Microgrid-Based Co-Optimization of Generation and Transmission Planning in Power Systems

Amin Khodaei, *Member, IEEE*, and Mohammad Shahidehpour, *Fellow, IEEE*

***Abstract*—This paper presents an algorithm for the microgrid planning as an alternative to the co-optimization of generation and transmission expansion planning in electric power systems. The integration of microgrids in distribution systems will offer a decentralized control of local resources for satisfying the network reliability and the power quality required by local loads. The objective in this paper is to minimize the total system planning cost comprising investment and operation costs of local microgrids, the co-optimized planning of large generating units and transmission lines, and the expected cost of unserved energy. The cost of unserved energy reflects the cost of load shedding which is added to the objective function for reliability considerations. The microgrid-based co-optimization planning problem is decomposed into a planning problem and annual reliability subproblem. The optimal integer planning decisions calculated in the planning problem will be examined against the system reliability limits in the subproblem and the planning decisions will be revised using proper feasibility cuts if the annual reliability limits are violated. Numerical simulations demonstrate the effectiveness of the proposed microgrid-based co-optimization planning in power systems and explore the economic and reliability merits of microgrid planning as compared to grid-based generation and transmission upgrades.**

***Index Terms*—Annual reliability, co-optimization of transmission and generation planning, microgrids, power system expansion planning.**

NOMENCLATURE

Indices:

b	Index for load blocks.
h	Index for periods.
i	Index for generating units.
l	Index for transmission lines.
m	Index for buses.
q	Index for microgrids.
s	Superscript for scenarios.
t	Index for years.
$\wedge$	Index for calculated variables.

Sets:

CG	Set of candidate generating units.
CL	Set of candidate transmission lines.
EG	Set of existing generating units.
EL	Set of existing transmission lines.
N_m	Set of components connected to bus m.

Parameters:

B	Bus-line incidence matrix.
CC	Capital cost.
d	Discount rate.
D	HV bus load demand.
DT	Duration time.
M	Large positive constant.
NQ	Maximum number of microgrid installations.
PD	Microgrid load demand.
pr	Probability.
T	Number of years in the planning horizon.
T^{com}	Commissioning year.
UX	Contingency state of generating units.
UY	Contingency state of transmission lines.
$VOLL$	Value of lost load.
x	Reactance of line.
κ	Coefficient of present-worth value.
γ	Salvage factor.

Variables:

C	Total investment and operation cost.
CR	Cost of unserved energy.
$EENS$	Expected energy not served.
LS	Load shedding.
OC	Operation cost.
P	Unit generation.
PL	Line flow.
PM	Microgrid local generation.
u	Microgrid investment state.
y	Line investment state.
z	Unit investment state.
ω	System load curtailment.
θ	Voltage angle.
λ, μ, π	Dual variables.

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A. Khodaei is with the Department of Electrical and Computer Engineering, University of Houston, Houston, TX 77004 USA (e-mail: akhodaei@central.uh.edu).

M. Shahidehpour is with the Robert W. Galvin Center for Electricity Innovation, Illinois Institute of Technology, Chicago, IL 60616 USA (e-mail: ms@iit.edu).

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I. Introduction

MICROGRIDS generate, distribute and regulate the flow of electricity to local customers, representing a modern small-scale power system with a high degree of flexibility and efficiency in both supply and demand sectors [1]–[5]. Technically, a microgrid is a system with at least one distributed energy resource (DER) and one demand which can be islanded from the main power distribution system. In practice, microgrids are introduced to address the emergence of a large number of DERs in distribution systems and to ensure secure and optimal operations of potentially islanded power grids.

A microgrid is considered as a controllable aggregated load from a utility's point of view. The hourly operation of a microgrid is controlled by the microgrid master controller instead of a central dispatch provided by the utility. The DERs located within a microgrid differ from conventional power plants as they possess a smaller capacity, are directly connected to the microgrid distribution network, and could be customized to supply local load requirements [6].

The benefits of a microgrid include the improved reliability by introducing self-healing at the local distribution network, higher power quality by managing local loads, reduction in carbon emission by the diversification of energy sources, economic operation by reducing T&D costs, utilization of less costly renewable energy sources, and offering energy efficiency by responding to real-time market prices [7]–[10].

The salient feature of a microgrid is its ability to be islanded from the main grid by upstream switches at the point of common coupling (PCC). Islanding could be introduced for economic as well as reliability purposes. During main grid disturbances, microgrid is transferred from the grid-connected to the islanded mode and a reliable and uninterrupted supply of consumer loads is offered by local generation resources. The microgrid master controller would offer the optimal operation by maintaining the frequency and voltages within permissible ranges. The islanded microgrid would be resynchronized with the main grid once the disturbance is removed [11]–[13].

