IEEE TRANSACTIONS ON SMART GRID, VOL. 5, NO. 4, JULY 2014

Resiliency-Oriented Microgrid Optimal Scheduling

Amin Khodaei, *Member, IEEE*

***Abstract*—One of complementary value propositions of microgrids is to improve power system resiliency via local supply of loads and curtailment reduction. This subject is investigated in this paper by proposing a resiliency-oriented microgrid optimal scheduling model. The proposed model aims at minimizing the microgrid load curtailment by efficiently scheduling available resources when supply of power from the main grid is interrupted for an extended period of time. The problem is decomposed to normal operation and resilient operation problems. The normal operation problem solution, i.e., unit commitment states, energy storage schedules, and adjustable loads schedules, is employed in the resilient operation problem to examine microgrid capability in supplying local loads during main grid supply interruption. The schedule is revised via resiliency cuts if a zero mismatch is not obtained. Prevailing operational uncertainties in load, non-dispatchable generation, and the main grid supply interruption time and duration are considered and captured using a robust optimization method. The final solution, which is obtained in an iterative manner, is economically optimal, guarantees robustness against prevailing operational uncertainties, and supports a quick islanding with minimum consumer inconvenience and load curtailment. Numerical simulations demonstrate the effectiveness of the proposed resiliency-oriented microgrid optimal scheduling model applied to a test microgrid.**

***Index Terms*—Adjustable load, distributed energy resource (DER), microgrid optimal scheduling, normal and resilient operation, resiliency.**

NOMENCLATURE

Indices:

b	Index for energy storage.
d	Index for loads.
i	Index for DERs.
s	Index for scenarios.
t	Index for time.
$\wedge$	Index for calculated variables.

Sets:

D	Set of adjustable loads.
G	Set of dispatchable units.
P	Set of primal variables.
S	Set of energy storage systems.
U	Set of uncertain parameters.
W	Set of non-dispatchable units.

Parameters:

DR	Ramp down rate.
DT	Minimum down time.
E	Load total required energy.
$F(.)$	Generation cost.
K_d	Inconvenience penalty factor.
MC	Minimum charging time.
MD	Minimum discharging time.
MU	Minimum operating time.
RR	Permissible power adjustment.
U	Outage state of main grid line/Islanding state.
UR	Ramp up rate.
UT	Minimum up time.
α, β	Specified start and end times of adjustable load.
ρ	Market price.

Variables:

C	Energy storage system stored energy.
D	Load demand.
I	Commitment state of dispatchable unit.
P	DER output power.
P_M	Main grid power.
SD	Shut down cost.
SL_1, SL_2	Slack variables.
SU	Startup cost.
T^{ch}	Number of successive charging hours.
T^{dch}	Number of successive discharging hours.
T^{on}	Number of successive ON hours.
T^{off}	Number of successive OFF hours.
u	Energy storage discharging state.
v	Energy storage charging state.
w	Power mismatch.
z	Adjustable load state.

Manuscript received January 18, 2014; accepted March 08, 2014. Date of current version June 18, 2014. Paper no. TSG-00043-2014.

The author is with the Department of Electrical and Computer Engineering, University of Denver, Denver, CO 80210 USA (e-mail: amin.khodaei@du.edu).

Color versions of one or more of the figures in this paper are available online at http://ieeexplore.ieee.org.

Digital Object Identifier 10.1109/TSG.2014.2311465

λ, μ, π Dual variables.

Δ_d Deviation in adjustable load operating time interval.

I. INTRODUCTION

SIGNIFICANT impacts of weather related incidents and natural disasters on electric power systems and subsequent economic and social disruptions have resulted in a growing global need in addressing the issue of power system resiliency. Resiliency represents the ability of power systems to withstand low-probability high-impact incidents in an efficient manner while ensuring the least possible interruption in supply of electricity, and further enabling a quick recovery and restoration to the normal operation state. A novel and viable solution to resiliency issues in power systems is to deploy microgrids. Microgrids are small-scale power systems with at least one distributed energy resource (DER) and one load with clearly defined electrical boundaries and ability of self-supply and islanding. Microgrids were initially introduced to address the emergence of high-penetration DERs in distribution networks and further identified as valuable alternatives to centralized generation and bulk transmission in power systems operation and planning [1]–[6]. Microgrid deployment is becoming an increasingly attractive solution for electricity customers who cannot rely on supply of power from the main grid, and/or are seeking economic benefits from a locally generated power. Electricity customers within a microgrid could benefit from the power supplied form local resources when there is a failure in the main grid and the supply of power is interrupted. Furthermore, the microgrid excess generation could be sold back to the main grid to provide financial benefits, primarily in terms of electricity payment reductions, for customers. Microgrids introduce unique opportunities in power system operation and planning such as improved reliability, higher power quality, reduction in carbon emission, utilization of less costly renewable energy sources, offering energy efficiency, reducing the total system expansion planning cost, and providing a quick and efficient response for supplying loads in remote areas [7].

In addition to mentioned advantages, microgrids could be employed to improve power system resiliency by lowering the possibility of load shedding. Based on the definition, microgrids can connect and disconnect to/from the main grid distribution network and operate in either grid-connected or islanded modes. The microgrid islanding is typically performed to rapidly disconnect the microgrid from the main distribution network in order to protect microgrid components from upstream disturbances, or to shield voltage sensitive loads from significant voltage drops in the main grid [8], [9]. Therefore, the microgrid islanded operation could provide an efficient solution for supplying local loads when the main grid power is not available or the distribution network is faulty. The microgrid scheduling in grid-connected and islanded modes is performed by the microgrid master controller based on economic and security considerations. The master controller determines the microgrid interaction with the main grid, the decision to switch between grid-connected and islanded modes, and optimal schedule of local resources. The microgrid islanding capability represents this technology as a viable solution to address power system resiliency issues and has attracted significant attention in recent years [10], [11]. Resiliency improvement is considered as one of complementary value propositions provided by microgrids achieved via promoting the dispersion of power resources and islanding [12].

