Managing the Microgrid Net Load Variability

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***Abstract*— This paper investigates and compares two options to control the microgrid net load variability resulted from high penetration renewable generation. The proposed options include 1) Local management, which limits the microgrid net load variability in the distribution level by enforcing a cap constraint, and 2) Central management, which recommends on building a new fast response generation unit to limit aggregated microgrid net load variability in the distribution level. In this paper, the power flow changes between two consecutive hours, i.e., power ramping is considered as the major representative of variability. A microgrid optimal scheduling model is developed using mixed-integer programming. Numerical simulations demonstrate the effectiveness of the proposed approach in identifying the more viable option.**

***Index Terms*—microgrid net load variability, microgrid optimal scheduling, renewable generation.**

NOMENCLATURE

Indices:

d	Index for day
i	Index for dispatchable units
t	Index for time

Parameters:

C	Generation cost coefficient
CSD	Shut down cost
CSU	Startup cost
D	Load demand
FC	Fixed O&M cost
GPC	Gas power plant capacity
H	Number of hours
k	Variability cap
MD	Minimum down time
MF	Number of hours the unit can be OFF
MN	Number of hours the unit can be ON
MU	Minimum up time
NL	No load cost
OCC	Overnight capital cost
P^{max}	Maximum generation capacity
P^{min}	Minimum generation capacity
PBP	Payback period
P_M^{max}	Capacity of transmission line between the utility and the microgrid
RD	Ramp down rate
RU	Ramp up rate
VC	Variable O&M cost
W	Wind power
ρ	Market price

Variables:

I	Commitment state of the dispatchable units
P	DER generated power
P_M	Microgrid net load
sd	Number of successive OFF hours
su	Number of successive ON hours
TC	Total operation cost
y	Startup indicator
z	Shut down indicator

I. INTRODUCTION

Microgrids are small-scale power systems which consist of at least one distributed energy resource (DER) and one load that are connected to the main distribution grid. The microgrid is an autonomous system; so it can island itself from the utility grid during outage events and reconnect itself when the disturbance is removed. The islanding capability makes the microgrid an important technological development in modern power systems as it can considerably increase the power system resilience and reliability [1]–[4]. Moreover, microgrids facilitate the control and operation of a large number of DERs by utilizing a local controller. Renewable energy resources, such as wind and solar, can also be efficiently integrated to the power system via microgrids.

Renewable generation, and in particular wind energy, is rapidly growing in power systems, primarily due to the falling cost of the technology and strict environmental mandates. In 2012, around 283.2 GW of total wind energy resources were installed worldwide, which is expected to reach 416.4 GW by the end of 2015 [5]–[11]. The wind generation variability, however, has presented a significant challenge in ensuring a reliable supply-demand balance when utilizing this technology. In [11], a study of integrating renewable generation within a microgrid is conducted. The study proposes operational controls to help with the renewable integration and managing the renewable generation variability. In [12], it is discussed that to ensure power system stability and supply reliability, the sudden wind power variability must be compensated by fast response generation units, such as natural gas or hydro. As the penetration of wind generation increases in the microgrid and there is a high microgrid penetration in the utility grid, the wind power variability may cause a severe negative impact. Studies conducted by the California ISO suggests that the rapid changes in renewable generation can cause significant challenges in supply-demand balance, result in over-generation risk especially in nighttime hours when the power demand is low, and require increased flexibility in the system in terms of fast ramping (see Fig. 1) [13].

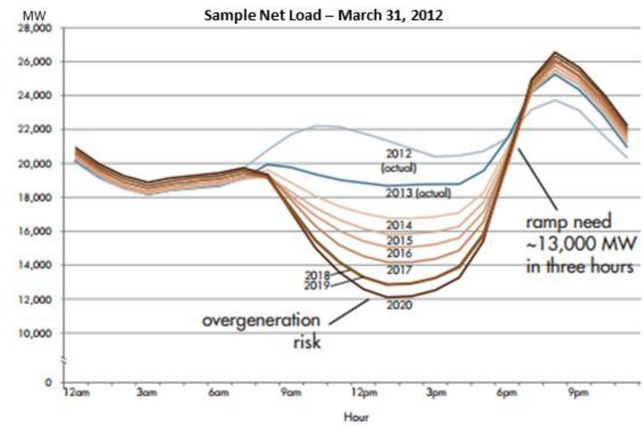

Fig. 1. The California ISO duck curve [13]

