Cost-aware Flexibility Evaluation for Microgrids

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***Abstract*—As the penetration of intermittent renewable energy resources in microgrids (MGs) continues to grow globally, optimal operation management becomes increasingly crucial due to the variability of these sources. One potential solution to this challenge is the use of demand response (DR) programs, which are practical and relatively low-cost options. However, ensuring the security of MG operation also requires evaluating its flexibility by determining the acceptable boundaries of uncertain variables. Additionally, in real-world operational decision-making problems, there is a simultaneous optimization of multiple objectives, including the maximization of system flexibility and the minimization of system cost. This paper presents a methodology for developing a cost-aware flexibility evaluation method for MGs connected to the upstream grid, which are subject to volatile market prices. The model is based on the feasibility analysis of the uncertain space of wind power generation and load, and it also investigates the level of inflexibility present in the system. The impact of the DR program on the flexibility of MGs is quantified through a case study. The case study confirms the success of the proposed method and underscores the significance of cost modeling in flexibility evaluation problems.**

***Index Terms*—Flexibility, demand response, microgrid management, uncertainty.**

I. Introduction

POWER systems all over the world are passing through a fundamental transformation led by a shift from utilizing fossil fuel to variable renewable energy resources. A discrepancy between demand and generation arises with the flow of these fluctuating energies into the power systems as well as the uncertainty of electric load. Thus, more flexibility is indispensable to alleviate discrepancies between supply and demand [1], [2]. Flexibility is one of the highly crucial application indices of present and future power systems as a supplement to the reliability, security, and economy concepts [3].

Flexibility evaluation is crucial in analyzing modern power systems, essential for effectively navigating uncertainties and operational challenges. This evaluation focuses on defining and quantifying flexibility to support informed decision-making in system operation and planning.

Based on foundational research, as exemplified by [4], operational flexibility is conceptualized as the capacity of the grid to manage uncertainties through the strategic deployment of controllable assets, while maintaining power balance over a period of time. This basic definition forms the cornerstone for further discussions on flexibility evaluation. Building on this concept, [5] introduces a probabilistic indicator to measure flexibility, acknowledging the inherent uncertainties within power systems. This method offers insights into how the system responds to short-term uncertainties in the context of long-term planning.

Various methodologies contribute to flexibility evaluation. For instance, [6] proposes an interval-based approach to assessing supply and demand flexibility. It also presents a methodology for evaluating the flexibility of diverse resources such as fast-ramping units, energy storage, and demand response (DR), within the day-ahead scheduling model. Additionally, methods like the inter-temporal model [7], Monte Carlo simulation [8], and optimization techniques [9] are crucial for evaluating flexibility across different timeframes and operational scenarios. In addition, [10] presents an envelope-based method to evaluate energy resource flexibility, particularly pertinent within the domain of economic dispatch and unit commitment. This methodology is complemented by [11], which examines flexibility dynamics through a theoretical framework, encompassing factors such as system reliability and operation costs.

The presented methods for the flexibility evaluation have manifested the power system capability to deal with different standpoint uncertainties. These methods have noticeable differences in characteristics of application scenarios and evaluation indicators. Regarding the application scenarios, the flexible indicators primarily emphasize transmission system analysis. The research on flexibility quantification with a focus on microgrids (MGs) that are connected to the upstream grid and have a high penetration of intermittent renewable energy resources is yet in the initial phase and there are only a few studies on it. Emerging studies like [12]-[14] aim to develop tailored methods for MG flexibility evaluation. A region-based mathematical formulation of operational flexibility for MGs is presented in [12], encompassing con-

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cepts such as flexibility provision and availability to represent the adjustable regulating capacity of MGs. Evaluating the acceptable and possible borders of distributed power generation uncertainties is crucial for ensuring MG operation security, as demonstrated in [13]. Reference [13] introduces a set-based method to formulate the acceptable boundaries of distributed generation uncertainties, along with operation restrictions of MGs as security sets of polytopes. Moreover, research in another field [14] presents a flexibility analysis method based on a direction matrix that describes the deviation direction of uncertain parameters. The multidimensional region of uncertain parameters has been modeled in [14] using hyperrectangle adaptation. It is vital to emphasize that methodologies discussed in [12]-[14] overlook crucial factors such as the operation cost of the system in the proposed flexibility metric. Therefore, a comprehensive understanding of flexibility evaluation requires considering both technical and economic aspects.

In summary, the quantification of MGs' flexibility, involving the evaluation of uncertain parameters alongside the consideration of operation costs and technical constraints of network elements, remains largely unexplored in current literature. Addressing this gap, this paper proposes a cost-aware flexibility evaluation method based upon the coverage of the feasible space to the uncertain space.

Currently, utilities are exploiting the flexibility of available resources such as energy storage systems and DR programs to improve or ensure the security of networks [15], [16]. In [17], it has shown that the flexibility of the DR program can attain greater financial benefits in the long term than energy storage systems considering the Great Britain market situation. The DR program can be employed to smooth out the intermittency of the load curve and improve the effectiveness of both the demand and supply sides [18], [19]. Furthermore, the DR program can decrease the variation of net load and as a result, propagate the incorporation of renewable energy resources in MGs [20]. DR programs are characterized into two key groups as price-based and incentive-based programs [21]. The price-based programs can be categorized into real-time pricing, critical peak pricing, and time-of-use (TOU) programs [22]. While, the incentive-based programs contain demand bidding/buyback programs, direct load control, emergency DR, capacity market, and ancillary service market [23]. With ever-increasing use of the DR programs in networks, investigating the impacts of TOU programs on distribution network scheduling along with the operation costs and flexibility is gaining more and more importance. The operational flexibility of the DR-equipped MG is quantified in [24] by using three evaluation indexes, i.e., renewable energy resource utilization, voltage deviation, and relative risk reduction. However, the effect of the DR program on flexibility in terms of feasibility evaluation of uncertain parameters has not been investigated in the literature. Thus, the TOU-based DR (TOU-DR) program is employed in the paper to improve the MG flexibility and the value of this improvement is quantified.