The resiliency benefits of microgrids are widely discussed in the literature; however, the mathematical modeling of microgrid optimal scheduling based on resiliency considerations is limited. Existing studies on microgrid resiliency can be found in [13]–[21]. In [13], adequacy constraints are considered to ensure sufficient operating margin in the microgrid economic operation and cover critical loads in case of upstream network faults. The concept of intelligent distributed autonomous power systems is proposed in [14] for building a resilient and environment-friendly customer-based microgrid, where the demand side management is employed to ensure that critical loads are served during emergency conditions. A frequency droop control system for a microgrid is proposed in [15] to extend capabilities of a resilient microgrid to a conventional distribution network. A study in [16] derives a sequence of control actions to be adopted for multi-microgrid systems service restoration and subsequent operation in islanded mode. It is shown that the feasibility of the sequence of control actions allows the reduction of load restoration times and improves system resiliency. A study in [17] reports on recent research directed towards employing distributed multi-agent architectures to achieve resilient self-healing power systems through independent management of microgrids. It is further discussed that interconnected microgrids are viable solutions to power system resiliency issues. A microgrid to serve a residential area located in a hurricane path is proposed in [18]. A phase droop control and a central power management controller are proposed as control means to stabilize the system when it is subject to disturbances. In [19], development of advanced microgrid load management functionalities to manage microgrid storage, electric vehicles, and load responsiveness, to improve microgrid resilience following the islanding events is presented. A planning approach for building resilient microgrids, by strategically deploying distributed generators in a distribution system, is proposed in [20], which aims at optimizing microgrid vulnerability, reliability, and economy. The optimization model is solved by a combination of multi-agent systems and particle swarm optimization. A study in [21] proposes multi-objective optimization for evaluating the sustainable design and operation of DERs in microgrids. A resiliency index is defined to account for the capacity of the power system to self-recover to a new normal state after experiencing an unanticipated catastrophic event.

In this paper, a resiliency-oriented microgrid optimal scheduling model is proposed. A centralized scheduling model is adopted in which the master controller collects all the required information for microgrid scheduling and performs a centralized operation and control. The proposed centralized model ensures the secure microgrid operation and is suitable for application of optimization techniques. The microgrid normal operation, when connected to the grid, is coordinated with a resilient operation for enabling a rapid switching between these two modes without interruption in supply of loads. At normal operation, the microgrid is connected to the main grid distribution network, thus it would schedule local resources and

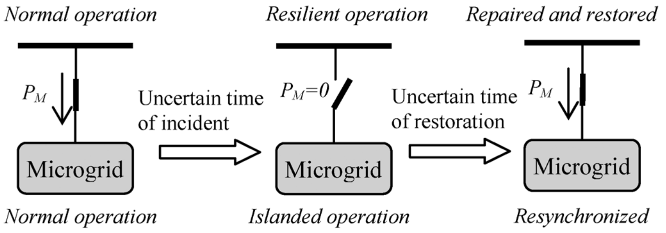

Fig. 1. Microgrid operation: before the incident; during the main grid supply interruption; and after the main grid repair and restoration.

transfer power with the main grid to minimize the microgrid operation cost. In case of main grid disturbances, however, the microgrid is switched over to resilient operation, i.e., the islanded mode, to supply local loads and ensure a resilient operation. Prevailing uncertainties make the problem very challenging to solve. It is assumed that the microgrid operator would be able to estimate the time that the electricity infrastructure would be affected, i.e., the main grid supply would be interrupted, and accordingly, decide on the time that the microgrid must be switched to the islanded mode. However, the duration of the islanding is uncertain and depends on how fast the main grid would be repaired and restored. Fig. 1 shows three stages of microgrid operation which includes before the incident (normal operation), during the main grid supply interruption (resilient operation), and after the main grid repair and restoration (resynchronized). Other uncertain factors include microgrid load and variable renewable generation forecasts. Although these forecasts are performed for a short-time period, i.e., from few hours to few days depending on the main grid repair and restoration time, forecast errors would significantly impact the microgrid optimal scheduling solution. A robust optimization method is employed to account for uncertainties in load and generation forecasts. The Benders decomposition method is employed to decouple and coordinate the normal operation and the resilient operation problems. The microgrid optimal scheduling model proposed in [22] is considered as the basis of this work and extended considerably to make the model applicable for resiliency applications. In the proposed model, uncertainty in load, renewable generation, and time and duration of incidents are efficiently captured. The curtailment of local loads when sufficient generation is not available is also considered properly in the model for enhancing model practicality. In addition, dispatchable units' capability in revising their generation when switching to resilient operation is restricted via permissible power adjustment constraints.

The rest of the paper is organized as follows. Sections II and III, respectively, present the model outline and formulation of the resiliency-oriented microgrid optimal scheduling problem. Section IV presents illustrative examples to show the proposed model applied to a test microgrid. Discussion on features of the proposed model and concluding remarks are provided in Sections V and VI, respectively.