A reliable coordination of renewable generation within the microgrids requires a viable microgrid scheduling model. The microgrid optimal scheduling problem determines the least-cost schedule of local loads and DERs as well as the transferred power while considering prevailing operational constraints. The microgrid optimal scheduling problem and its formulation can be found in [14]–[17]. This paper builds upon the available studies in the literature to develop a microgrid optimal scheduling model that incorporates microgrid net load variability limits. This model, furthermore, will be used to analyze the local management option for limiting microgrid net load variability. The solution will be compared with the central variability management option of installing a centralized power plant from an economic perspective. The levelized cost of energy (LCOE) will be moreover used as an alternative measure to ensure that the decision is made correctly. LCOE is a convenient measure that integrates the capital cost, fuel costs, fixed and variable operations and maintenance (O&M) costs, and financing costs to obtain one fixed number representing the energy cost of any specific generation type [18].

The rest of this paper is organized as follows. The proposed model is outlined in Section II and formulated in Section III. Numerical simulations are presented in Section IV and the paper is concluded in Section V.

II. Model Outline

A. Microgrid Components

The microgrid components that are modeled in the proposed microgrid optimal scheduling problem include local generation units and loads. The local generation units can be either dispatchable or nondispatchable. Dispatchable units can be controlled by adding operation constraints to the optimal scheduling problem depending on the unit type such as generation limits, minimum on/off time limits, thermal limits, and ramping rate limits. Nondispatchable units are typically renewable energy resources such as wind turbines and solar photovoltaic which cannot be controlled by the microgrid due to the uncontrollable nature of the primary source of energy.

