shows the influence of setting β on charging and discharging of ESS. Choosing β=1 would control the charging and then discharging of the ESS to only mitigate the costly scenarios. However, in pure risk-taker strategy (i.e. β=1.1), the power capacity of the ESS is discharged in longer period of time (here 12 hours). In this regard, ESS discharge almost similar power capacity during the period of time to cope with the operational challenges of all scenarios regarding their probability of occurrences. This is why the expected charging/discharging pattern in risk averse policy (i.e. β=1) has more differences with the two other strategies. In another word, this risk averse scheduling policy just focuses on the worst scenarios and discharge the power in shorter period of time with a significant fluctuation in 12 and 19 pm to meet the power consumption in the related costly or worst scenarios.

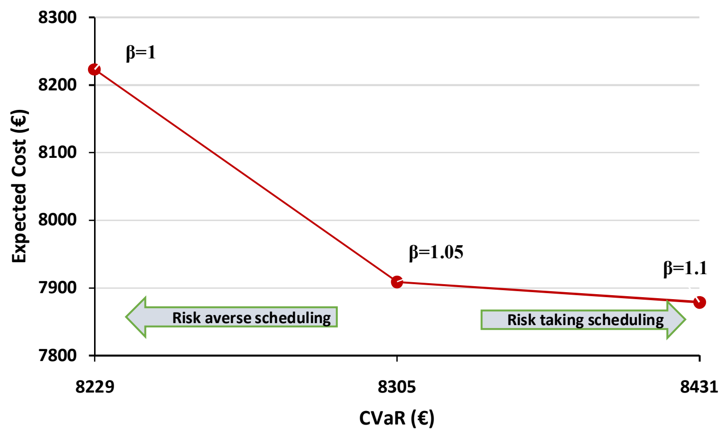

Fig. 8. Variation of CVaR and expected operation cost by setting β

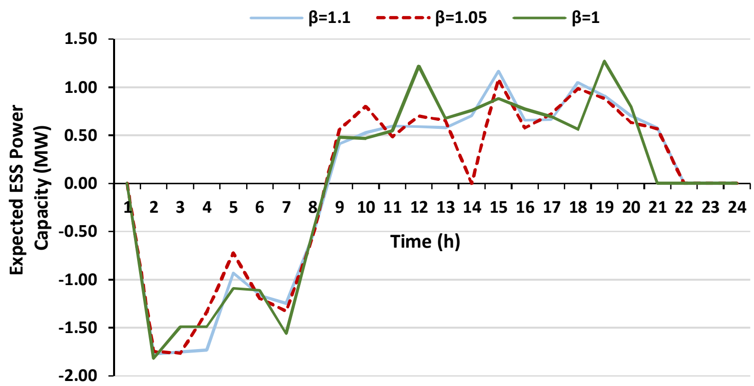

Fig. 9. Variation of expected ESS power by setting β

b) Considering R

The power deviation from the assigned power of DMO is highly depend on the load behavior, operation cost of generation units and wind turbine power, so when the local resources are not able to provide the power for loads or when providing power from the installed resources imposes further cost in comparison with buying additional power from the main grid, the operator would prefer to deviate from the assigned power profile and pay the penalty for buying the additional power. In some instances, the deviation may be intense, which can affect the operational flexibility [24]. In this situation, the upstream operator may see sharp fluctuations in power sent to the DMG. In order to show the effect of the flexibility limit on this power profile, Figure 10 is represented. Neglecting the flexibility limit imposes a power profile with intense fluctuation, but considering *R* smooths the power profile from the upstream grid viewpoint, which ensures flexibility in distribution system. It is to be noted that, this limitation which is determined by the DMO, would increase the operation cost because the DMG operator is obliged to rely on its local resources and use costly dispatchable units. In this study, operation cost in the presence of flexibility limit is 3.79% higher than the operation cost without considering flexibility limit. This additional cost should be paid to the DMG operator by DMO as this MG guarantees flexible operation for distribution grid.