II. RESILIENCY-ORIENTED MICROGRID OPTIMAL SCHEDULING MODEL OUTLINE

An accurate modeling of microgrid components, as well as identification of sources of uncertainty, is required to ensure the efficient microgrid optimal scheduling with resiliency considerations. Microgrid components, including fixed and adjustable loads, dispatchable and non-dispatchable units, and energy storage, are identified and discussed in detail in the literature [22]. The issue of uncertainty in microgrid scheduling, however, requires more investigation. Uncertainty refers to the fact that some factors, having a major influence on scheduling decisions, are not under control of the microgrid master controller and/or cannot be predicted with certainty. Based on this definition, two major sources of uncertainty can be identified in the microgrid optimal scheduling problem: forecast errors, and main grid supply interruption. The microgrid load, the non-dispatchable unit generation, and the market price cannot be accurately forecasted. Forecasts depend on a variety of factors which are out of control of the microgrid master controller, such as weather and site conditions, decisions of market players, transmission network congestion, etc., thus the forecast would not be completely accurate. This issue persists even in scheduling problems with relatively short horizons. Main grid supply interruption is also uncertain as the time of incidents is unknown. Furthermore, depending on the range and severity of outages in the main grid, the required time to repair the power system and restore the power supply would vary. For ensuring resiliency, the microgrid master controller must plan ahead for main grid supply interruptions while taking forecast uncertainties into account, and accordingly perform a seamless islanding when required.

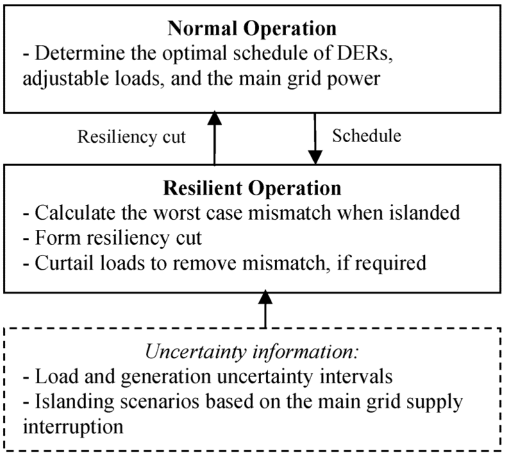

Fig. 2. Resiliency-oriented microgrid optimal scheduling model.

Fig. 2 depicts the flowchart of the proposed resiliency-oriented microgrid optimal scheduling model. The problem is decomposed into a normal operation problem and a resilient operation problem. The normal operation problem determines the optimal schedule of units, energy storage, and adjustable loads, as well as the power transfer with the main grid. The optimal schedule is tested in the resilient operation problem to ensure generation adequacy for a feasible islanding. The resilient operation problem minimizes the power mismatches between microgrid generation and load. A robust optimization method is employed for capturing uncertainties, in which it is assumed that uncertain parameters belong to convex and bounded uncertainty intervals. Forecast uncertainties are captured by determining the worst case solution of the resilient operation problem, i.e., the highest mismatch that would be resulted when uncertain parameters fluctuate in their associated uncertainty intervals. The uncertainty of the main grid supply interruption is captured by defining a set of islanding scenarios with various start times and durations. A reliable operation of the microgrid in islanding scenarios would ensure resiliency. The market price forecast error is overlooked in the model since it would not appear in the microgrid resilient operation problem.

The microgrid must have sufficient online capacity in the normal operation to be able to supply the loads in the resilient operation. If the mismatch is not zero, i.e., a feasible islanding cannot be obtained, the normal operation solution is revised. The revision of the normal operation solution is performed via three actions: 1) changing the commitment of dispatchable units and the schedule of the energy storage, 2) changing the schedule of adjustable loads, and 3) load curtailment. The change in the commitment of dispatchable units and the schedule of the energy storage are considered as the first action since it may increase the operation cost but does not result in any inconvenience for consumers. If this change does not result in a feasible islanding, the model would impose changes to the schedule of adjustable loads. This change would enable shifting away adjustable loads from islanding hours and accordingly reduce mismatches. The inconvenience realized by consumers as a result of this change is penalized in the normal operation problem objective. If after these revisions a feasible islanding is not yet obtained, the microgrid master controller would curtail loads as a last resort. The load curtailment is performed with the objective of removing power mismatches and matching available generation with the load. Loads are curtailed based on the load criticality criterion, i.e., less important loads are curtailed first, and if needed, more critical loads are considered for curtailment. These changes are governed by forming resiliency cuts in the resilient operation problem and sending back to the normal operation problem for subsequent iterations. The final solution is obtained when all mismatches are zero and all islanding scenarios are guaranteed feasible.

III. RESILIENCY-ORIENTED MICROGRID OPTIMAL SCHEDULING FORMULATION

Normal Operation Problem Formulation:

$$Min \sum_t \sum_{i \in \mathrm{G}} \left[F_i(P_{it}) I_{it} + SU_{it} + SD_{it} \right] + \sum_t \rho_t P_{M,t} + \sum_{d \in \mathrm{D}} K_d \Delta_d \tag{1}$$

$$\sum_i P_{it} + P_{M,t} = \sum_d D_{dt} \quad \forall t \tag{2}$$

$$-P_M^{\max} \le P_{M,t} \le P_M^{\max} \quad \forall t \tag{3}$$

$$P_i^{\min} I_{it} \le P_{it} \le P_i^{\max} I_{it} \quad \forall i \in \mathrm{G},\ \forall t \tag{4}$$

$$P_{it} - P_{i(t-1)} \le UR_i \quad \forall i \in \mathrm{G},\ \forall t \tag{5}$$

$$P_{i(t-1)} - P_{it} \le DR_i \quad \forall i \in \mathrm{G},\ \forall t \tag{6}$$

$$T_i^{\mathrm{on}} \ge UT_i \left(I_{it} - I_{i(t-1)} \right) \quad \forall i \in \mathrm{G},\ \forall t \tag{7}$$