Microgrid alternatives to the traditional T&D expansion could reduce the total planning cost and increase the system reliability with a local control option for lowering the possibility of load shedding. Microgrids offer a lower construction time and are regarded as viable options for reducing the transmission congestion when large investments on new generation and transmission facilities are not forthcoming [14]–[18].

Previous power system planning studies investigated generation and transmission expansion planning methodologies in a vertically integrated power system (where a centralized generation and transmission expansion is performed), and a market-based environment (where proposed generation and transmission expansion planning options are coordinated) [19]–[29]. However, existing planning approaches did not consider the impact of microgrid installations on the power system expansion.

This paper utilizes a co-optimization approach to the generation and transmission expansion planning which also considers the most suitable locations for microgrid installations in a power system. The proposed approach considers short-term operation constraints in conjunction with the co-optimization planning of generation and transmission. The proposed microgrid-based co-optimization approach will simulate the iterative and the interactive planning coordination among generation companies, transmission companies, and the ISO in a competitive electricity market.

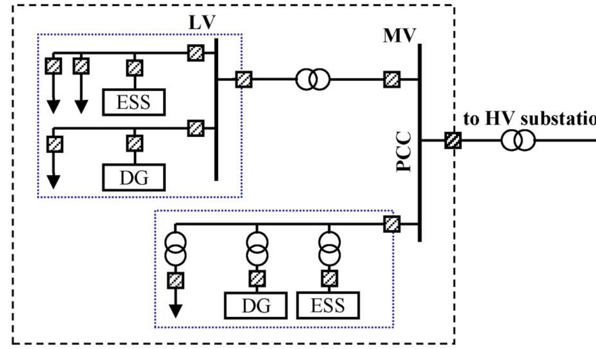

Fig. 1. Typical microgrid architecture (DG: distributed generation, ESS: energy storage system, PCC: point of common coupling).

The proposed microgrid-based co-optimization planning is a mixed-integer programming (MIP) problem. The optimal cost of reliability is considered as an objective and the acceptable reliability level is modeled as a constraint. The Monte Carlo simulation is applied to simulate random component outages and a scenario reduction method is applied as a tradeoff between the computation time and the solution accuracy. The random outages of system components are considered in the calculation of annual expected energy not supplied (EENS).

The rest of the paper is organized as follows. Section II discusses the microgrid architecture and introduces microgrid components. Section III proposes the microgrid-based planning model, while Section IV presents the problem formulation. Section V presents illustrative examples to show the proposed model applied to a standard power system. Discussion on the features of the proposed model and concluding remarks are provided in Sections VI and VII, respectively.

II. Microgrid Model

Fig. 1 depicts a typical microgrid configuration, where DERs are connected to loads through low voltage (LV) and medium voltage (MV) distribution networks. The PCC circuit breaker enables the microgrid islanding. The integration of DERs facilitates bidirectional electricity flows in the distribution network.

The microgrids could be interconnected to form a cluster of microgrids. In this fashion, the loads in each microgrid would be supplied from several interconnected microgrids using a common distribution network. The interconnected microgrids would achieve greater stability and controllability as well as enhanced redundancy to ensure the supply reliability. The interconnection of microgrids significantly reduces the complexity in the control and operation of hundreds of individual DERs. DERs would seamlessly control power and provide required energy to local loads in the interconnection. We assume that DERs and loads are coordinated such that the microgrid generation is used solely to satisfy the interconnected microgrid loads or stored in the energy storage system. DERs in a microgrid are not designed

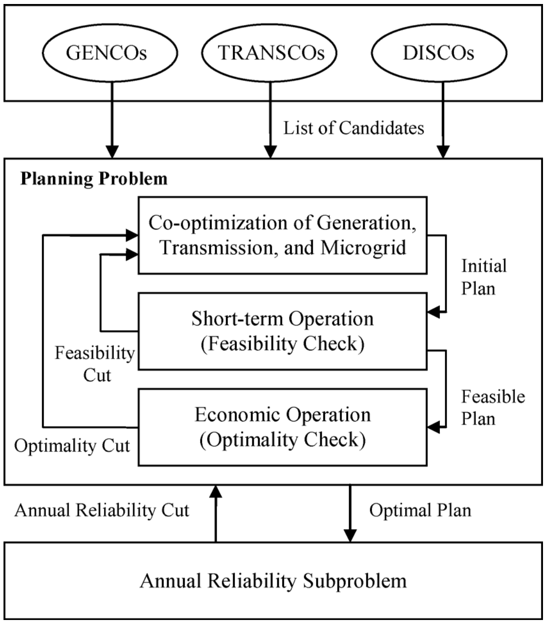

Fig. 2. Proposed microgrid-based co-optimization planning model.

to continuously generate power for supplying the main grid. By allowing such power transfers, the power system could further rely on the DER generation in lieu of large generation expansion planning. Thus, microgrids are regarded as controllable loads in this study and no power generation is injected to the main grid from the interconnected microgrids. A microgrid may include several DERs with variable generation profiles; however, in this study, we assume DERs are aggregated in a cluster of microgrids for supplying local loads in which a microgrid is regarded a controllable load with a more settled hourly profile from the ISO's point of view. The intermittency of DERs inside a microgrid would require additional scenario generation to model DER operation. We assume the distribution network expansion is internalized as part of the microgrid cluster which would not be the ISO's concern.