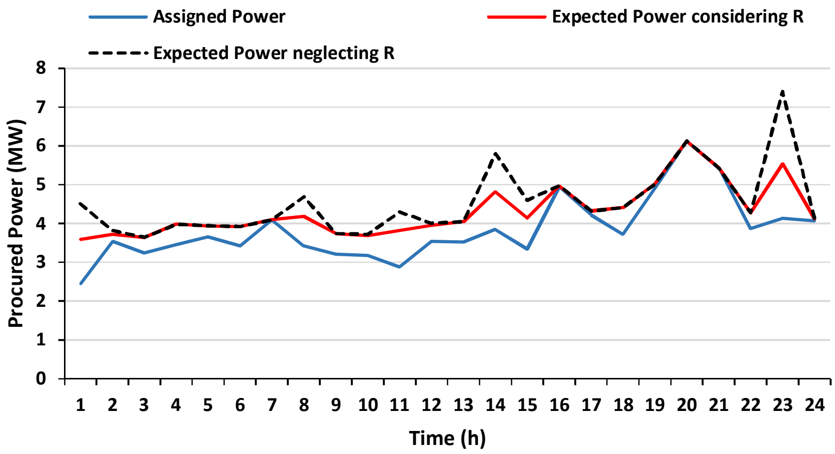

Fig. 10. Differences between assigned power profile and real-time expected power with respect to flexibility limit influences

c) Effect of uncertainties

In this section, a deterministic scheduling approach as our reference model is compared to the presented two-stage stochastic model in this paper. In deterministic approach the uncertainties associated with winds and loads are neglected, and just one predetermined scenario is considered during the scheduling horizon. After running the deterministic scheduling program, the operation cost attaints to €7721.3 with a cost breakdown of €6852.2 power generated from dispatchable units and €869.1 deviation penalty. Comparing this operation cost with the operation cost of the stochastic scheduling represented in this paper, it can be realized that the operation cost of stochastic model (i.e. €7909.1) is €187.7 higher. This is because in stochastic model, the operator considers various scenarios and commits generation resources in more hours to optimally schedule and manage any scenario that may happen. This additional participation of units will impose a little more operation cost, but it will be a safe and reliable operation if other probable scenarios happen. Table 5 shows that in stochastic operation, dipathcable units committed in more hours in comparison with deterministic operation tabulated in Table 6. The differences are highlighted in both tables. Additionally, ESS charging and especially discharging process cover a longer period of time to cope with the risk of uncertainties in any hours. However, as demonstrated in table 6, ESS charging and discharging program focuses on shorter period to meet the deterministic load and wind generation. This approach will impose a high load shedding cost if the load and wind generation units act different from the deterministic behavior, and it is absolutely possible during a day according to the forecast errors.

Table 5. Unit commitment status in stochastic approach: (1 and 0 means committed and not committed, respectively)

Gen. Unit	Commitment hours (1–24)																						
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
U1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
U2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0
ESS Charging	0	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESS discharging	0	0	0	0	0	0	0	0	1	1	1	1	1	0	1	1	1	1	1	1	1	0	0	0

Table 6. Unit commitment status in deterministic approach: (1 and 0 means committed and not committed, respectively)

Gen. Unit	Commitment hours (1–24)																						
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
U1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	1	1	1	1	1	1	1	1	1
U2	1	1	1	1	1	1	1	1	1	1	1	1	1	0	1	1	1	1	1	1	1	0	0	0
ESS Charging	0	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESS discharging	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	0	0	0	0

4.2.2 Optimal power management considering main grid inaccessibility

In this case study, the PM program which should be performed in upstream grid brings about islanding states of operation for DMG. It is assumed that the main feeder of the substation which the DMG is connected to should be disconnected for 5 hours in order to execute the PM work plan. The maintenance program starts from 15 pm, and finishes at 19 pm. Moreover, the AMG is also available to provide electrical energy up to 3MW during the PM program by selling its unused power capacity to the DMG with the price of €90/MWh.

Using the power management scheduling with the mentioned parameters, the operation cost becomes €9941.2 and calculating the CVaR value results in €10440.3. The operation cost increases 25.68% in comparison with the previous case study. This imposed cost is the consequence of islanding in which power generation units, responsive loads and unused capacity should be utilized more to supply the local loads and reduce the load shedding. Dispatchable units have significant portion in providing electrical power of consumers. The generation cost of these units is €7179.1, and it means that 72.21% of the power generation cost is associated with these resources. Since the operational costs of ESS and wind turbines are small in 24-h horizon, they have been neglected. Moreover, the cost of the load responsiveness and deviation are acquired €815.3 and €980.1. Responsive loads are implemented to reduce the load shedding. Beside these valuable flexible resources, AMG also provides remarkable amount of energy with the cost of €966.7.