$$T_i^{\mathrm{off}} \ge DT_i \left(I_{i(t-1)} - I_{it} \right) \quad \forall i \in \mathrm{G},\ \forall t \tag{8}$$

$$P_{it} \le P_{it}^{\mathrm{dch,max}} u_{it} - P_{it}^{\mathrm{ch,min}} v_{it} \quad \forall i \in \mathrm{S},\ \forall t \tag{9}$$

$$P_{it} \ge P_{it}^{\mathrm{dch,min}} u_{it} - P_{it}^{\mathrm{ch,max}} v_{it} \quad \forall i \in \mathrm{S},\ \forall t \tag{10}$$

$$u_{it} + v_{it} \le 1 \quad \forall i \in \mathrm{S},\ \forall t \tag{11}$$

$$C_{it} = C_{i(t-1)} - P_{it} \quad \forall i \in \mathrm{S},\ \forall t \tag{12}$$

$$C_i^{\min} \le C_{it} \le C_i^{\max} \quad \forall i \in \mathrm{S},\ \forall t \tag{13}$$

$$T_i^{\mathrm{ch}} \ge MC_i \left(u_{it} - u_{i(t-1)} \right) \quad \forall i \in \mathrm{S},\ \forall t \tag{14}$$

$$T_i^{\mathrm{dch}} \ge MD_i \left(v_{it} - v_{i(t-1)} \right) \quad \forall i \in \mathrm{S},\ \forall t \tag{15}$$

$$D_{dt}^{\min} z_{dt} \le D_{dt} \le D_{dt}^{\max} z_{dt} \quad \forall d \in \mathrm{D},\ \forall t \tag{16}$$

$$\sum_{t \in [\alpha_d, \beta_d]} D_{dt} = E_d \quad \forall d \in \mathrm{D} \tag{17}$$

$$T_d^{\mathrm{on}} \ge MU_d \left(z_{dt} - z_{d(t-1)} \right) \quad \forall d \in \mathrm{D},\ \forall t \tag{18}$$

$$\Delta_d = \left(\beta_d^{\mathrm{new}} - \alpha_d^{\mathrm{new}} \right) - \left(\beta_d - \alpha_d \right) \quad \forall d \in \mathrm{D}. \tag{19}$$

Resilient Operation Problem Formulation:

$$\underset{\mathrm{U}}{Max} \underset{\mathrm{P}}{Min} \quad w_s = \sum_t (SL_{1,ts} + SL_{2,ts}) \tag{20}$$

$$\sum_i P_{its} + SL_{1,ts} - SL_{2,ts} = \sum_d D_{dts} \quad \forall t \tag{21}$$

$$I_{its} = \hat{I}_{it} \quad \lambda_{its} \quad \forall i \in \mathrm{G},\ \forall t \tag{22}$$

$$u_{its} = \hat{u}_{it} \quad \mu_{its}^{\mathrm{dch}} \quad \forall i \in \mathrm{S},\ \forall t \tag{23}$$

$$v_{its} = \hat{v}_{it} \quad \mu_{its}^{\mathrm{ch}} \quad \forall i \in \mathrm{S},\ \forall t \tag{24}$$

$$z_{dts} = \hat{z}_{dt} \quad \pi_{dts} \quad \forall d \in \mathrm{D},\ \forall t \tag{25}$$

$$\left| P_{its} - \hat{P}_{it} \right| \le RR \quad \forall i \in \mathrm{G},\ \forall t \tag{26}$$

$$-P_M^{\max} U_{ts} \le P_{M,ts} \le P_M^{\max} U_{ts} \quad \forall t. \tag{27}$$

Subject to (4)–(6), (9), (10), (12), (13), (16), and (17) for each scenario s.

The objective of the normal operation problem is to minimize the microgrid operation cost including the operation cost of dispatchable units, the cost of power transfer from the main grid, and the inconvenience cost realized by consumers (1). The cost of power transfer from the main grid could be positive or negative depending on the direction of flow in the line connecting the microgrid to the main grid. A negative cost, which represents a power export to the main grid, appears as an economic benefit for the microgrid. The inconvenience cost represents the penalty in scheduling adjustable loads outside the time intervals specified by consumers. The constant penalty factor, K_d, is used to prioritize the loads with regards to sensitivity in operating within the specified time intervals, where a higher value for K_d represents a less flexible load in terms of operating time interval adjustments. The value for K_d is selected reasonably higher than the generation cost of units and the market price.

The load balance constraint (2) ensures that the sum of power generated by DERs and power from the main grid would match the hourly load. The power transfer with the main grid is limited by flow limits of the line connecting the microgrid to the main grid (3). The dispatchable unit generation is subject to minimum and maximum generation capacity limits (4), ramp up and ramp down rate limits (5), (6) and minimum up and down time limits (7), (8). The unit commitment state, I_{it}, is one when unit is committed and is zero otherwise. The energy storage power could be positive (discharging), or negative (charging). In either case the energy storage power is limited by minimum and maximum power constraints (9)–(11). The energy storage stored energy is calculated based on the amount of charged/discharged power (12) and restricted with capacity limits (13). Minimum charging and discharging time limits, i.e., the minimum number of consecutive hours that the energy storage must maintain its operational mode, are also considered (14), (15). Adjustable loads are subject to minimum and maximum rated powers (16), and would consume the required energy to complete an operating cycle in the time interval specified by the consumer (17). Certain loads may be subject to minimum operating time (18) which is the number of consecutive hours that a load must consume power once it is switched on. Constraint (19) reflects the change in adjustable loads schedules in the normal operation problem, where $[\alpha_d^{\mathrm{new}}, \beta_d^{\mathrm{new}}]$ represents the new operating time interval, which is ensured to be larger than the initially specified time interval, i.e., $\beta_d^{\mathrm{new}} \geq \beta_d$ and $\alpha_d^{\mathrm{new}} \leq \alpha_d$.