In this paper, the flexibility and inflexibility evaluation method is proposed considering the MG operation cost. The proposed method is based upon the feasibility evaluation of uncertain spaces of load and wind power generation. The projection of each direction in the uncertain space to the feasible space is illustrated and scrutinized. In addition, the question of how to model the MG operation cost impact on the flexibility evaluation is addressed. The impact of the operation cost and most constraints of MG on the flexibility evaluation is modeled and investigated. The impact of the TOU-DR program on the flexibility index has been quantified and analyzed. To sum up, the significant benefits of the proposed contribution are as follows:

1) Our method for flexibility evaluation conducts a thorough analysis of variable loads and wind power within uncertain spaces. It tackles the fundamental questions of where, when, and why inflexibility arises, shedding crucial light on its underlying causes and conditions. Moreover, this study assesses both the flexibility and inflexibility of MGs in scenarios where they connect to the main grid and contend with day-ahead market prices.

2) This study delves deeper into understanding the impact of diverse uncertain inputs, perceived as inconsistent from the MG operator's viewpoint, on the methodology used to quantify flexibility. The method integrates the MG operation costs into the flexibility evaluation process. Additionally, it scrutinizes the economic aspects of the TOU-DR program in providing flexibility to MGs.

3) The mapping of each direction vector within the domain of uncertainty onto the domain of feasibility is analyzed and studied. The visualized mapping onto the domain of feasibility can aid in identifying the cause of inflexibility.

4) To accurately reflect real-world conditions, a linearized representation of AC power flow constraints is employed. Additionally, the computation of the flexibility index is formulated as a linear and convex mathematical optimization problem that can be efficiently resolved using non-commercial solvers, ensuring optimal solutions.

The rest of the paper is structured as follows. Section II presents the definition of the MG flexibility concept and the mathematical formulation and framework of the proposed cost-aware flexibility evaluation method. Section III addresses the formulation of MG scheduling problem, detailing the constraints of the proposed model. Section IV discusses the numerical results from simulations, and Section V concludes the paper.

II. Definition of MG Flexibility and Mathematical Formulation and Framework of Proposed Cost-aware Flexibility Evaluation Method

As it was mentioned, the research on the MG flexibility evaluation, specifically considering the uncertain space and cost-effectiveness, is still in the initial phase and requires more attention. In this regard, first, the interpretation of the MG flexibility is defined, and next, the mathematical formulation and framework of the proposed cost-aware flexibility evaluation method are outlined.

A. Definition of MG Flexibility

From the viewpoint of this paper, the MG flexibility is the capability of the MG to maintain the power balance of the network and cope with complicated uncertainties cost-effectively and continuously, by the deployment of numerous controllable assets. In this framework, the flexibility quantification for renewable energy integrated MGs is defined as evaluating the MG compliance to uncertain parameters, which are wind power generation and load prediction errors. Furthermore, the calculation of the MG flexibility is based upon the feasibility evaluation in the space of uncertain variables considering the cost function. In the feasible operation space of the MG, all of the operation set points are disintegrated into the direction trajectory and the deviance scalar that is conveyed by a direction matrix. Finally, the most critical spot in the feasible space is recognized as a measure for MG flexibility.

B. Mathematical Formulation of Proposed Method

In this paper, the numerical criterion specification for the flexibility analysis in the MG is accomplished by employing the flexibility index. The mathematical formulation of the proposed method for the flexibility analysis is presented below.

$$FI = \min_{j} \boldsymbol{\delta}^{D_j} \tag{1}$$

$$\boldsymbol{\delta}^{D_j} = \max_{\boldsymbol{x}} \boldsymbol{\delta} \tag{2}$$

s.t.

$$h_i(\boldsymbol{c}, \boldsymbol{x}, \boldsymbol{z}) \leq 0 \quad i \in I \tag{3}$$

$$\boldsymbol{z} = \tilde{\boldsymbol{z}} + \boldsymbol{\delta}^{D_j} .* \Delta \boldsymbol{z} \tag{4}$$

where FI is the value of the flexibility index, with a non-negative scaled deviation $\boldsymbol{\delta}$ in direction D_j; h_i is the i^{th} element of $\boldsymbol{h}$, and $\boldsymbol{h}$ is the vector of equations, indicating all the constraints in the MG that have to be fulfilled in the feasible space; $\boldsymbol{c}$, $\boldsymbol{x}$, and $\boldsymbol{z}$ are the vectors of design variables, control variables, and uncertain parameters, respectively; I is the total number of elements; $\tilde{\boldsymbol{z}}$ is the forecasted value of the uncertain parameter; $\Delta \boldsymbol{z}$ is the difference between the forecasted value of the uncertain parameter and its maximum deviation; and .* is the Hadamard product, which represents the multiplication of two matrices. The flexibility index is characterized as the minimum scaled deviation $\boldsymbol{\delta}^{D_j}$ of the expected deviations in the feasible operation space. In other words, the objective of (1) is to find the critical direction in the uncertain space. Furthermore, the level of inflexibility, denoted as IFI, is defined as $IFI = 1 - FI$. Any operation point in the feasible space can be formulated by (4). Considering a specific direction in the feasible operation space and a specific time interval, the dimension of $\boldsymbol{\delta}^{D_j}$ and $\boldsymbol{\delta}$ is 1×1.

1) Description of Feasible and Uncertain Spaces

In this part, the details of the proposed method are described. The concept of the proposed method with respect to the 2D uncertain and feasible spaces is illustrated in Fig. 1, where Z_w and Z_l are the uncertain parameters of the wind power generation and load, respectively; $\tilde{Z}_w$ and $\tilde{Z}_l$ are the expected values of the uncertain parameters; $z_w^{\min}$ and $z_w^{\max}$ are the minmum and maximum values of Z_w, respectively; and $z_l^{\min}$ and $z_l^{\max}$ are the minmum and maximum values of Z_l, respectively. Suppose that the MG operates based on the expected values of the uncertain parameters (point O). According to the predictions, a reliable margin of uncertain parameters can be determined, which leads to the uncertain space. This area is limited to the minimum and maximum values of the uncertain parameters and plotted for the two uncertain parameters in Fig. 1. Regarding different directions from point O, and mapping different operation points of each direction to the coordinate system, feasible space can be achieved. The boundary of this feasible space specifies the maximum feasible deviation at direction D and is indicated by $\boldsymbol{\delta}^D$ ((2)). Any point inside the boundary implies a feasible operation scheme that satisfies all technical and economical constraints. However, on the points outside the feasible space, the system operation will be infeasible either technically or economically. The direction with the minimum feasible deviation in the uncertain space is the critical direction and its corresponding boundary point stands the critical point (i.e., point B in Fig. 1). The value of $\boldsymbol{\delta}^D$ in the critical direction is the flexibility index FI ((1)). Therefore, an appropriate criterion for the flexibility can be obtained by analyzing the boundary of the feasible and uncertain spaces. It should be noted that by extending the uncertain parameters to n parameters, the uncertain space will be an n-dimensional hyper-rectangle.

