Networked Microgrids for Improving Economics and Resiliency

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***Abstract*—In this paper, we propose networked microgrids to facilitate the integration of variable renewable generation and improve the economics and resiliency of electricity supply in microgrids. A new concept, probability of successful islanding (PSI), is used to quantify the islanding capability of a microgrid considering the uncertainty of renewable energy resources and load, as well as exchanged power at the point of common coupling. With the goal of minimizing the total operating cost while preserving the user-specified PSI, a chance-constrained optimization problem is formulated for the optimal scheduling of both individual microgrids and networked microgrids. Numerical simulation results show significant savings in electricity cost can be achieved by the proposed networked microgrids without compromising grid resiliency. The impact of correlation coefficients among the renewable generation and loads of adjacent microgrids has been studied as well.**

***Index Terms*—Networked microgrids, optimal scheduling, probability of successful islanding, economics, resiliency.**

NOMENCLATURE

The main symbols used in this paper are defined below. Others will be defined as required in the text. A $\triangle$ indicates forecast error for the variable and ˆ indicates the forecast value.

A. Indices

n	Index of microgrids, running from 1 to N_M.
i	Index of dispatchable generators, running from 1 to N_G.
j	Index of demands, running from 1 to N_D.
b	Index of battery storage devices, running from 1 to N_B.
t	Index of time periods, running from 1 to N_T.
m	Index of energy blocks offered by generators, running from 1 to N_I.
l	Index of probability intervals, running from 1 to N_L.

B. Variables

1) Binary Variables:

u_{it}	1 if unit i is scheduled on during period t and 0 otherwise.
u_{bt}^{C}, u_{bt}^{D}	1 if battery b is scheduled charging/discharging during period t and 0 otherwise.
b_{tl}^{U}, b_{tl}^{D}	Binary indicators of probability interval l during period t.

2) Continuous Variables:

$p_{it}\left(m\right)$	Power output scheduled from the m-th block of energy offer by dispatchable unit i during period t . Limited to $p_{it}^{\max}\left(m\right)$.
P_{it}	Power output scheduled from dispatchable unit i during period t.
P_t^{PCC}	Exchanged power at PCC during period t.
$P_{bt}^{\mathrm{C}}, P_{bt}^{\mathrm{D}}$	Charging/discharging power of battery b during period t.
P_{bt}	Output power of battery b during period t.
SOC_{bt}	State of charge of battery b during period t.
R_{it}^{U}, R_{it}^{D}	Up- and down-spinning reserve of unit i during period t.
R_{bt}^{U}, R_{bt}^{D}	Up- and down-spinning reserve of battery b during period t.
PSI_t	Probability of successful islanding during period t.

C. Constants

$\lambda_{it}\left(m\right)$	Marginal cost of the m-th block of energy offer by dispatchable unit i during period t.
C_{bt}	Degradation cost of battery b during period t.
λ_t^{PCC}	Purchasing/selling price of energy from/to distribution grid during period t.
A_i	Operating cost of dispatchable unit i at the point of $P_i^{\min}$.
Q_{it}^{U}, Q_{it}^{D}	Cost of up- and down-spinning reserve of unit i during period t.

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Q^{U}_{bt}, Q^{D}_{bt} Cost of up- and down-spinning reserve of battery b during period t.
$P^{\max}_i, P^{\min}_i$ Maximum/minimum output of DG i.
P^{W}_t, P^{PV}_t Wind turbine/PV power output during period t.
P_{jt} Power consumption scheduled for demand j during period t.
$\triangle N^D_t$ Net demand forecast error of microgrid during period t.
μ_t, σ_t Mean and standard deviation of $\triangle N^D_t$.
$\mathrm{PSI}^{\mathrm{req}}$ PSI requirements of microgrid operators.
$P^{\mathrm{C,max}}_b, P^{\mathrm{D,max}}_b$ Maximum charging/discharging power of battery b.
$SOC^{\max}_{bt}, SOC^{\min}_{bt}$ Maximum/minimum state of charge of battery b during period t.
$\eta^{\mathrm{C}}_b, \eta^D_b$ Battery charging/discharging efficiency factor.
$\triangle t$ Time duration of each period.
τ Amount of time available of DGs and batteries to ramp up/down their output to deliver the reserve.