Once the normal operation problem solution is obtained, the resilient operation problem will be solved. The objective of the resilient operation problem for an islanding scenario s is to minimize the power mismatches (20). Power balance equation (21) encompasses slack variables SL_1 and SL_2, which act as virtual generation and virtual load, respectively. A nonzero value for either of these variables denotes a power mismatch in the microgrid resilient operation. The commitment of dispatchable units and the schedule of energy storage and adjustable loads are obtained from the normal operation problem. The given variables are replaced with local variables for obtaining associated dual multipliers (22)–(25), and further forming the resiliency cut. The permissible change in dispatchable unit output from the normal operation to resilient operation is represented by (26).

Uncertainty Consideration:

To capture the load and non-dispatchable generation forecast uncertainties, robust programming is employed in which the worst case solution of the resilient operation problem is to be found over uncertainty set U. To find this robust solution, the objective (20) is maximized over the uncertainty set to find the worst case solution of the mismatch minimization problem. The obtained max-min problem is complex to solve, in which an efficient way to solve is finding the dual problem of the inner minimization problem and combine it with the outer maximization problem. The worst case solution will be obtained at extreme points of uncertain parameters [23], [24]. In the proposed resilient operation problem, however, the extreme points of uncertain parameters, i.e., non-dispatchable generation and load, could be simply obtained. A higher load and a lower non-dispatchable generation will result in a higher mismatch, thus the worst case solution would be obtained when the non-dispatchable generation is at its lower uncertainty bound and the load is at its upper uncertainty bound. The power balance constraint is accordingly replaced with (28), where inserted bars represent the upper bound and the lower bound of the load and non-dispatchable generation forecast uncertainty intervals, respectively,

$$\sum_{i\in \mathrm{G}} P_{it} + \sum_{i\in \mathrm{W}} \underline{P}_{it} + SL_{1,t} - SL_{2,t} = \sum_{d\in \mathrm{D}} D_{dt} + \sum_{d\notin \mathrm{D}} \overline{D}_{dt} \quad \forall t. \tag{28}$$

To capture the uncertainty due to main grid supply interruptions, a binary outage state is included in the main grid power constraint (27), and accordingly, islanding scenarios are defined. A zero value for the outage state would model the microgrid islanding as it imposes a value of zero to the main grid power. Each islanding scenario would start from a different hour and would last for the maximum predicted interruption time. For example, if the incident is predicted to impact the main grid between hours $t+1$ and $t+m$, and the estimated maximum repair and restoration time is T hours, a total of m scenarios will be considered for islanding, and each would last for T hours. The binary outage state in (27) is determined offline based on islanding scenarios. The feasible islanding is examined in all scenarios, and if there is any mismatch, the normal operation problem solution would be revised using the resiliency cut (29). This cut results in a change in the unit commitment states, energy storage schedule, and adjustable loads schedules based on resiliency considerations. The iterative process continues until power mismatches in all islanding scenarios reach zero:

$$\hat{w}_s + \sum_{i\in \mathrm{G}} \lambda_{its}(I_{it} - I_{its}) + \sum_{i\in \mathrm{S}} \mu_{its}^{\mathrm{dch}}(u_{it} - u_{its}) + \sum_{i\in \mathrm{S}} \mu_{its}^{\mathrm{ch}}(v_{it} - v_{its}) + \sum_{i\in \mathrm{D}} \pi_{dts}(z_{dt} - z_{dts}) \leq 0. \tag{29}$$

It is probable that after a certain number of iterations and revising the unit commitment states, energy storage schedule, and adjustable loads schedules, a feasible islanding is not achieved and the power mismatch still persists. The microgrid master control will, therefore, curtail loads. This action is considered as the last resort since it causes a significant inconvenience for microgrid consumers. The microgrid master controller will simply curtail loads, equal to the power mismatch between the available generation and load, to achieve the feasible islanding and ensure resiliency. The curtailment, however, would be performed based on the load criticality, in which more critical loads have a lower priority for curtailment. Once curtailed, the problem is converged and there would be no need to perform further iterations.

IV. NUMERICAL SIMULATIONS

The proposed resiliency-oriented microgrid optimal scheduling model is applied to a test microgrid. The data for generating units, energy storage, and adjustable loads, as well as the forecasted values of microgrid hourly fixed load, non-dispatchable units' generation, and market price are borrowed from [22]. A constant penalty factor of \$100/h, for every hour deviation from adjustable loads specified start and end times, is considered. A 24-h scheduling horizon is considered for studies, assuming that the incident occurs, and the possible damages are repaired, within this horizon. Any other scheduling horizon can be selected based on the microgrid master controller's prediction of the main grid restoration time. Dispatchable units' commitments and energy storage charging/discharging schedules will be determined in the normal operation problem and remain unchanged in the resilient operation problem. It is assumed that microgrid components are not subject to outage during the scheduling horizon. The resiliency-oriented microgrid optimal scheduling is studied considering an uncertain main grid supply interruption, as well as uncertain load and generation forecasts. It is predicted that the incident will result in main grid supply interruption at noon. Based on forecasts, the damage to the main grid will be repaired and the supply will be restored in less than 7 hours from the time of incident. A forecast error of ±20% for non-dispatchable generation and ±10% for load is considered.