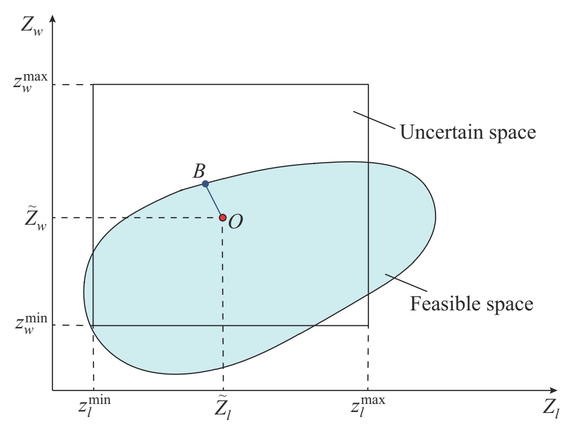

Fig. 1. 2D uncertain and feasible spaces.

2) Direction Matrix

In order to allude the direction in the hyper-rectangle, the direction matrix $\boldsymbol{D}$, which is a diagonal matrix, is defined as [25]:

$$\boldsymbol{D} = \begin{bmatrix} d_1 & & & \\ & d_2 & & \\ & & \ddots & \\ & & & d_n \end{bmatrix} \tag{5}$$

where d_i is the direction of the i^{th} uncertain parameter; and n is the number of uncertain parameters. The values of d_i are arbitrary numbers in the range of −1 and 1 to represent all possible directions.

3) Cost Modeling

In this paper, flexibility is regarded as the ability to balance energy demand and supply cost effectively [26], while simultaneously preserving acceptable service quality to connected loads. Therefore, one of the most important factors that should be considered along with the flexibility improvement is being cost-effective. To achieve this end, the effect of different factors on the cost function and flexibility index should be determined. In the proposed method, the uncertain parameters are wind power generation and load [27]. Both of these parameters are somewhat contradictory to each other from the point of view of the MG operator. In other words, an increase in wind power generation is tantamount to a reduction in electricity consumption. Therefore, for each direction in the uncertainty space, a different consequence on the cost function is expected. Figure 2 illustrates the status of both the cost and maximum feasible deviation in different directions, where ΔZ_w and ΔZ_l are the differences between the forecasted value of the wind power generation and load and their maximum deviations, respectively; $\Delta z_w^{\min}$ and $\Delta z_w^{\max}$ are the minimum and maximum variations of wind power generation, respectively; and $\Delta z_l^{\min}$ and $\Delta z_l^{\max}$ are the minimum and maximum variations of the load, respectively. The pink and blue regions denote the conflict and non-conflict regions, respectively. The effect of wind power generation and load variations should be scrutinized on the status of these functions in terms of having conflict or non-conflict.

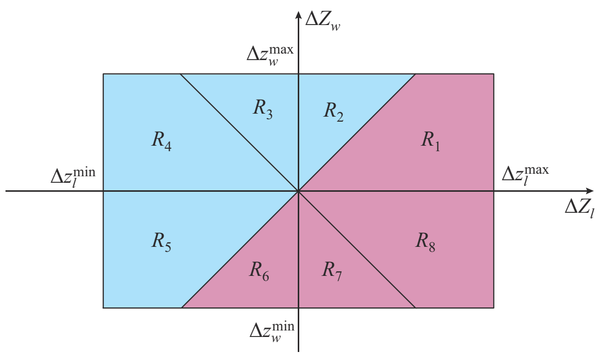

Fig. 2. Uncertain parameter variation and its association with cost.

As is obvious from Fig. 2, the two functions, i.e., cost and maximum feasible deviation, have different behaviors in different areas. Each point in the coordinate system is equivalent to a combination of uncertain parameter variation $(\Delta Z_l, \Delta Z_w)$. Any variation in the wind power generation and load will be in a certain direction, and each direction, depending on its area, determines the status of these two functions. Based on the aforementioned points, the effects of wind power generation and load variations conflict with each other, so the amount of each variation is important in determining the effect of the sum of these two variations. In order to handle the challenge, bisectors of quadrants are employed to analyze the status of functions.

In areas where the cost and maximum feasible deviation increase or decrease simultaneously due to variations in wind power generation and load, the two functions will be non-conflicting; otherwise, they will conflict. For instance, in zone R_2, the value of ΔZ_w is larger than that of ΔZ_l. Therefore, the overall variation (increasing both Z_w and Z_l) is equivalent to the positive variation in generation, resulting in a decrease in cost in this area. Consequently, maximizing the feasible deviation and limiting the cost value will not be conflicting. Table I provides the statuses of these two functions. Due to the variability of the statuses of these two functions in different areas, the cost function is treated as a constraint in the flexibility evaluation.

TABLE I
COST AND MAXIMUM FEASIBLE DEVIATION STATUSES IN DIFFERENT ZONES

Zone	Total uncertain parameter variation $\Delta Z_l - \Delta Z_w$	Cost variation	Cost and maximum feasible deviation status
R_1	Positive	Increased	Conflict
R_2	Negative	Decreased	Non-conflict
R_3	Negative	Decreased	Non-conflict
R_4	Negative	Decreased	Non-conflict
R_5	Negative	Decreased	Non-conflict
R_6	Positive	Increased	Conflict
R_7	Positive	Increased	Conflict
R_8	Positive	Increased	Conflict

C. Framework of Proposed Method

The flowchart of the proposed method for evaluating flexibility and improving the flexibility index is illustrated in Fig. 3. It is noteworthy that our method is applicable in real-world scenarios. As depicted in this figure, the proposed method encompasses three primary functions.

Step 1: the optimal operation of renewable energy resources as well as interactions with the wholesale market is obtained. The main aim of the optimal operation of the MG is minimizing the total operation cost *OPC* considering technical operation constraints that are being presented as $\boldsymbol{h}(\boldsymbol{c},\boldsymbol{x},\tilde{\boldsymbol{z}}) \leq \boldsymbol{0}$. Decision variables $\boldsymbol{x}$ contain the energy exchange with the main grid, status and power output of renewable energy resources, power flows in the lines, voltage magnitude and phase at the buses, etc. C^{ADN} is the cost function whose value is the minimum feasible operation cost.