For the sake of clarity, the worst scenarios' power scheduling is shown in Figure 11. Dispatchable units not only are committed significantly in hours before islanding, but also are participated in islanded hours with the full power capacity of 5MW. The ESS discharging profile depicts that 84.47% of ESS power capacity is allocated to islanded hours, and the charging process is planned between 2 am and 8 am during the off peaks. The AMG operator sells 11.58MWh to the DMG, which is a remarkable amount of energy when the main grid is inaccessible.

Another point to be mentioned is that power loss of DMG is insignificant as there are several installed power resources that can reduce the congestion of lines by supplying the adjacent loads, but during the islanded period the power loss would increase. As illustrated in Figure 11, the loss is increased %31.66 on average during the PM program in comparison to other hours. In fact, increasing the congestion of the lines due to the discharging of ESS and fully participation of dispatchable units in these hours, and conveying power flow to loads located in far regions of the DMG intensify the loss in the system.

Furthermore, the modified load is the result of load responsiveness, changing the pattern of the consumption in islanded hours to reduce costly load shedding with a VOLL of €1000/MWh and €3000/MWh for residential and industrial loads, respectively. The responsive loads reduce 8.8MWh of their consumption in islanded hours to guarantee the supply and demand balance.

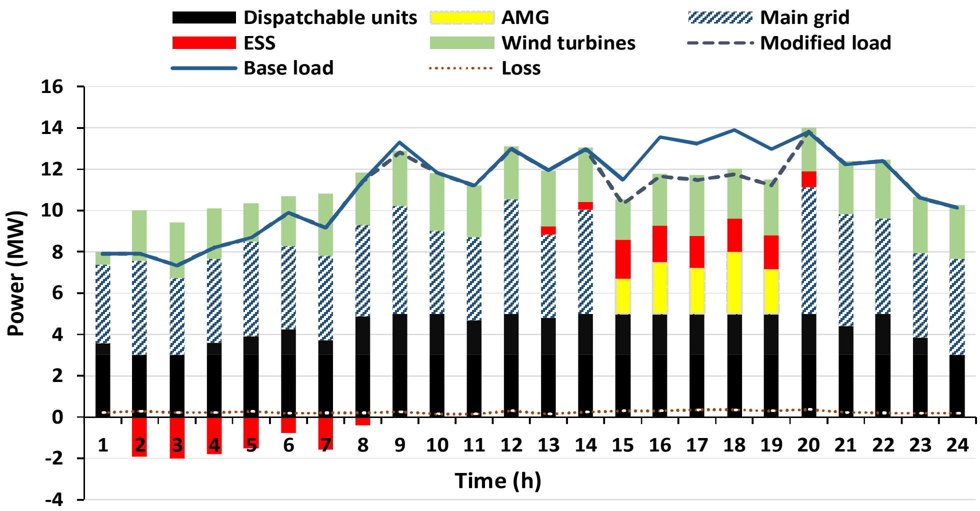

Fig. 11. Optimal power management of resources in worst scenario

In second case study, there are two factors that can be different from the presented assumption. The available unused capacity and islanding duration are the factors, which should be evaluated under different circumstances. The following analysis would delve into these factors during the scheduling:

a) *Available unused capacity*

The amount of the available power capacity may be fewer than the maximum power (i.e. 3MW) that can be received from AMG through the line between DMG and AMG. This may happen because of performing PM program in AMG as in DMG, generation deficiencies of RESs, critical peak loads and generation unit's failure. Therefore, it is assumed that the unused capacity of AMG is reduced to 50% of the specified capacity. The operator should reschedule the available resources to supply its load. As the maximum power capacity of the dispatchable units is utilized when the unused capacity is fully or even partially available in grid connected hours, the operator should rely on other resources during the islanded hours. Hence, he can deviate more from the assigned power profile in grid connected hours to store energy in ESS for islanded hours and also reshape the consumption profile through loads' responsiveness and load shedding. The operation cost rises to €10854.3, which contains of €1299.5 for the participation of responsive load and €697.3 for the load shedding. In this situation, the operation cost is 9.1% bigger than the case in which AMG could sell up to 3 MW power capacity to DMG. Figure 12 compares the consumption reduction of responsive loads when the unused capacity is 100% and 50% of the maximum unused capacity. These loads significantly compensate the shortages of AMG's power capacity. It is to be noted that the expected load shedding energy is 0.63MWh which is unavoidable with this limited access to the unused power capacity. Moreover, the deviation penalty and the purchased power from AMG are €1061.1 and €699.4, respectively. However, the operation cost of dispatchable units remains the same in comparison with the scheduling mode in which 100% of the unused capacity is available.