Case 1: Impact of Uncertainties on Microgrid Scheduling: The resiliency-oriented microgrid optimal scheduling problem is solved for two cases. In the first case the microgrid master controller assumes that the incident would occur exactly at noon, i.e., the time of incident is known, and then schedules microgrid resources for a 7-hour resilient operation. In the second case, the microgrid master controller considers a two-hour uncertainty in the time of incident, so it would solve the resilient operation problem for five different islanding scenarios, from 10 am to 2 pm, and each lasting for 7 hours. The problem is implemented on a 2.4-GHz personal computer using CPLEX 11.0 [25].

Case 1-a: The resiliency-oriented microgrid optimal scheduling results in a total operation cost of $11855, considering known incident time and duration. In the resiliency mode the power transfer from the main grid is zero, therefore sufficient capacity is committed in the normal operation to enable a quick switching to resilient operation without interruption in load supply. Accordingly, microgrid components are scheduled to be able to supply the load for seven consecutive hours. In the first iteration, the solution of the normal operation problem commits only two dispatchable units 1 and 2, which results in 8.61 MWh power mismatch in resilient operation. However, additional commitment of units 3 and 4, revising the adjustable loads schedules, and revising the energy storage discharging schedule at subsequent iterations, reduces the total mismatch to 3.57 MWh. This mismatch could not be further reduced, thus load is curtailed.

In the obtained solution, dispatchable units 3 and 4 are not economical and are committed due to resiliency considerations; therefore, they would be dispatched at their minimum generation capacities. The energy storage is discharged at a slow rate for 7 hours to cooperate in the microgrid resilient operation when the available unit capacity cannot completely supply the local load. The schedule of adjustable loads is changed, where most of adjustable loads are moved toward end of the day and are partially scheduled in the specified time horizon. These changes result in reduced inconvenience for consumers and also correspond to lower rate hours in normal operation. The obtained solution indicates that by committing additional units, changing the energy storage schedule, and revising adjustable loads schedules, the load curtailments in case of main grid supply interruption and under uncertain load and generation could be significantly reduced.

The sensitivity of the solution with respect to load and non-dispatchable unit generation forecast uncertainties is analyzed and depicted in Figs. 3 and 4, respectively. In Fig. 3, the generation forecast error is fixed at 20% while the load forecast error is changed from zero to 10%. In Fig. 4, the load forecast error is fixed at 10% while the generation forecast error is changed from zero to 20%. The results advocate that the microgrid scheduling solution depends significantly on load forecast errors. By increasing the generation forecast error from zero to 10%, the load curtailment is increased by 0.7 MWh, while the related increase for the load forecast error is more than 3.5 MWh. Furthermore, the load curtailment increases almost linearly by increasing the generation forecast error, while this relationship for increase in the load forecast error is exponential. The result suggests that a more accurate load forecast has a more significant role in the microgrid resilient operation compared to generation forecasts.

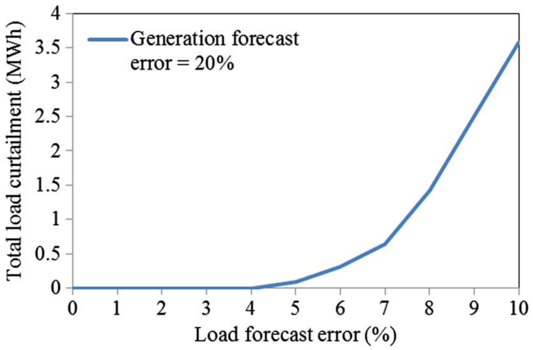

Fig. 3. Total load curtailment as a function of load forecast error.

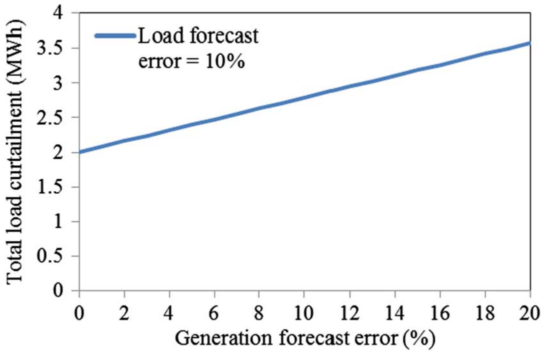

Fig. 4. Total load curtailment as a function of generation forecast error.

Case 1-b: In the second case, the problem is solved for an uncertain start time of the incident. Since the incident is forecasted to occur at noon with a two-hour uncertainty, five scenarios are considered in the resilient operation problem, each lasting for seven hours. Scenarios will consider islanding from hours 10 am, 11 am, 12 pm, 1 pm, and 2 pm, called scenarios 1 to 5. The initial normal operation schedule results in an average of 11.2 MWh mismatch in all scenarios in the first iteration. Forming the resiliency cut, the mismatch will be reduced in subsequent iterations. After six iterations a feasible islanding in scenarios is not guaranteed, while additional units 3 and 4 are committed, and adjustable loads are scheduled outside their specified operating time interval. As a last resort, the microgrid master controller partially curtails loads in each scenario; thus, the load and generation in all scenarios would match. The total generation cost in this case is $12087, which includes generation cost of local DERs, energy purchase from the main grid, and the consumer inconvenience cost. The final solution includes an average of 3.7 MWh load curtailment in scenarios, with the lowest in scenario 1 (i.e., 0.89 MWh) and the highest in scenario 5 (i.e., 6.50 MWh). The higher load curtailment in scenario 5 compared to scenario 1 is due to the reduced available charge of the energy storage at hours 20–21. When reaching these times the energy storage is completely discharged. Moreover, the generation of renewable resources is zero. Thus, the microgrid master controller is required to curtail more loads at these hours to maintain the supply and load balance.