Step 2: the nature of volatility in uncertain parameters necessitates envisaging all possible scenarios regarding changes from the expected values of these parameters. Therefore, the maximum feasible deviation is obtained in each direction and accordingly, the feasible operation space of the MG considering the uncertain space and technical constraints is determined in the "evaluating feasible operation space" module. To envisage economic aspects in determining feasible operation space, a constraint corresponding to the operation cost is incorporated in this module. So, the operation cost in each direction should be less than $(1+\alpha)C^{ADN}$, where α is the cost increment coefficient.

Step 3: the minimum value of the maximum feasible deviations from the expected value of uncertain parameters in all directions concerning the uncertain space denotes the flexibility index.

Step 4: the obtained flexibility index for the interval t is compared with a threshold value FI^{th}. Here, k denotes the discrete time step in the simulation. In the case that FI is less than FI^{th}, the considered cost increment coefficient α should be increased in a stepwise manner, i.e., $\alpha = \alpha + \beta$ (β is the step size), and the flexibility quantification process returns to *Step 2*. This mechanism is iterated to achieve FI^{th} and at each iteration it, the cost increment coefficient is equal to $\beta \cdot it$. It should be mentioned that the operator with the higher economic priority selects lower values for β and FI^{th} and the operator with the higher flexibility priority uses higher values for β and FI^{th}.

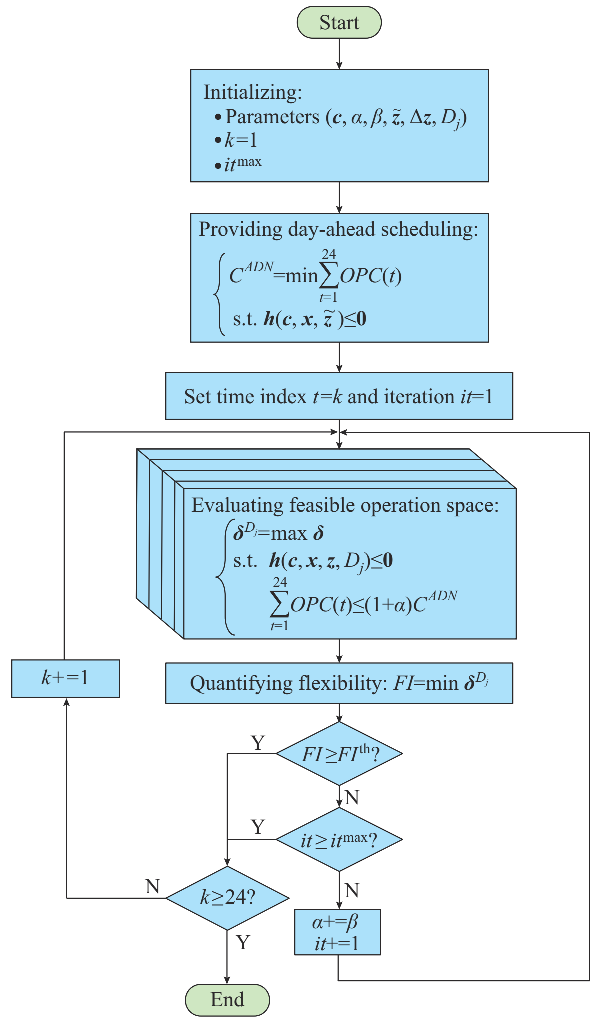

Fig. 3. Flowchart of proposed cost-aware flexibility evaluation mothod.

III. Formulation of MG Scheduling Problem

The operation of renewable energy integrated MGs requires to be effectively managed to minimize the power preparation cost and then the flexibility index will be evaluated. The MG is supposed to be equipped with conventional generation units and wind turbines. In addition, the MG operator can supply the demand using the day-ahead market. The major sources of uncertainty are wind power generation and load. It should be mentioned that this study primarily addresses the operational aspects of the MG within the 24-hour horizon.

A. Cost Function

The cost of the MG contains the operation cost of its facilities and the cost of buying energy from the day-ahead market. Its revenue is derived from selling surplus energy to the market. Hence, the cost function is given as:

$$C^{MG} = \min_{\psi} \left\{ \sum_{t=1}^{N_T} \lambda_t^{DA} P_t^{grid} + \sum_{i=1}^{N_{Gen}} C(P_{i,t}^{Gen}) \right\} \tag{6}$$

$$C(P_{i,t}^{Gen}) = a_i P_{i,t}^{Gen} \tag{7}$$

where Ψ is the decision variable being minimized in the problem; N_T is the total number of time steps in the scheduling horizon; N_{Gen} is the total number of generators; λ_t^{DA} and P_t^{grid} are the day-ahead market price and the power purchased from the market, respectively; $C(P_{i,t}^{Gen})$ is the operation cost of generation units; $P_{i,t}^{Gen}$ is the power generation of generation unit i; and a_i is the cost coefficient of generation units.

B. Power Flow Equations

In the proposed method, a linearized form of AC power flow restrictions [28] is utilized to build the real-life situation. According to Kirchoff's laws, the linearized formulation of active power and reactive power injections at bus b are given as:

$$P_{b,t}^{inj} = (2V_{b,t} - 1)G_{bb'} + \sum_{b(b \neq b')=1}^{N_{bus}} [G_{bb'}(V_{b,t} + V_{b',t} - 1) + B_{bb'}(\delta_{b,t} - \delta_{b',t})] \tag{8}$$

$$Q_{b,t}^{inj} = (1 - 2V_{b,t})B_{bb'} + \sum_{b(b \neq b')=1}^{N_{bus}} [G_{bb'}(\delta_{b,t} - \delta_{b',t}) - B_{bb'}(V_{b,t} + V_{b',t} - 1)] \tag{9}$$

where $V_{b,t}$ and $\delta_{b,t}$ are the voltage amplitude and phase angle of bus b, respectively; N_{bus} is the total number of buses; and $G_{bb'}$ and $B_{bb'}$ are the real and imaginary components of MG admittance matrix, respectively. The transferred active power $PL_{bb',t}$, reactive power $QL_{bb',t}$, and apparent power $SL_{bb',t}$ via the line bb' are given in (10)-(12), respectively.

$$PL_{bb',t} = -G_{bb'}(V_{b,t} - V_{b',t}) + B_{bb'}(\delta_{b,t} - \delta_{b',t}) \tag{10}$$

$$QL_{bb',t} = B_{bb'}(V_{b,t} - V_{b',t}) + G_{bb'}(\delta_{b,t} - \delta_{b',t}) \tag{11}$$

$$SL_{bb',t} = PL_{bb',t} + \Upsilon_{bb'} \cdot QL_{bb',t} \tag{12}$$

where $\Upsilon_{bb'}$ depends upon the load power factor, and this auxiliary parameter is computed in [29]. Equations (13) and (14) are used to calculate the total active and reactive power injections at bus b, respectively.