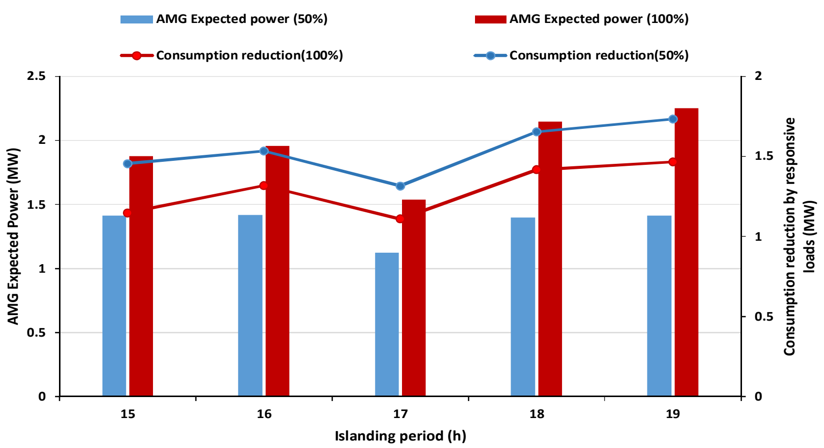

Fig. 12. Participation of AMG and responsive loads in islanded hours considering the 100% and 50% availability of unused power capacity

b) *Islanding duration*

The inaccessibility of the DMG to the upstream grid, which is relevant to the PM program may last longer period of time than the predicted time for performing the program. Therefore, it would be beneficial to evaluate different islanding periods which can change the scheduling of generation resources.

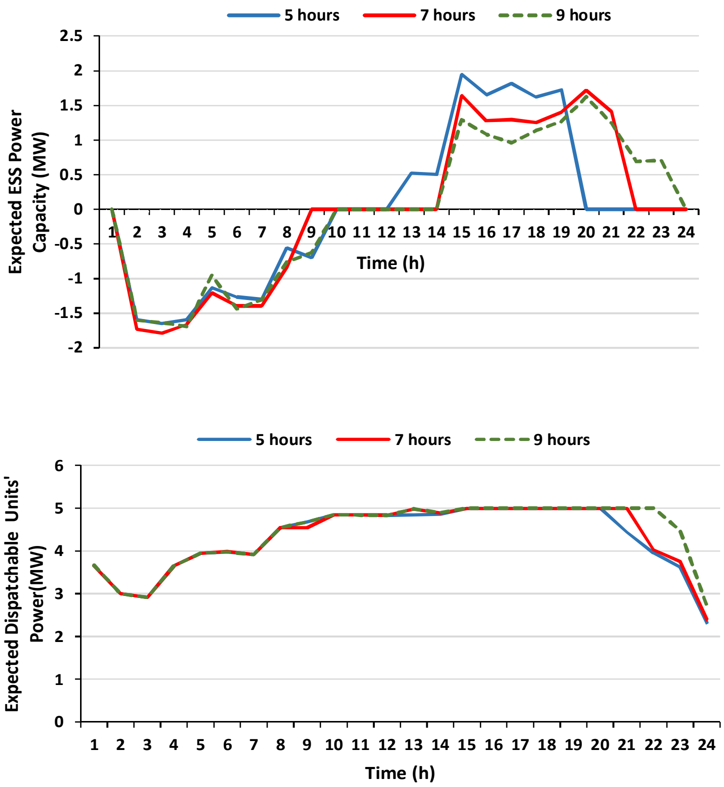

Fig. 13. (a) ESS expected power charging/discharging, and (b) Expected power generation of dispatchable units for different islanding periods

Figure 13.a depicts the discharging of limited ESS capacity in different islanded period. It is shown that the discharging process would perform in longer period of islanding time (i.e. 9 hours) to cover power shortages, while it will be restricted in shorter period if the islanding duration is set at shorter period of time (i.e. 5 hours). Therefore, increasing the islanding period would smooth discharging rate for ESS to supply loads in all islanded hours.

In addition, the dispatchable units would provide more generation power in longer islanded period to cope with the power shortages. Figure 13.b depicts the expected power provided by dispatchble units in three islanding circumstances.

Figure 14 shows the increment of operation cost related to 5, 7 and 9 consecutive islanding period. To be more specific, it is shown that just 10% improvement of load responsiveness results in 3.1% reduction of expected operation cost when 9 hours islanding occurs.