A comparison between these two cases demonstrates that the solution of the second case results in a higher operation cost and inconvenience for consumers as well as a higher expected load curtailment; however, this solution is more resilient than that in the first case. The solution of the second case ensures a robust microgrid operation against uncertain main grid supply interruptions occurred in any of hours between 10 am and 2 pm. To further elaborate the resiliency of the second case solution, assume that the main grid supply is interrupted at hour 10 and will last for 7 hours. In this situation, the solution of the second case would not change as it already considers this interruption and accordingly schedules microgrid resources for resilient operation. However, the solution of the first case would result in significant load curtailments. If scenario 1 occurs, i.e., the interruption starts at hour 10, the microgrid would have to curtail more than 17 MWh to balance load and supply during resilient operation. Bulk of the curtailment occurs at hours 10 and 11, in which the microgrid has not scheduled generation units as well as the energy storage to supply the load in case of islanding. This comparison advocates that considering an uncertain main grid supply interruption time may result in a higher operation cost, but would be more robust compared to the case when this uncertainty is not taken into account.

Solving the optimal microgrid scheduling, without resiliency considerations, the total operating cost is obtained as $11183. It shows that the resiliency-oriented scheduling has resulted in 6% and 8% increase in the total operation cost in the first and second cases, respectively. This cost could be considered as the cost of resiliency, which is added to the microgrid operation cost for guaranteeing a reliable supply of loads during main grid supply interruptions. When compared with the amount of avoided microgrid curtailment, this cost is insignificant, which shows the viability of resiliency-oriented microgrid scheduling.

Case 2: Impact of Permissible Power Adjustment on Microgrid Scheduling: The impact of permissible power adjustment on microgrid scheduling solutions is studied in this case. Uncertainty in load, renewable generation, and main grid supply interruption time and duration is considered as that in Case 1-b. The permissible power adjustment would restrict the change of dispatchable units output when the microgrid switches from normal operation to resilient operation. A higher permissible adjustment provides more flexibility in scheduling for resilient operation, results in less load curtailment, and reduces the operation cost. Results of this analysis, based on operation costs, are depicted in Fig. 5 in which permissible power adjustment is presented as a percentage of associated dispatchable unit ramp rate. A zero permissible power adjustment represents that the dispatchable units output cannot be changed when switching to resilient operation. This task is analogous to considering units power output as a preventive action in dealing with resiliency rather than a corrective action. Although this action is much simpler to schedule and perform than a corrective action, the operation cost will be increased as shown in Fig. 5.

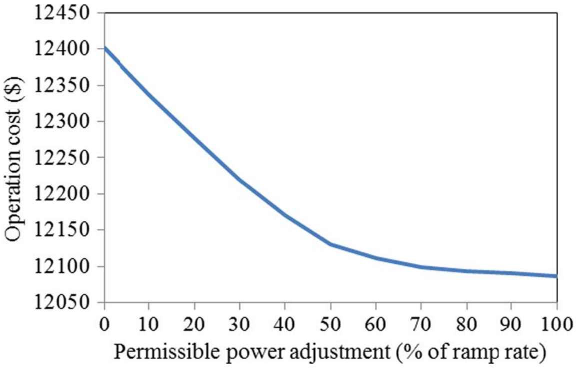

Fig. 5. Microgrid operation cost as a function of permissible power adjustment.

V. DISCUSSIONS

Microgrids are viable technologies for improving power system resiliency by promoting the dispersion of power resources and islanding. An efficient mathematical modeling of the microgrid optimal scheduling problem based on resiliency considerations, however, is required to deliver expected benefits. Specific features of the proposed resiliency-oriented microgrid optimal scheduling model are listed as follows:

- Least cost normal operation: The microgrid optimal scheduling determines the operation of dispatchable units, energy storage, and adjustable loads, along with the main grid power transfer to minimize the cost of supplying local loads in normal power system operation.
- Resiliency consideration: Sufficient DER capacity is scheduled to enable a seamless islanding. If required, adjustable loads schedules are revised and additional loads are curtailed to enable the resilient operation.
- Uncertainty consideration: Forecast errors involved in load and non-dispatchable generation forecasts, as well as uncertain main grid supply interruption time and duration, are captured in the microgrid resilient operation using a robust optimization method and via worst case analysis.
- Consumer convenience: The consumer decisions in scheduling adjustable loads are not changed unless it is required to obtain a feasible islanding solution. The changes, however, are penalized to reduce the inconvenience for consumers and reflect the load schedule outside specified operating time intervals. Furthermore, additional load curtailments are performed based on load criticality as a last resort for removing power mismatches.
- Operational flexibility: The proposed model provides an efficient method for the microgrid master controller on employing the available resources in addressing resiliency needs.

VI. CONCLUSION

A resiliency-oriented microgrid optimal scheduling considering prevailing uncertainties in load, generation, and the main grid supply interruption time and duration, was proposed. A decomposition method was employed to decouple the problem to a normal operation problem (i.e., when main grid could supply the microgrid), and a resilient operation problem (i.e., when the main grid power is not available and the microgrid would switch to the islanded mode). The feasibility of resilient operation was ensured via three actions, which respectively revised the unit commitments and energy storage schedules, revised adjustable loads schedules, and curtailed loads. The required revisions were reflected to the normal operation problem via resiliency cuts. A robust optimization method was employed to find the worst case solution of the resilient operation problem when considering load and generation forecast uncertainties. Main grid supply interruption uncertainty was captured via islanding scenarios. Mixed integer programming was used to model the normal operation problem, and linear programming was used to model the resilient operation problem. Numerical simulations exhibited the economy and resiliency merits of the proposed model.

REFERENCES

[1] A. Flueck and Z. Li, "Destination perfection," *IEEE Power Energy Mag.*, vol. 6, no. 6, pp. 36–47, Nov./Dec. 2008.