$$P_{b,t}^{inj} = \sum_{i \in \phi} P_{i,t}^{Gen} + \sum_{\omega \in \phi} P_{\omega,t}^{Wind} + P_t^{grid} - P_{b,t}^{L} \tag{13}$$

$$Q_{b,t}^{inj} = \sum_{i \in \phi} Q_{i,t}^{Gen} + Q_t^{grid} - Q_{b,t}^{L} \tag{14}$$

where ϕ is the set of production facilities at bus b; $P_{\omega,t}^{Wind}$ is the wind power generation; $P_{b,t}^{L}$ and $Q_{b,t}^{L}$ are the active and reactive loads, respectively; $Q_{i,t}^{Gen}$ is the reactive power generation; and Q_t^{grid} is the reactive power injected from the grid. P_t^{grid} and Q_t^{grid} will take non-zero values if the equations are solved for the bus connected to the upper grid. Otherwise, they will be zero. The system technical constraints are expressed in (15)-(18). The MG bus voltage magnitude and phase angle are limited by (15) and (16), respectively. The power exchange with the main grid and the flowing apparent power through each branch must be in a restricted bound for a stable operation, as indicated in (17) and (18).

$$\underline{V} \leq V_{b,t} \leq \bar{V} \tag{15}$$

$$\underline{\delta} \leq \delta_{b,t} \leq \bar{\delta} \tag{16}$$

$$0 \leq P_t^{grid} \leq \bar{P}_t^{grid} \tag{17}$$

$$-\overline{SL}_{bb',t} \leq SL_{bb',t} \leq \overline{SL}_{bb',t} \tag{18}$$

where $\underline{V}$ and $\bar{V}$ are the lower and upper limits of $V_{b,t}$, respectively; $\underline{\delta}$ and $\bar{\delta}$ are the lower and upper limits of $\delta_{b,t}$, respectively; $\bar{P}_t^{grid}$ is the upper limit of P_t^{grid}; and $\overline{SL}_{bb',t}$ is the upper limit of $SL_{bb',t}$.

Equations (19)-(21) present the constraints of generation units. Equation (19) sets the power generation limits. Equations (20) and (21) set the ramp-up and ramp-down limits of generation unit i, respectively.

$$\underline{P}_i^{Gen} V_{i,t} \leq P_{i,t}^{Gen} \leq \bar{P}_i^{Gen} V_{i,t} \tag{19}$$

$$P_{i,t+1}^{Gen} - P_{i,t}^{Gen} \leq R_i^{up} \tag{20}$$

$$P_{i,t}^{Gen} - P_{i,t+1}^{Gen} \leq R_i^{down} \tag{21}$$

where $\underline{P}_i^{Gen}$ and $\bar{P}_i^{Gen}$ are the lower and upper limits of $P_{i,t}^{Gen}$, respectively; $V_{i,t}$ is the voltage amplitude of generation unit i; and R_i^{up} and R_i^{down} are the ramp-up and ramp-down limits of generation unit i, respectively.

C. DR Program

The DR is a useful and relatively low-cost solution for the optimal operation management and flexibility improvement of renewable energy integrated MGs. The TOU-DR program can encourage consumers to cope with their consumption regarding the received price signal. The consumers will decrease their consumption in the high-price time intervals or transfer it to the low-price time intervals. Price elasticity is the most practical way in the DR developing and can characterize the preference and behavior of consumers. In [30], a comprehensive model for DR has been driven based upon load specifications comprising price elasticity and demand profile. In this paper, it is assumed that MG consumers are pretty inclined to participate in the TOU-DR program in order to decrease the bill [31]. Equation (22) gives the final responsive economic demand model for the MG in time interval t.

$$P_{b,t}^{L} = P_{b,t}^{L_0}\left[1 + \frac{E_{b,t}(\lambda_t^{TOU} - \lambda_{fix})}{\lambda_{fix}} + \sum_{t'(t' \neq t)=1}^{24} \frac{E_{b,tt'}(\lambda_{t'}^{TOU} - \lambda_{fix})}{\lambda_{fix}}\right] \quad \forall t \neq t' \tag{22}$$

where $E_{b,tt'}$ is the cross-price elasticity, which is defined as the demand variation in time interval t with respect to the price change in time interval t'; $E_{b,t}$ and $P_{b,t}^{L_0}$ are the self-price elasticity and primal load at bus b, respectively; λ_t^{TOU} is the TOU price; and λ_{fix} is the basic price of electricity.

D. Modelling Energy Storage System Constraints

The energy storage system constraints encompass the following:

$$0 \leq P_{s,t}^{ch} \leq \overline{P}_s^{ch} \tag{23}$$

$$0 \leq P_{s,t}^{dis} \leq \overline{P}_s^{dis} \tag{24}$$

$$0 \leq E_{s,t} \leq \overline{E}_s \tag{25}$$

$$E_{s,t} = E_{s,t-1} + \eta^{ch} P_{s,t}^{ch} \Delta t - \frac{1}{\eta^{dis}} P_{s,t}^{dis} \Delta t \tag{26}$$

where $P_{s,t}^{ch}$, $P_{s,t}^{dis}$, and $E_{s,t}$ are the charging power, discharging power, and energy of the energy storage system, respectively; $\overline{P}_s^{ch}$, $\overline{P}_s^{dis}$, and $\overline{E}_s$ are the upper limits of charging power, discharging power, and energy of the energy storage system, respectively; and η^{ch} and η^{dis} are the charging and discharging efficiencies of the energy storage system, respectively.