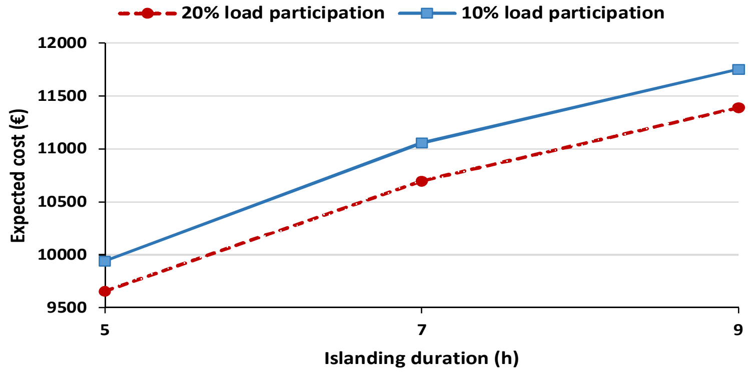

Fig. 14. Expected operation cost's trends considering two level of load responsiveness in different islanding periods

Table 7. Economic and computational time comparison between different case studies

Case studies		Unused capacity	Expected cost (€)	CVaR (€)	Deviation penalty (€)	Operation cost of dispatchable units (€)	DR participation cost (€)	VOLL (€)	AMG purchased cost (€)	Computational time (second)
Main grid accessibility		-	7909.5	8305.1	862.1	7047.4	0	0	-	87.5
Main grid inaccessibility		100%	9941.2	10440.3	980.1	7179.1	815.3	0	966.7	57.4
		50%	10854.3	11397.4	1061.1	7179.1	1217.4	697.3	699.4	41.2

For the sake of brevity, a detailed comparison containing economic aspects and computational time of the scheduling procedure for different case studies are presented in Table 7. As it was assumed, the risk parameter, islanding duration and flexibility limit are 1.05, 5 hours and 2 MW, respectively.

5 Conclusion

An optimal stochastic power management scheduling was suggested in this paper, which considered the risk constraints, flexibility limit, distribution market and linearized formulations of AC power flow in the mathematical model. The presented model was developed to economically model the day-ahead operation of DMG. This class of MG had almost the same features of other MGs and contained dispatchable units, responsive loads, wind turbines, and ESS. However, it was also able to purchased unused power capacity of AMG to supply its loads when the main grid bulk power capacity was not available as a result of performing

PM program in it. The uncertainties associated with the loads and wind power output were generated, and reduced by scenario reduction methods. The model utilized the generated power of installed resources and responsive loads for economic operation regarding the interactions with DMO and AMG's operator. A 21-bus test system was employed to evaluate the effectiveness of the presented model under different numerical studies, and the following conclusions were drawn:

- The operator could choose a value of β close to 1 for scheduling the resources according to the risk-averse policy; however, he was also able to set a value close to 1.1 to follow a risk-taking policy. The results clarified that choosing a value between them (e.g. 1.05) could satisfy operational economic and mitigate the worst scenario's consequences.
- Adjusting the risk parameter (β) rescheduled the generation resources to satisfy risk-averse or risk-taker policies. ESS charging/discharging profile had more differences in risk-averse policy in comparison with other strategies because the optimal charging/discharging scheduling for just worst scenarios was important in risk-averse scheduling.
- It was shown that considering DMO reduced the imposed uncertainties, and facilitated the decision making problem for DMG operation.
- The distribution market constraints could reduce sharp changes of power procured from the upstream with the aim of flexibility limit. It was discussed that the market constraints ensure operational flexibility and reduce peak load in power system.
- Implementing DMG in distribution system was economically beneficial in islanded hours as the unused power capacity of AMG was purchased through additional interconnection point of DMG, which reduced the load shedding and operation costs.
- Several sensitivity analysis related to the AMG available unused capacity and islanding duration were performed to test the accuracy of the presented model. The responsive loads and ESS remarkably compensate the power shortages caused by longer islanding duration and energy deficiencies of AMG.

In general, market-based power management scheduling with relying on the unused power capacity would reduce the underutilization of the installed dispatchable units, diminish the power fluctuation in power system, enhance operational flexibility, remove the need for installing dispatchable units in future and guarantee the reliability as well as economic operation. This study could be further extended to concentrate on both DMO and DMG perspective in order to find the market price at PCC bus and determine the optimum flexibility limit.

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