I. INTRODUCTION

The benefit of using a microgrid for local power reliability during grid outages and emergencies is well known. Networked microgrids, defined as an aggregation of interconnected adjacent microgrids, offer a new, more efficient and resilient alternative to traditional individual microgrids. Because of the benefits they offer, networked microgrids have attracted growing attention in recent years [1]-[5]. Normally, a two-layer energy management strategy is used for networked microgrid scheduling in distribution systems. In the inner layer, each microgrid schedules its own generation resources and loads, while outer layer optimization coordinates the power sharing among all microgrids. From a control perspective, P-Q based primary control with droop characteristics for facilitating energy transactions of the microgrids and maintaining voltage and frequency stability under disturbances is presented in [6].

In the existing literature, research on networked microgrids focuses primarily on optimal energy transaction strategies to meet economic objectives. However, the resiliency of microgrids and networked microgrids is rarely considered as an aspect of optimization. In fact, the most important feature of a microgrid is its ability to separate itself from the distribution utility during outages and continue to supply all or selected critical loads in its own islanded portion. Therefore, the economic benefits of networked microgrids cannot be validated without considering their system resiliency.

In view of the shortcomings of existing networked microgrid scheduling strategies, this paper develops a new scheduling strategy for both networked microgrid and independent microgrid operation considering probabilistic constraints of successful islanding. Considering the uncertainty of renewable generation and power at the point of common coupling (PCC), a new concept— probability of successful islanding (PSI)— is proposed to indicate the probability that a microgrid is maintaining adequate up- and down-spinning reserve to meet local demands and accommodate local renewable generation after instantaneously islanding from the main grid in [7]. The networked microgrids and independent microgrids are scheduled with specified PSI. The main contributions of this study are as follows:

1) Validates the benefit of economics and resiliency of networked microgrids compared with independent microgrids, and
2) Performs a sensitivity analysis to demonstrate the impacts of correlation coefficients among the renewable generation and loads of adjacent microgrids.

This paper is organized as follows. In Section II, a microgrid scheduling strategy with chance-constrained islanding capability is presented. The model is expended to networked microgrids in Section III. A case study and conclusions are provided in Sections IV and V, respectively.

II. MICROGRID SCHEDULING WITH CHANCE-CONSTRAINED ISLANDING CAPABILITY

A. Component Models

The microgrid considered in this paper consists of distributed generators (DGs; e.g., diesel generators, microturbines, and fuel cells), renewable generation (e.g., wind turbines and photovoltaic [PV] panels), energy storage (e.g., battery systems), and local demands. The distributed generators are considered dispatchable units that can be controlled by a microgrid master controller to provide both power and reserve. Depending on the unit type, dispatchable units are subject to various constraints, such as capacity limits, minimum power output limits, ramping rates, and minimum on/off times. In contrast, renewable generators, such as wind turbines and PV panels, are considered nondispatchable units that depend on the meteorological conditions of wind speed, temperature, and solar irradiance. Thus, renewable generation is subject to variability. Extensive research has been done on wind and PV power forecasting [8], [9]. For simplicity, we assume that both wind and PV power forecast error can be modeled as independent, normally distributed random variables [10]. The load forecast error is assumed to follow a normal distribution and to be independent of renewable generation forecasts [11]. Because of the limited sizes of microgrids, relatively large standard deviations are used for both renewable generation and load forecast errors.