IV. Simulation Results and Discussion

The proposed method is executed on the 10-bus MG [28], the topology of which is demonstrated in Fig. 4. The MG is supplied by the upstream transmission network, along with three conventional generation units connected to buses 1, 5, and 6 and wind turbines connected to bus 8. An energy storage system with a capacity of 0.5 MWh and the maximum charging and discharging power of 0.15 kW and 0.32 kW, respectively, is installed at bus 10. The hourly load data are adopted from [32] with an active peak load of 3199 kW. The total installed capacity of wind turbines is 1.2 MVA. The lower and upper boundaries of the voltage amplitude at each bus are assumed to be 0.95 p.u. and 1.05 p.u., respectively. The standard deviation of the wind power generation and load is set to be 10% of the forecasted value [33]. $\mu - 3\sigma$ and $\mu + 3\sigma$ are selected as the boundaries of the uncertain space, since the probability of observing values within this interval in a normal distribution with a mean value of μ and standard deviation of δ is 0.9973. The value of the cost increment coefficient is set to be 1.5%. For simplicity, $it^{\max}$ is selected to be one to discuss all the results in the same situation. Additionally, technical parameter values of the generation units are adopted from [27] and listed in Table II. The cost coefficient of generation units is set to be 50 \$/MWh. It should be mentioned that, although our case study focuses on a single wind farm, the proposed method is scalable to accommodate multiple wind farms. Given the substantial correlation observed in renewable energy output of a distribution network [34], we can assume a correlation factor of 1.0 for all wind power generations. This assumption allows us to represent the uncertainty and feasible spaces in a two-dimensional format. In this case, the consumers participate in the TOU-DR program. The off-peak (01:00-07:00 and 24:00), mid-peak (08:00-11:00 and 21:00-23:00) and on-peak (12:00-20:00) levels are taken into consideration for the program. The values of the elasticity of Canadian power system are presented in Table III, which are the values of the elasticity of Canadian power system [35]. The TOU prices for three levels are regarded as the mean value of the predicted prices during that period. Therefore, consumers will transfer the load from high-price time intervals to low-price time intervals of the TOU-DR program and reduce the load with regard to the values of cross- and self-elasticity.

The forecasted market price and the TOU price are demonstrated in Fig. 5.

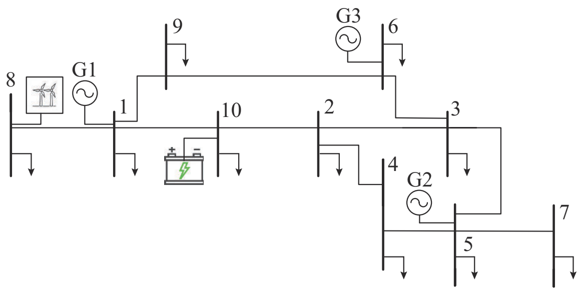

Fig. 4. Topology of 10-bus MG.

TABLE II
TECHNICAL PARAMETER VALUES OF GENERATION UNITS

Generation unit	$\bar{P}_i^{Gen}$ (MW)	R_i^{up} (MW/h)	R_i^{down} (MW/h)
G1	0.7	0.3	0.3
G2	1.2	0.5	0.4
G3	0.9	0.4	0.3

TABLE III
VALUES OF ELASTICITY OF CANADIAN POWER SYSTEM

Level	Value		
	On-peak	Mid-peak	Off-peak
On-peak	–0.15	0.08	0.07
Mid-peak	0.08	–0.14	0.05
Off-peak	0.07	0.05	–0.12

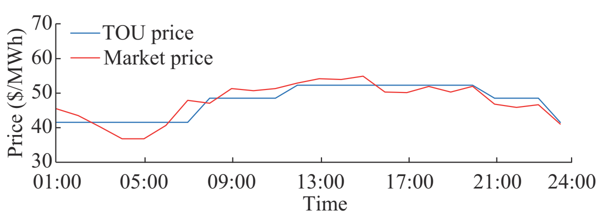

Fig. 5. Forecasted market price and TOU price.

In order to assess the influence of the cost limitation on the flexibility evaluation and improvement, two case studies, i. e., the proposed method (case study 1) and the proposed method without considering the cost constraint (case study 2) are designed. In fact, case study 2 explores the impact of the cost modeling on the flexibility evaluation. Moreover, case study 3, i. e., the proposed method considering the cost limitation and energy storage, is designed to explore the effect of energy storage on the flexibility index while considering cost limitations.

A. Case Study 1

In order to illustrate the connection of the two-dimensional feasible space and uncertain space, the former is acquired by traversing the directions in a specified step longitude (1°) in the uncertain space. First, the optimal scheduling of the MG is executed to obtain the minimum value of the system cost. Then, the maximum feasible deviation in different directions is obtained considering the cost limitation and physical constraints. Finally, the critical direction and flexibility index are achieved. This process is accomplished for both the cases without and with TOU-DR program applied to the MG.

Figure 6 shows the load profile before and after applying the TOU-DR program. According to this figure, the load decreases during peak load period (11:00-20:00) and increases during low load period (01:00-07:00 and 24:00). This study aims to analyze and quantify the effect of the TOU-DR program on the flexibility evaluation during on-peak and off-peak periods.

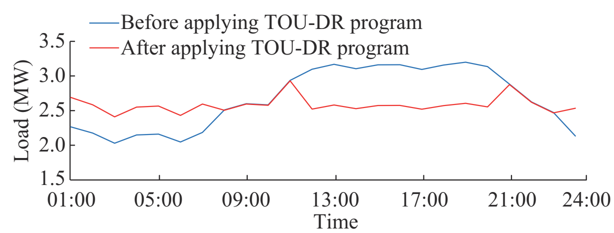

Fig. 6. Load profile before and after applying TOU-DR program.

In this subsection, two time intervals as on-peak periods and two time intervals as off-peak periods are discussed in detail. The results of other time intervals are very similar and are omitted here for the sake of space limitation. The flexibility of the MG during an on-peak period at 13:00 is evaluated as a sample. Figure 7(a) and (b) shows the uncertain and feasible spaces at 13:00 before and after applying the TOU-DR program, respectively.

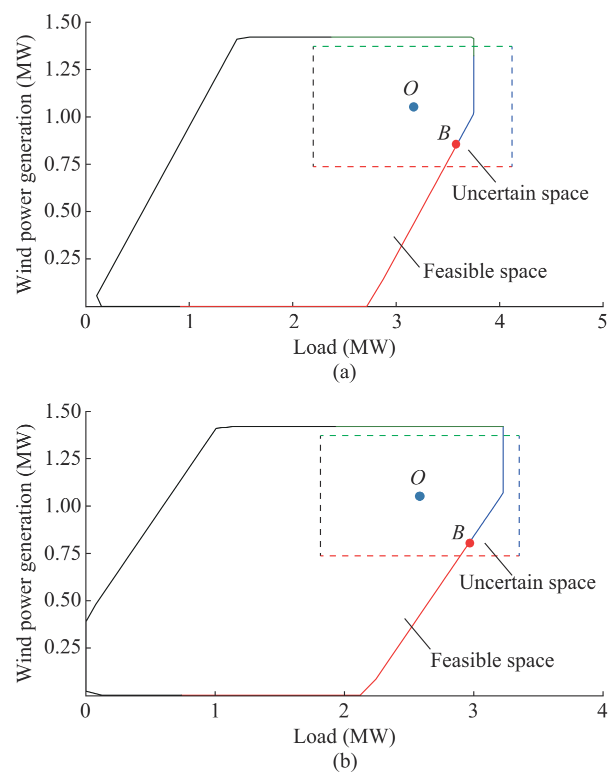

Fig. 7. Uncertain and feasible spaces at 13:00 before and after applying TOU-DR program in case study 1. (a) Before applying TOU-DR program. (b) After applying TOU-DR program.