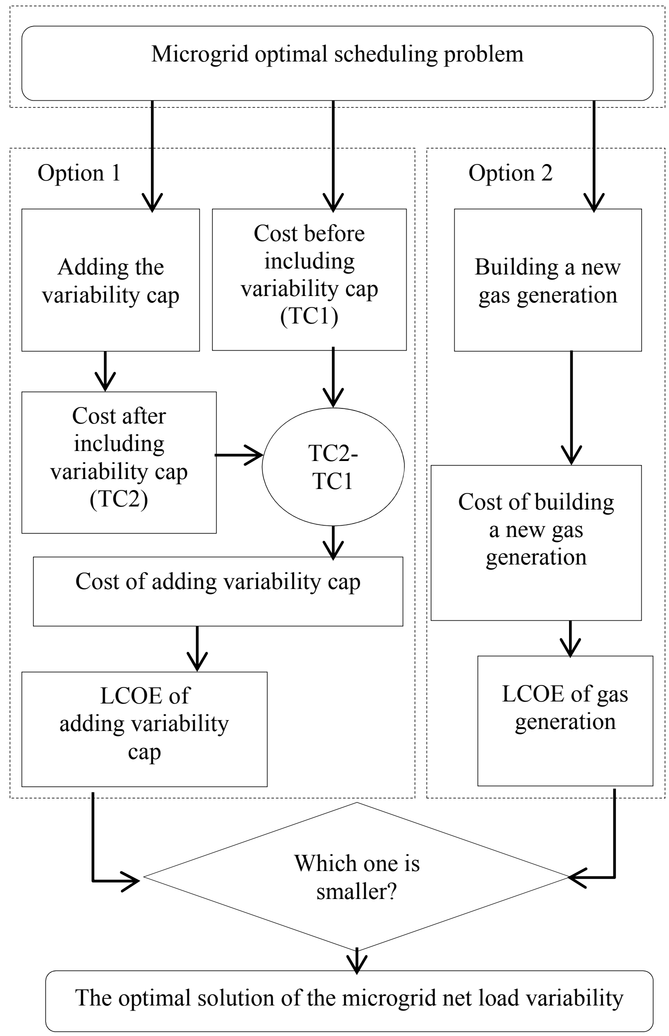

Fig. 2. Proposed microgrid net load variability-limiting model

B. Microgrid net load variability management model

Fig. 2 depicts the flowchart of the proposed model. The main objective of this model is to find the optimal solution to limit the microgrid net load variability between two consecutive hours (i.e., a ramping constraint). The model consists of an optimal scheduling problem and two cost calculation problems. The optimal scheduling problem determines the units schedule, the utility transferred power with the microgrid, and the total operation cost of the microgrid before adding the microgrid net load variability constraint. In the local management option, a variability constraint (i.e., a cap) will be added to the problem to restrict the net load variability between any two consecutive hours. A new utility transferred power flow will be compared with the old one and the impact of adding the constraint is observed. A new total operation cost will be obtained. When the microgrid net load variability is forced to be small between two consecutive hours, the total operation cost will be increased depending. The difference between the new and the old operation costs is calculated to find the cost of adding the cap. In the central management option, a new fast response generation unit (here a gas unit) is considered to be built to deal with the aggregated microgrid net load variability in the distribution level. The planning cost of building the new unit is calculated and annualized. After calculating the cost of both options, a comparison between them will be conducted to find the more economical solution. Alternatively, the LCOE of each option will be calculated in order to enable further comparison. The option that has the smallest LCOE is considered to be the optimal solution of limiting the microgrid net load variability.

III. MODEL FORMULATION

A. Microgrid optimal scheduling problem formulation

The microgrid optimal scheduling problem is modeled by mixed-integer programming. The objective of the optimal scheduling problem is to minimize the total operation cost of the microgrid (1) subject to operational constraints (2)-(8). The first term in the objective represents the generation cost of the dispatchable units, no-load cost, and startup and shut down costs. The second term is the cost of purchasing power from the utility grid. The microgrid net load (also known as the transferred utility power) is the transferred power from or to the microgrid through the point of common coupling (PCC). The transferred power cannot exceed the capacity of the transmission line connecting the utility grid to the microgrid as modeled in (2). The microgrid net load might be positive (i.e., microgrid imports power from the utility where the transferred power is less expensive than local generation). On the other hand, when the microgrid net load is negative, microgrid delivers power to the utility grid since the local generation is less expensive than the transferred power. The power balance equation (3) guarantees that the summation of local generation and transferred power equals the hourly microgrid net load. The nondispatchable unit generation (here the wind generation) is represented as a negative load in (3).

The microgrid components are modeled in (4)-(8). The maximum and minimum generation capacity limits for each dispatchable unit are modeled by (4). The ramping up and down rate limits between two consecutive hours are represented by (5)-(6). The minimum number of successive hours that the unit can be up or down is shown by (7)-(8). The commitment state of a dispatchable unit, the startup state and the shut down state are binary variables. The commitment state I will be one when the unit is ON, otherwise it is zero. The startup indicator y is one when the unit is started up, otherwise it is zero. The shut down indicator z will be one when the unit is shut down, otherwise it is zero.

$$\min \sum_i \sum_t \sum_d [C_i(P_{itd}) + NL_i I_{itd} + CSU_i y_{itd} + CSD_i z_{itd}] + \sum_t \sum_d \rho_{td} P_{M,td} \tag{1}$$

$$-P_M^{\max} \le P_{M,td} \le P_M^{\max} \qquad \forall t, \forall d \tag{2}$$

$$\sum_i P_{itd} + P_{M,td} = D_{td} - W_{td} \qquad \forall t, \forall d \tag{3}$$

$$P_i^{\min} I_{itd} \le P_{itd} \le P_i^{\max} I_{itd} \qquad \forall i, \forall t, \forall d \tag{4}$$

$$P_{itd} - P_{i(t-1)d} \le RU_i \qquad \forall i, \forall t, \forall d \tag{5}$$

$$P_{i(t-1)d} - P_{itd} \le RD_i \qquad \forall i, \forall t, \forall d \tag{6}$$

$$su_{itd} \ge MU_i z_{i(t+1)d} \qquad \forall i, \forall t, \forall d \tag{7}$$

$$sd_{itd} \ge MD_i y_{i(t+1)d} \qquad \forall i, \forall t, \forall d \tag{8}$$

The startup and shut down indicators are determined as in (9)-(10). The startup and shut down counters are modeled as in (11)-(14).

$$I_{itd} - I_{i,t-1,d} = y_{itd} - z_{itd} \qquad \forall i, \forall t, \forall d \tag{9}$$

$$y_{itd} + z_{itd} \le 1 \qquad \forall i, \forall t, \forall d \tag{10}$$

$$0 \le su_{itd} \le MN_i I_{itd} \qquad \forall i, \forall t, \forall d \tag{11}$$

$$(MN_i + 1) I_{itd} - MN_i \le su_{itd} - su_{i,t-1,d} \le 1 \qquad \forall i, \forall t, \forall d \tag{12}$$

$$0 \le sd_{itd} \le MF_i (1 - I_{itd}) \qquad \forall i, \forall t, \forall d \tag{13}$$

$$1 - (MF_i + 1) I_{itd} \le sd_{itd} - sd_{i,t-1,d} \le 1 \qquad \forall i, \forall t, \forall d \tag{14}$$