B. Problem Formulation

This subsection describes the model of a microgrid scheduling strategy with chance-constrained islanding capability. In the context of microgrids with dispatchable and undispatchable generation and electrical energy storage (e.g., battery) integration, the objective is to minimize the total operating costs—including generation and spinning reserve costs—of local resources as well as the cost of purchasing energy from the main grid. The objective function is shown in Eq. (1). Specifically, the first and second lines are the fuel costs of the DGs (including DG startup costs); the third line is the energy purchasing/selling cost/benefit from the distribution grid; the fourth line is the battery degradation cost; and the fifth and sixth lines are the costs of up- and down-spinning reserve from both DGs and batteries. All terms are in mixed-integer linear form except the DG startup cost (line 2), which can be recast into mixed-integer linear form as in [12].

$$\begin{aligned}\min \quad & \sum_{t=1}^{N_T}\sum_{i=1}^{N_G}\left[\sum_{m=1}^{N_I}\lambda_{it}(m)p_{it}(m)+A_i u_{it}\right] \\ & +\sum_{t=1}^{N_T}\sum_{i=1}^{N_G} SU_{it}\left(u_{it},u_{i,t-1}\right) \\ & +\sum_{t=1}^{N_T}\lambda_t^{\mathrm{PCC}}P_t^{\mathrm{PCC}} \\ & +\sum_{t=1}^{N_T}\sum_{b=1}^{N_B} C_{bt}\left(P_{bt}^{\mathrm{C}}+P_{bt}^{\mathrm{D}}\right) \\ & +\sum_{t=1}^{N_T}\sum_{i=1}^{N_G}\left(Q_{it}^{\mathrm{U}}R_{it}^{\mathrm{U}}+Q_{it}^{\mathrm{D}}R_{it}^{\mathrm{D}}\right) \\ & +\sum_{t=1}^{N_T}\sum_{b=1}^{N_B}\left(Q_{bt}^{\mathrm{U}}R_{bt}^{\mathrm{U}}+Q_{bt}^{\mathrm{D}}R_{bt}^{\mathrm{D}}\right). \end{aligned} \tag{1}$$

The objective function is subject to the following constraints:

$$P_{it}=\sum_{m=1}^{N_I}p_{it}(m)+u_{it}P_i^{\min}\quad \forall i,\forall t \tag{2}$$

$$0\le p_{it}(m)\le p_{it}^{\max}(m)\quad \forall i,\forall t,\forall m \tag{3}$$

$$P_i^{\min}u_{it}\le P_{it}\le P_i^{\max}u_{it}\quad \forall i,\forall t \tag{4}$$

$$R_{it}^{\mathrm{U}}\le P_i^{\max}u_{it}-P_{it}\quad \forall i,\forall t \tag{5}$$

$$R_{it}^{\mathrm{U}}\le u_{it}R_i^{\mathrm{U,max}}\tau\quad \forall i,\forall t \tag{6}$$

$$R_{it}^{\mathrm{D}}\le P_{it}-P_i^{\min}u_{it}\quad \forall i,\forall t \tag{7}$$

$$R_{it}^{\mathrm{D}}\le u_{it}R_i^{\mathrm{D,max}}\tau\quad \forall i,\forall t \tag{8}$$

$$0\le P_{bt}^{\mathrm{C}}\le P_b^{\mathrm{C,max}}u_{bt}^{\mathrm{C}}\quad \forall b,\forall t \tag{9}$$

$$0\le P_{bt}^{\mathrm{D}}\le P_b^{\mathrm{D,max}}u_{bt}^{\mathrm{D}}\quad \forall b,\forall t \tag{10}$$

$$u_{bt}^{\mathrm{C}}+u_{bt}^{\mathrm{D}}\le 1\quad \forall b,\forall t \tag{11}$$

$$SOC_{bt}=SOC_{b,t-1}+P_{bt}^{\mathrm{C}}\eta_b^{\mathrm{C}}\triangle t-P_{bt}^{\mathrm{D}}\frac{1}{\eta_b^{\mathrm{D}}}\triangle t\quad \forall b,\forall t \tag{12}$$

$$SOC_{bt}^{\min}\le SOC_{bt}\le SOC_{bt}^{\max}\quad \forall b,\forall t \tag{13}$$