The colors indicate the projection of each uncertain space onto the corresponding feasible space, with matching colors used to highlight the boundaries of the same projection in both spaces for clarity. Point O represents the operating point and point B is the critical point. According to Fig. 7(a), the amounts of the load and wind power generation at the operating point are 3169.1 kW and 1052.905 kW, respectively. Note that the illustrated traversing reflects only the direction, not the uncertain space boundary. Regarding Table IV and Fig. 7(a), the value of the flexibility index in the critical direction $(1,-1)$ is 0.711 and the corresponding wind power generation is at its lowest value. The *FI* reveals that there is a shortage of flexibility and the flexibility requirement is not satisfied in the operation of the MG. According to the simulation results, the cost constraint and the thermal capacity of lines have limited the flexibility. Hence, the load cannot reach the possible maximum amount at 13:00. In addition, the feasible space does not cover the entire uncertain space. The results after applying the TOU-DR program follows the same procedure, but *FI* is increased by 0.820. As the results show, applying the TOU-DR program has improved the flexibility index during peak load periods. Figure 8 shows similar results during another on-peak period at 18:00. At this time, the operation cost prevents the flexibility from increasing to its maximum.

TABLE IV
SIMULATION RESULTS FOR SAMPLE ON-PEAK AND OFF-PEAK PERIODS

Time	Case study 1			Case study 2			Case study 3		
	FI before TOU-DR	*FI* after TOU-DR	*FI* improvement after TOU-DR	*FI* before TOU-DR	*FI* after TOU-DR	*FI* improvement after TOU-DR	*FI* before TOU-DR	*FI* after TOU-DR	*FI* improvement after TOU-DR
03:00	1.000	0.951	–0.0490	1.000	1.000	0	1.000	1.000	0
04:00	0.974	0.839	–0.0135	1.000	1.000	0	1.000	1.000	0
13:00	0.711	0.820	+0.1090	0.733	1.000	+0.267	0.841	0.988	+0.147
18:00	0.729	0.806	+0.0770	1.000	1.000	0	0.864	0.972	+0.108

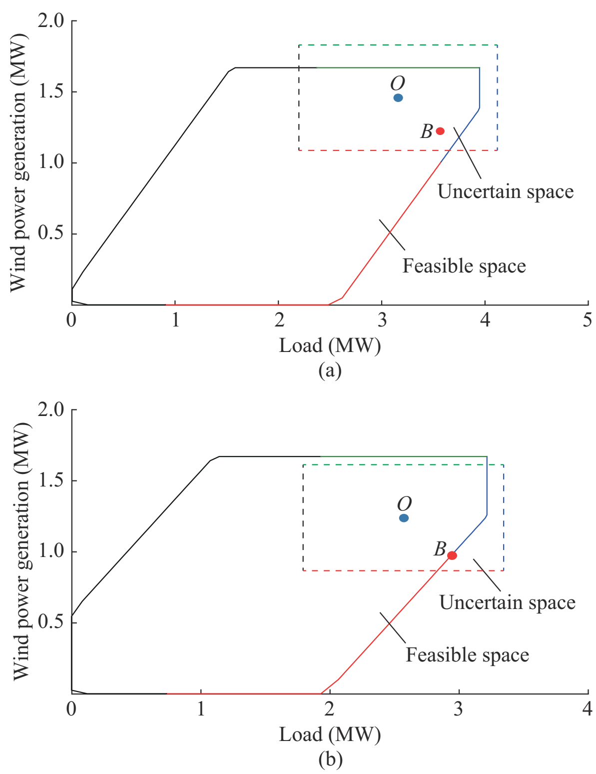

Fig. 8 Uncertain and feasible spaces at 18:00 before and after applying TOU-DR program in case study 1. (a) Before applying TOU-DR program. (b) After applying TOU-DR program.

The flexibility index at 03:00 and 04:00 is evaluated as a sample. During these periods, the demand has been increased after applying the TOU-DR program. Figure 9 illustrates the feasible spaces at 03:00 before and after applying the TOU-DR program. Referring to Fig. 9 and Table IV, the minimum value of δ^D in the feasible space before and after applying of the TOU-DR program is equal to 1 and 0.951, respectively. The flexibility evaluation output at 04:00 is slightly the same as that at 03:00 in terms of satisfying the power flow constraints. The only discrepancy is the lack of flexibility in the MG before applying the TOU-DR program. During these periods, the demand will be increased by applying the TOU-DR program, which will result in a higher operation cost of supplying the load. Consequently, the higher operation cost limits the cost-aware flexibility index.

Referring to the simulation results, the application of the TOU-DR program enhances flexibility during the periods when the TOU-DR program results in a decrease in the load (on-peak periods). Furthermore, during the periods when the TOU-DR program leads to an increase in the load (off-peak periods), the flexibility index is approximately the same before and after applying the TOU-DR program, showing no significant differences. It is noteworthy to mention that at all three load levels, the critical direction is $(1,-1)$, which represents a limitation in supplying the load of the MG, thereby violating the cost limitation.

B. Case Study 2

In order to investigate the effect of the cost constraint on the problem, the flexibility index has been calculated without considering this constraint. The feasible deviation in different directions is maximized and then the critical direction and the flexibility index are accomplished.

The results are summarized in Table IV. According to the results pertaining to 13:00, the flexibility index before applying the TOU-DR program is equal to 0.733, which is the same as case study 1. This is because in case study 1, in addition to the cost constraint, the apparent power of branches reaches the limit and restricts the load increment as well as the flexibility at 13:00. Similarly, in case study 2, the thermal capacity of branches will limit the load increment and the flexibility index as a consequence. The significant difference between the results of these two cases is associated with the way of power supply. In case study 1, the generation unit located at bus 1 produces power at its maximum capacity and the excess energy is sold in the market. Whereas, in case study 2, neglecting the cost constraint will cause fewer power generation of generation unit 1 and the MG provides the difference from the market in high-price time intervals. Therefore, neglecting the cost constraint will impose about 1% more cost on the network. In case study 2, the flexibility of the MG after applying the TOU-DR program is equal to 1, however, the cost increases by 1.1%, by improving the flexibility during only 1 hour. Figure 10 depicts the uncertain and feasible spaces at 13:00 before and after applying the TOU-DR program in case study 2. Simulation results at 13:00 reveal that without considering the cost constraint, there will be no flexibility shortage, however, the cost before and after applying the TOU-DR program is increased by 2.96% and 2.66% compared with that in case study 1, respectively. In addition, for the periods with off-peak demand, the renewable energy resources would satisfy the flexibility requirement with higher cost.