B. Adding variability cap

The local management option adds a variability cap to the microgrid net load, i.e., the power transferred with the utility grid. The variability cap is modeled in this paper for the inter-hour variability (15) and the inter-day variability (16).

$$\left| P_{M,td} - P_{M,(t-1)d} \right| \le k \qquad \forall t > 1, \forall d \tag{15}$$

$$\left| P_{M,1d} - P_{M,24(d-1)} \right| \le k \qquad \forall t, \forall d > 1 \tag{16}$$

The optimal scheduling problem will be used again to find the optimal scheduling of microgrid units after adding the variability limit constraints (15) and (16). A new microgrid units schedule and a new total operation cost (TC2) will be obtained. The cost of the local management option can be found by calculating the cost increase after adding the variability cap as in (17).

$$\text{Option 1: } Cost = TC2 - TC1 \tag{17}$$

The variability cap cost ($/yr) will be levelized to obtain the LCOE in $/MWh for the cap value. The LCOE of the variability cap will be compared with the LCOE of gas generation for making the decision on optimal solution.

C. Building a new gas generation

Building a new gas generation is another option to deal with the increasing variability in the microgrid net load. The cost of building a new gas power generation is divided into capital and operation and maintenance (O&M) costs. The operation cost is also divided into fixed O&M cost and variable O&M cost. The cost of the central management option can be calculated as in (18).

$$\text{Option 2: } Cost = \left[\frac{GPC*OCC}{PBP}\right] + \left[GPC*FC\right] + \left[GPC*VC*H\right] \tag{18}$$

The LCOE for gas generation is determined in order to compare it with the LCOE for the adding variability cap option.

IV. Numerical Simulations

The proposed microgrid net load variability-limiting model is applied to a test microgrid with four dispatchable units and one nondispatchable unit (wind turbine). The characteristic of generating units and nondispatchable unit are given in Table I. One-year time horizon of forecasted wind, load and market price is used in the studies. Mixed integer programming is used to model and solve the microgrid optimal scheduling problem. The following cases are studied:

Case 1: Adding a variability cap (local management option)

Case 2: Building a new gas generation (central management option)

Case 1: Adding a variability cap is the first option to limit the microgrid net load variability. The solved optimal scheduling problem is used as a base case to determine the total operation cost before limiting the microgrid net load variability. Different values of variability cap are added as a constraint to the optimal scheduling problem. The values of variability cap are ranging from 32 to 14 MW, as the maximum power ramp between two consecutive hours is 32 MW. The impact of adding variability cap on the total operation cost is shown in Table II for each reduction value of the variability cap. Figs. 3 and 4 show the cost curve and the LCOE curve of each reduction value of the variability cap, respectively.

TABLE I: CHARACTERISTIC OF GENERATING UNITS (D: DISPATCHABLE, ND: NONDISPATCHABLE)

Unit	Type	Cost Coefficient ($/MWh)	Min.-Max. Capacity (MW)	Min. Up/Down Time (h)	Ramp Up/Down Rate (MW/h)
G1	D	27.7	4-10	3	5
G2	D	39.1	4-10	3	5
G3	D	61.3	2-6	1	3
G4	D	65.6	2-6	1	3
G5	ND	0	0-4.16	-	-