$$P_{bt}=P_{bt}^{\mathrm{D}}-P_{bt}^{\mathrm{C}}\quad \forall b,\forall t \tag{14}$$

$$R_{bt}^{\mathrm{U}}\le P_b^{\mathrm{D,max}}-P_{bt}\quad \forall b,\forall t \tag{15}$$

$$R_{bt}^{\mathrm{U}}\le \eta_b^{\mathrm{D}}\left(SOC_{bt}-SOC_{bt}^{\min}\right)/\tau\quad \forall b,\forall t \tag{16}$$

$$R_{bt}^{\mathrm{D}}\le P_b^{\mathrm{C,max}}+P_{bt}\quad \forall b,\forall t \tag{17}$$

$$R_{bt}^{\mathrm{D}}\le 1/\eta_b^{\mathrm{C}}\left(SOC_{bt}^{\max}-SOC_{bt}\right)/\tau\quad \forall b,\forall t \tag{18}$$

$$\begin{aligned}&\textstyle\sum_{i=1}^{N_G}P_{it}+\hat{P_t^{\mathrm{W}}}+\hat{P_t^{\mathrm{PV}}}+P_t^{\mathrm{PCC}}+\sum_{b=1}^{N_B}P_{bt}^{\mathrm{D}}\\ &\quad -\textstyle\sum_{b=1}^{N_B}P_{bt}^{\mathrm{C}}=\sum_{j=1}^{N_D}\hat{P_{jt}}\quad \forall t\end{aligned} \tag{19}$$

$$-\sum_{i=1}^{N_G}R_{it}^{\mathrm{D}}-\sum_{b=1}^{N_B}R_{bt}^{\mathrm{D}}\le P_t^{\mathrm{PCC}}+\triangle N_t^D\le\sum_{i=1}^{N_G}R_{it}^{\mathrm{U}}+\sum_{b=1}^{N_B}R_{bt}^{\mathrm{U}}\,\forall t \tag{20}$$

$$\triangle N_t^D=\sum_{j=1}^{N_D}\triangle P_{jt}-\triangle P_t^{\mathrm{W}}-\triangle P_t^{\mathrm{PV}}\quad \forall t \tag{21}$$

For DGs, Eqs. (2) and (3) approximate the production costs of DGs by blocks [13]. Constraint (4) forces the output of DG to be zero if it is not committed. The up-spinning DG reserve is limited by the difference between their maximum capacity and current output in Eq. (5) and its ramping rate in Eq. (6). Similarly, the down-spinning reserve constraints are included in Eqs. (7) and (8). For batteries, Eqs. (9) and (10) are the maximum charging/discharging power of a battery. These two states are mutually exclusive, which is ensured by Eq. (11). The battery state of charge (SOC) is defined by Eq. (12) and the limit of the SOC is enforced by Eq. (13). The output power of a battery is represented in Eq. (14). Similar to the case for DGs, the up-spinning reserve of a battery is constrained by the difference between its current SOC and minimum SOC in Eq. (15) and the difference between its maximum discharging power and current output in Eq. (16). In the same way, the down-spinning reserve constraints of a battery are included in Eqs. (17) and (18). The energy balance is enforced by Eq. (19). The spinning reserve requirement is Eq. (20), which guarantees adequate spinning reserve for successful islanding of the microgrid considering the forecast errors of demand, wind power, and PV power. The net demand forecast error $\triangle N_t^D$ is formulated in Eq. (21). Additionally, each unit or demand is subject to its own operating constraints, such as minimum up/down time, initial condition, and so on. See [14] for details about the formulations of these constraints.