[2] M. Shahidehpour and J. Clair, "A functional microgrid for enhancing reliability, sustainability, energy efficiency," *Electricity J.*, pp. 21–28, Oct. 2012.

[3] S. Bahramirad, W. Reder, and A. Khodaei, "Reliability-constrained optimal sizing of energy storage system in a microgrid," *IEEE Trans. Smart Grid*, vol. 3, no. 4, pp. 2056–2062, Dec. 2012.

[4] I. Bae and J. Kim, "Reliability evaluation of customers in a microgrid," *IEEE Trans. Power Syst.*, vol. 23, no. 3, pp. 1416–1422, Aug. 2008.

[5] A. G. Tsikalakis and N. D. Hatziargyriou, "Centralized control for optimizing microgrids," *IEEE Trans. Energy Conv.*, vol. 23, no. 1, pp. 241–248, Mar. 2008.

[6] "Using distributed energy resources, a how-to guide for federal facility managers," Federal Energy Management Program, DOE/GO-102002-1520, U.S. Dept. of Energy, May 2002.

[7] A. Khodaei and M. Shahidehpour, "Microgrid-based co-optimization of generation and transmission planning in power systems," *IEEE Trans. Power Syst.*, vol. 28, no. 2, pp. 1582–1590, May 2013.

[8] S. Chowdhury, S. P. Chowdhury, and P. Crossley, *Microgrids and Active Distribution Networks.*. London, U.K.: IET Renewable Energy Series, 2009.

[9] "Using distributed energy resources, a how-to guide for federal facility managers," Federal Energy Management Program, DOE/GO-102002-1520, U.S. Dept. of Energy, May 2002.

[10] M. Shahidehpour, "Role of smart microgrid in a perfect power system," in *Proc. IEEE Power Energy Soc. Gen. Meeting*, 2010.

[11] V. Meyer, C. Myres, and N. Bakshi, "The vulnerabilities of the power-grid system: Renewable microgrids as an alternative source of energy," *J. Bus. Con. Emer. Plan.*, vol. 4, no. 2, pp. 142–153, 2010.

[12] P. Agrawal, "Overview of DOE microgrid activities," in *Proc. Symp. Microgrid*, Montreal, QC, Canada, Jun. 2006, vol. 23.

[13] A. G. Tsikalakis and N. D. Hatziargyriou, "Operation of microgrids with demand side bidding and continuity of supply for critical loads," *Eur. Trans. Electr. Power*, vol. 21, no. 2, pp. 1238–1254, Mar. 2011.

[14] S. Rahman, "Framework for a resilient and environment-friendly microgrid with demand-side participation," in *Proc. IEEE Power Eng. Soc. Gen. Meeting—Convers. Del. Electr. Energy 21st Century*, 2008.

[15] P. Li, P. Degobert, B. Robyns, and B. Francois, "Implementation of interactivity across a resilient microgrid for power supply and exchange with an active distribution network," *IET Digital Library*.

[16] F. O. Resende, N. J. Gil, and J. A. P. Lopes, "Service restoration on distribution systems using Multi-MicroGrids," *Eur. Trans. Electr. Power*, vol. 21, no. 2, pp. 1327–1342, Mar. 2011.

[17] C. M. Colson, M. H. Nehrir, and R. W. Gunderson, "Distributed multi-agent microgrids: A decentralized approach to resilient power system self-healing," in *Proc. 4th Int. Symp. Resilient Control Syst.*, 2011, pp. 83–88.

[18] J. Hurtt and L. Mili, "Residential microgrid model for disaster recovery operations," in *Proc. IEEE Grenoble Conf.*, 2013, pp. 1–6.

[19] C. Gouveia, J. Moreira, C. L. Moreira, and J. A. Pecas Lopes, "Coordinating storage and demand response for microgrid emergency operation," *IEEE Trans. Smart Grid*, vol. 4, no. 4, pp. 1898–1908, Dec. 2013.

[20] X. Xu, J. Mitra, N. Cai, and L. Mou, "Planning of reliable microgrids in the presence of random and catastrophic events," *Int. Trans. Electr. Energy Syst.*, 2013, doi: 10.1002/etep.1768.

[21] S. Cano-Andrade, M. R. von Spakovsky, A. Fuentes, C. Lo Prete, B. F. Hobbs, and L. Mili, Multi-objective optimization for the sustainable-resilient synthesis/design/operation of a power network coupled to distributed power producers via microgrids vol. 6, Energy, Parts A and B, pp. 1393–1408, 2012.

[22] A. Khodaei, "Microgrid optimal scheduling with multi-period islanding constraints," *IEEE Trans. Power Syst.*, vol. 29, no. 3, pp. 1383–1392, May 2014.

[23] A. Ben-Tal, L. El Ghaoui, and A. Nemirovski*, Robust Optimization*. Princeton, NJ, USA: Princeton Univ. Press, 2009.

[24] A. Thiele, T. Terry, and M. Epelman, "Robust linear optimization with recourse," *Rapport Technique*, pp. 4–37, 2009.

[25] ILOG CPLEX, ILOG CPLEX Homepage 2009, [Online]. Available: http://www.ilog.com

Amin Khodaei (M'11) received the Ph.D. degree in electrical engineering from the Illinois Institute of Technology (IIT), Chicago, IL, USA, in 2010.

He was a visiting faculty (2010–2012) in the Robert W. Galvin Center for Electricity Innovation at IIT. He joined the University of Denver, Denver, CO, USA, in 2013 as an Assistant Professor. His research interests include power system operation, planning, computational economics, and smart electricity grids.