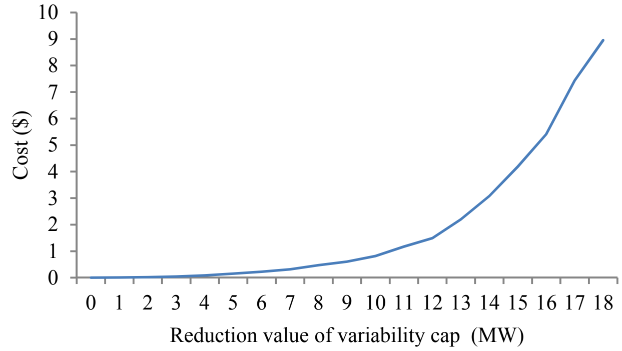

Fig. 3. The cost ($) of each reduction value of the variability cap

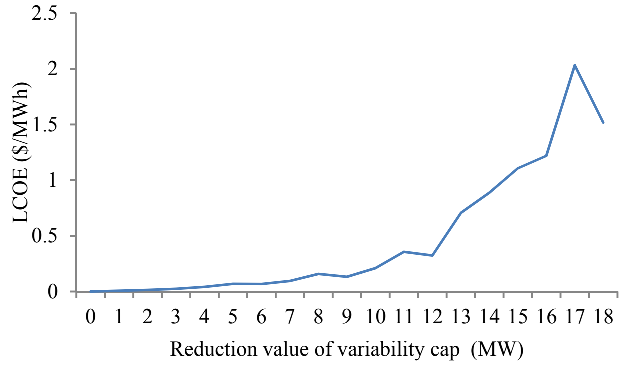

Fig. 4. The LCOE ($/MWh) of each reduction value of the variability cap

TABLE II: THE IMPACT OF ADDING VARIABILITY CAP ON THE TOTAL OPERATION COST

The reduction value of the variability cap (MW)	The Total Operation Cost ($/yr)	Variability Cap Impact ($/yr)	Increased percentage of the total cost (%)
0	3,298,764.81	0.00	0.000
1	3,2988,28.28	63.47	0.002
2	3,298,,951.71	186.90	0.006
3	3,299,157.72	392.91	0.012
4	3,299,522.56	757.75	0.023
5	3,300,120.17	1,355.36	0.041
6	3,300,709.51	1,944.70	0.059
7	3,301,531.67	2,766.86	0.084
8	3,302,908.66	4,143.86	0.126
9	3,304,056.97	5,292.16	0.160
10	3,305,888.04	7,123.24	0.216
11	3,309,006.74	10,241.93	0.310
12	3,311,828.03	13,063.22	0.396
13	3,317,997.43	19,232.62	0.583
14	3,325,759.41	26,994.60	0.818
15	3,335,443.35	36,678.54	1.112
16	3,346,110.91	47,346.10	1.435
17	3,363,908.34	65,143.54	1.975
18	3,,377,189.12	78,424.31	2.377

Case 2: The second option is building a new gas generation unit in the distribution network to address the microgrid net load variability. The capacity of the gas generation unit should be equal to the variability cap value. The annualized cost of building a 1MW gas generation, which is only for 1 MW/h variability cap, is around $80,000/yr. So, the cost of

building a new gas generation is significantly greater than the cost of adding a 1 MW variability cap. Similarly, for the rest of the variability cap values, adding variability cap is more economical than building a new gas generation unit.

Another measure (i.e., the LCOE) is used to decide the more economically viable option. The average LCOE of gas generation in the United States is $66.3/MWh [18]. Fig. 5 depicts the LCOE for each variability cap along with the LCOE of gas generation. It is obvious that the gas LCOE is much greater than the LCOE of all variability caps. So, adding a variability cap is always a more viable decision than building a new gas generation unit.

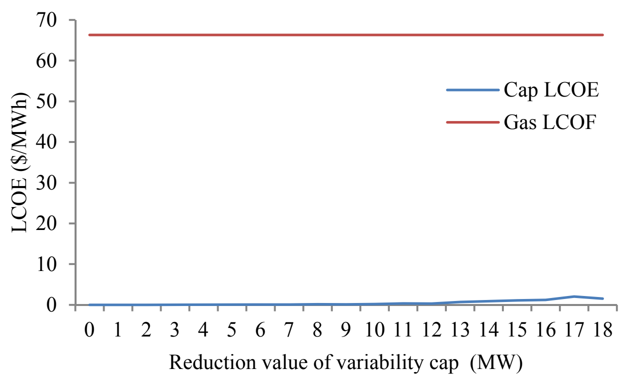

Fig. 5. The LCOE of both reduction value of the variability cap and gas generation

V. Conclusion

An efficient model for limiting the microgrid net load variability was proposed. Two options were considered, were the option investigates the addition of a variability cap to limit the microgrid net load variability within two successive hours and the second option investigated the addition of a new gas generation unit to the distribution system. The impact of adding the cap on the total operation cost in the first option was noticed by comparing the microgrid total operation cost in both cases (i.e., the original solution and the solution after adding the variability cap). The difference was considered to be the cost of adding variability cap. The cost of build a new gas generation and the LCOE of gas generation were further calculated for comparison purposes. The model was tested and analyzed on a microgrid test system. The numerical simulations were shown that adding a variability cap on the microgrid net load was always the more economical solution for addressing the microgrid net load variability.

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