As mentioned in subsection II-A, we assume that wind and PV power forecast error, as well as demand forecast error, can be modeled as independent, normally distributed random variables. Thus, the net demand forecast error $\triangle N_t^D$ also follows normal distribution, i.e., $\triangle N_t^D \sim N\left(\mu_t, \sigma_t^2\right)$. The PSI can be expressed as Eq. (22). The microgrid is considered as successfully islanded if the net demand forecast error $\triangle N_t^D \in \left[-\sum_{i=1}^{N_G}R_{it}^{\mathrm{D}}-\sum_{b=1}^{N_B}R_{bt}^{\mathrm{D}}-P_t^{\mathrm{PCC}},\ \sum_{i=1}^{N_G}R_{it}^{\mathrm{U}}+\sum_{b=1}^{N_B}R_{bt}^{\mathrm{U}} -P_t^{\mathrm{PCC}}\right]$, where $\sum_{i=1}^{N_G}R_{it}^{\mathrm{U}}+\sum_{b=1}^{N_B}R_{bt}^{\mathrm{U}}-P_t^{\mathrm{PCC}}$ stands for the redundant up-spinning reserve after islanding, and $-\sum_{i=1}^{N_G}R_{it}^{\mathrm{D}}-\sum_{b=1}^{N_B}R_{bt}^{\mathrm{D}}-P_t^{\mathrm{PCC}}$ stands for the negative of the redundant down-spinning reserve after islanding. Thus, the PSI can be calculated by integrating the probability distribution curve of $\triangle N_t^D \in \left[-\sum_{i=1}^{N_G}R_{it}^{\mathrm{D}}-\sum_{b=1}^{N_B}R_{bt}^{\mathrm{D}}-P_t^{\mathrm{PCC}},\ \sum_{i=1}^{N_G}R_{it}^{\mathrm{U}}+\sum_{b=1}^{N_B}R_{bt}^{\mathrm{U}} -P_t^{\mathrm{PCC}}\right]$, for each time interval t.

$$\begin{aligned}\mathrm{PSI}_t \;=\; & \mathrm{P}\left(-\sum_{i=1}^{N_G}R_{it}^{\mathrm{D}}-\sum_{b=1}^{N_B}R_{bt}^{\mathrm{D}}-P_t^{\mathrm{PCC}}\le\triangle N_t^D\right.\\ & \left.\le\sum_{i=1}^{N_G}R_{it}^{\mathrm{U}}+\sum_{b=1}^{N_B}R_{bt}^{\mathrm{U}}-P_t^{\mathrm{PCC}}\right).\end{aligned} \tag{22}$$

The formulation of PSI considers probability distributions of forecast errors of wind, PV, and loads. A multi-interval approximation of PSI is proposed in [7], which reformulates PSI into a mixed-integer format. Thus, the chance-constrained programming model for microgrid scheduling could be solved

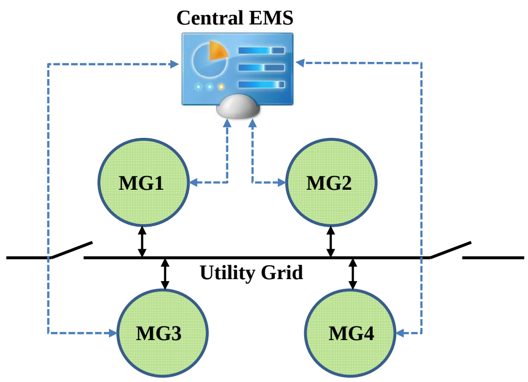

Fig. 1: Example of networked microgrids

by mixed-integer linear programming. Finally, optimal microgrid scheduling with chance-constrained islanding capability can be formulated by substituting Eqs. (20) and (21) with the linearized format of Eqs. (22) and (23).

$$\mathrm{PSI}_t \geq \mathrm{PSI}^{\mathrm{req}} \quad \forall t \tag{23}$$

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The proposed chance-constrained programming model explicitly guarantees that the microgrid has adequate flexibility to meet local demand and accommodate local renewable generation after instantaneously islanding from the main grid with a certain probability specified by the microgrid operator. Thus, the resiliency of the electricity supply of the microgrid is clearly defined.