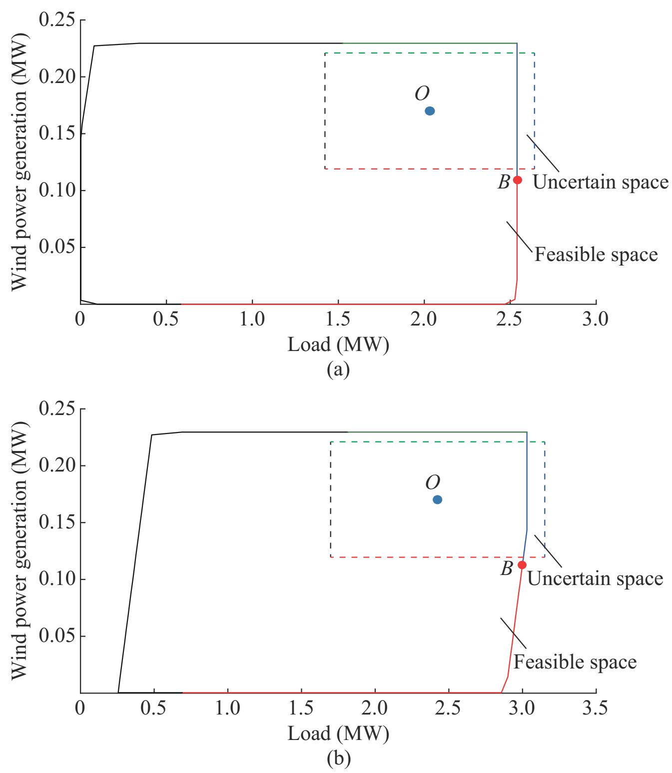

Fig. 9 Uncertain and feasible spaces at 03:00 before and after applying TOU-DR program in case study 1. (a) Before applying TOU-DR program. (b) After applying TOU-DR program

C. Case Study 3

This case study examines the impact of energy storage on the flexibility index. Since flexibility improvement is only required when considering cost constraint, we integrate the cost constraint into the analysis. It is evident that energy storage enhances the flexibility when there is an economic rationale for charging and discharging, factoring in its efficiencies. However, when integrating energy storage into the case study, the system remains idle, resulting in no change in flexibility. In this regard, to make energy generation costs and market prices comparable, forecasted prices are multiplied by 1.3. Consequently, the minimum operation cost C^{MG} is updated accordingly. The results are summarized in Table IV.

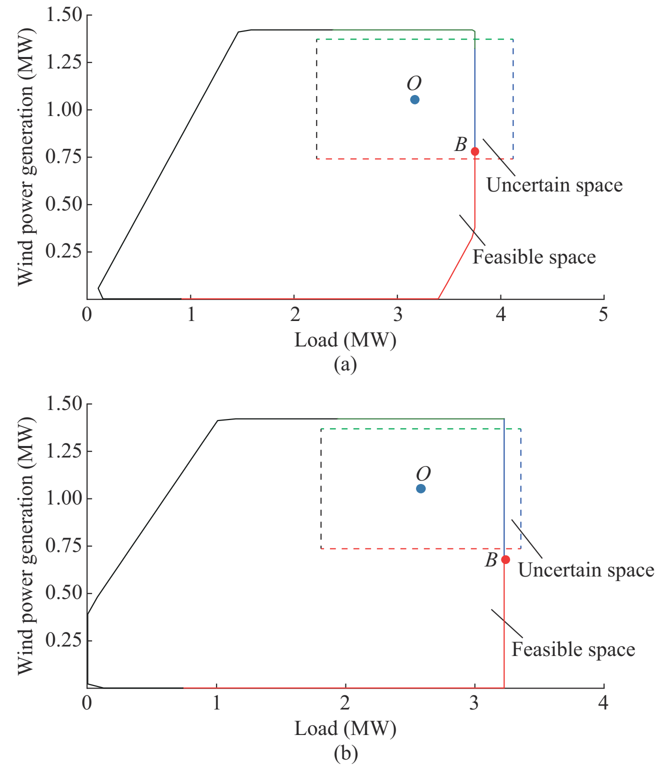

Fig. 10 Uncertain and feasible spaces at 13:00 before and after applying TOU-DR program in case study 2. (a) Before applying TOU-DR program. (b) After applying TOU-DR program.

The simulation results reveal a significant enhancement in the flexibility index upon integrating energy storage into the system. Consistent with previous cases, there is no discernible flexibility requirement during off-peak periods before and after applying the TOU-DR program. A crucial deduction from the simulations is that the utilization of an energy storage system yields a greater flexibility improvement after applying the TOU-DR program, compared with the case studies without an energy storage system.

V. CONCLUSION

This paper develops a cost-aware flexibility evaluation method for renewable energy integrated MGs. The proposed method is based on the feasibility analysis of the uncertain space of wind power generation and load; however, it is also applicable to PV-integrated systems. The analysis of the case studies confirms the effectiveness of the proposed method and the importance of considering the cost effect on flexibility evaluation problems.

Regarding the case studies, ignoring the cost constraint on flexibility evaluation problems leads to imposing extra costs on consumers. In case study 2, extra costs arise because the MG purchases the power from the market in high-price time intervals instead of maximizing its generation capacity to sell excess energy for revenue. The impact of the TOU-DR program as a flexibility resource on the feasible operation space and flexibility index of the MG is quantified. According to the case studies, the TOU-DR program enhances the flexibility index during on-peak periods. For example, in case study 1, the TOU-DR program increases the flexibility index by 15.3% at 13:00 and by 10.6% at 18:00. During off-peak periods, when there is no significant lack of flexibility, the flexibility index remains almost unchanged before and after applying the TOU-DR program. Furthermore, case study 3 emphasizes the effect of the energy storage system on MG flexibility improvement when it is cost-justified.

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