III. Networked Microgrid Scheduling with Chance-Constrained Islanding Capability

Traditionally, each microgrid is an autonomous entity and schedules its own generation resources and loads to maximize its own benefit. When the utility grid is faulted, each microgrid will be disconnected and will perform as an autonomous island. Although multiple microgrids may be physically connected, the scheduling of the various microgrids is completely independent. On the other hand, interconnected adjacent microgrids can be aggregated or networked at the control and communication layer. An example of a set of four networked microgrids is shown in Fig. 1. In grid-connected mode, the central emergency management system will schedule the four microgrids as a whole. When the upstream utility grid is faulted, the two switches will be opened and the four microgrids will form a single island. Networking the adjacent microgrids is expected to result in better economics and resiliency compared with four independent microgrids.

In this section, we expand the resiliency-constrained scheduling model of a single microgrid proposed in Section II to the case of networked microgrids. First, we need to substitute P_t^{PCC} with the summation of PCC power for all microgrids, i.e., $\sum_{n=1}^{N_M} P_{nt}^{\mathrm{PCC}}$, where $P_{nt}^{\mathrm{PCC}}$is the exchanged power at the PCC for microgrid n at time t. Second, we need to formulate the PSI of the networked microgrids, As a precondition, the probability distribution of the net demand forecast error $\triangle N_t^D$ needs to be calculated. Just as in the previous section, we assume both wind and PV power forecast error and demand forecast error in a microgrid can be modeled as independent, normally distributed random variables with zero mean. Because of the geographic proximity of networked microgrids, the wind power forecast errors of any two microgrids are correlated. Taking a networked microgrid consisting of three microgrids, for example, the mean of the total wind power forecast error is zero, and the deviation of the total wind power forecast error can be calculated according to Eq. (24), where σ_n^w is the standard deviation of wind power forecast error in microgrid n and $\rho_{nn'}^w$ is the correlation coefficient between the wind power forecast errors of microgrids n and n'.

$$(\sigma^w)^2 = \begin{bmatrix} \sigma_1^w \\ \sigma_2^w \\ \sigma_3^w \end{bmatrix}^{\mathrm{T}} \begin{bmatrix} 1 & \rho_{12}^w & \rho_{13}^w \\ \rho_{21}^w & 1 & \rho_{23}^w \\ \rho_{31}^w & \rho_{32}^w & 1 \end{bmatrix} \begin{bmatrix} \sigma_1^w \\ \sigma_2^w \\ \sigma_3^w \end{bmatrix}. \tag{24}$$

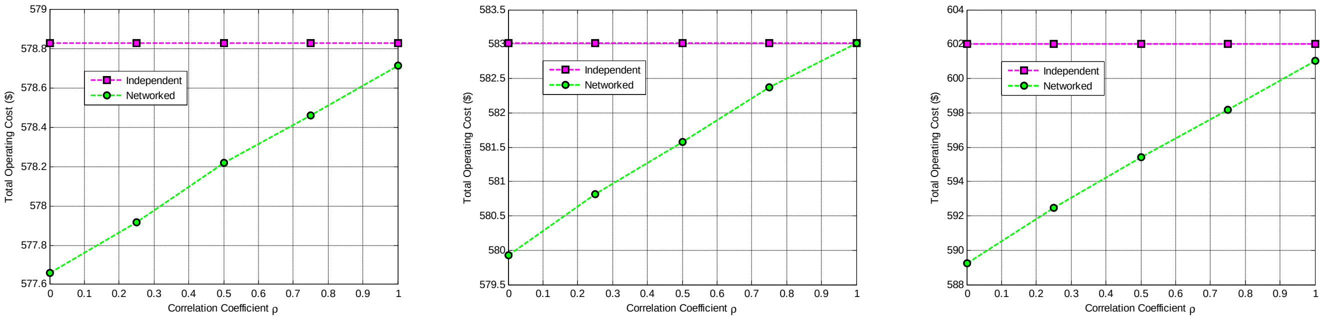
The standard deviation of the total PV power forecast error and total demand forecast error can be calculated similarly. Since the wind and PV power forecast, as well as the demand forecast, are independent, the total net demand forecast error of the networked microgrids $\triangle N_t^D$ follows a normal distribution, i.e., $\triangle N_t^D \sim N\left(\mu_t, \sigma_t^2\right)$, where σ_t^2can be easily calculated based on the result of Eq. (24). With these two modifications, the resiliency-constrained scheduling model of a single microgrid is adapted to handle the resiliency-constrained scheduling of a set of networked microgrids.

IV. Case Studies

To test the proposed networked microgrid scheduling strategy with chance-constrained islanding capability, we built a test system. Three modified microgrids at Oak Ridge National Laboratory's Distributed Energy Control and Communication (DECC) laboratory were connected on the same bus as in Fig. 1. The three microgrids were identical. All parameters for generators, forecast wind power, PV power, and demand, as well as the day-ahead market prices, can be found in [7]. The forecast errors of wind power and PV power were assumed to be a Gaussian distribution with zero mean and a 15% standard deviation. The demand forecast error was assumed to be a Gaussian distribution with zero mean and a 3% standard deviation. The analysis was conducted over a 24-hour scheduling horizon, and each time interval was set at 1 hour. All numerical simulations were coded in MATLAB and solved using the MILP solver CPLEX 12.2. With a prespecified duality gap of 0.1%, the running time of each case was less than 10 seconds on a 2.66 GHz Windows-based PC with 4 GB of RAM.

A. Comparing the Costs of Networked Microgrids and Independent Microgrids at the Same PSI

To show the benefit of networked microgrids, the total operating costs of a networked set of microgrids and of independent microgrids under the same resiliency requirements,



(a) $\mathrm{PSI^{req}} = 0.6$ (b) $\mathrm{PSI^{req}} = 0.8$ (c) $\mathrm{PSI^{req}} = 0.997$

Fig. 2: Comparison of costs of networked and independent microgrids

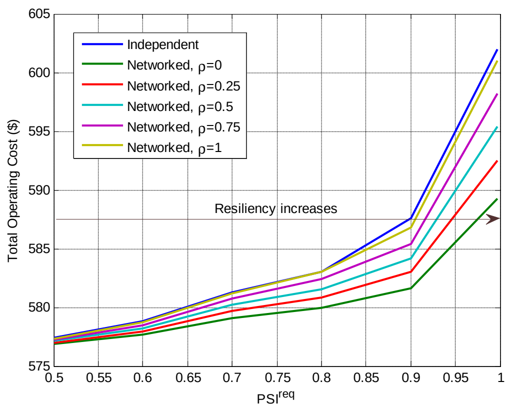


Fig. 3: Comparison of costs of networked and independent microgrids with different levels of PSI requirements

$\mathrm{PSI^{req}}$ are compared in Fig. 2. As can be seen, the operating costs of the networked microgrids are always lower than those of the independent microgrids under the same resiliency requirements. As the resiliency requirement $\mathrm{PSI^{req}}$ increases, the economic benefit of the networked microgrids becomes more significant. The economic benefit of the networked microgrids decreases as the microgrids become more correlated, i.e., the correlation coefficients between the different microgrids increase. Nevertheless, the economic benefit of a networked microgrid is validated.

B. Comparing the PSI of Networked Microgrids and Independent Microgrids at the Same Cost

To show the benefit of networked microgrids in improving system resiliency, the costs of networked and independent microgrids with different levels of PSI requirements are compared in Fig. 3. As can be seen, at the same operating cost, the networked microgrids always have a higher resiliency. This effect is much more obvious when the microgrids are less correlated. This result clearly validates the resiliency benefit of networked microgrids.

V. Conclusions

In this study, we modified the resiliency-constrained scheduling model of a single microgrid to handle the case of a set of networked microgrids. The model explicitly defines the resiliency of a single microgrid and a set of networked microgrids considering their islanding situations and forecast uncertainties. Numerical simulations validated the benefits of networked microgrids, compared with independent microgrids, in terms of of economics and resiliency . In addition, the impacts of correlation coefficients among the renewable generation and loads of adjacent microgrids were studied.

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