III. Proposed Microgrid-Based Planning Model

Fig. 2 depicts the proposed microgrid-based planning model. We assume candidate microgrids installed at designated buses would normally be operated in a grid-connected mode. In the case of a main grid disturbance, however, the microgrid would switch over to an islanded mode to satisfy local loads. The investments are analyzed on an annual basis. A year is decomposed into multiple periods and the load duration curve (LDC) is utilized with load blocks at each period. The number and the duration of load blocks are considered as a tradeoff between the accuracy and the computation burden in the proposed planning model. The load forecast at every block in every period of the planning horizon is met by system operation and expansion planning decisions.

The planning problem in Fig. 2 co-optimizes the least-cost options of candidate generating units, transmission lines, and microgrids for supplying the load forecast and satisfying prevailing operation and planning constraints. The objective comprises investment costs and salvage values for new resources, operation costs of generating units and microgrids, and the cost of unserved energy.

A decomposition is applied in Fig. 2 to coordinate the operation and planning constraints as part of the co-optimization scheme. The decomposition would separate the planning problem into a co-optimization of generation, transmission and microgrid, a short-term operation subproblem (which checks the transmission network constraints in the proposed plan) and an economic operation subproblem (which finds the optimal system operation based on the proposed plan). If the feasibility or the optimality check fails, proper cuts are generated in the corresponding subproblems and added to the next iteration of co-optimization of generation, transmission and microgrid. This iterative process will continue until a secure and optimal expansion planning solution is achieved.

IV. Microgrid-Based Planning Problem Formulation

A. Planning Problem

The objective of the proposed microgrid-based planning problem is to minimize the total planning cost throughout the planning horizon as shown in (1):

$$\text{Min} \sum_t \sum_i \kappa_t C_{it} + \sum_t \sum_l \kappa_t C_{lt} + \sum_t \sum_m \sum_q \kappa_t C_{qmt} + \sum_t \kappa_t CR_t. \quad (1)$$

Here, $\kappa_t = 1/(1+d)^{t-1}$ is the present-worth value coefficient. The objective includes investment and operation costs associated with new generating units, transmission lines, and microgrids, in addition to the cost of unserved energy. The objective is evaluated in terms of discounted costs, where discount rates are incorporated in the present-worth cost components. A higher discount rate would affect investments as candidates with higher investment costs become inferior. The cost of unserved energy in the objective would represent the economics of system reliability.

Equations (2)–(5) define cost terms used in the objective function. The generation costs (2) include the investment cost of new generating units and the operation cost of existing and installed units. The operation cost includes fuel and maintenance costs. The investment cost of new transmission lines is represented by (3). The salvage value, i.e., the percentage of depreciation of the initial investment, is included in the investment cost to represent the monetary value of the installed resource at the end of the planning horizon. κ_T is the worth value coefficient of the resources at the end of the planning horizon:

$$\begin{aligned} C_{it} &= CC_i P_i^{\max}(z_{it} - z_{i(t-1)}) \\ &\quad - \frac{\kappa_T}{\kappa_t}\gamma_{it} CC_i P_i^{\max}(z_{it} - z_{i(t-1)}) \\ &\quad + \sum_h \sum_b DT_{bht} OC_i P_{ibht} \end{aligned} \quad (2)$$

$$\begin{aligned} C_{lt} &= CC_l \mathrm{PL}_l^{\max}(y_{lt} - y_{l(t-1)}) \\ &\quad - \frac{\kappa_T}{\kappa_t}\gamma_{lt} CC_l PL_l^{\max}(y_{lt} - y_{l(t-1)}) \end{aligned} \quad (3)$$

$$\begin{aligned} C_{qmt} = &CC_{qm}\left(PM_{qmt}^{\max}u_{qmt} - PM_{qm(t-1)}^{\max}u_{qm(t-1)}\right)\\ &-\frac{\kappa_T}{\kappa_t}\gamma_{qmt}CC_{qm}\left(PM_{qmt}^{\max}u_{qmt}\right.\\ &\left.-PM_{qm(t-1)}^{\max}u_{qm(t-1)}\right)\\ &+\sum_h\sum_b DT_{bht}OC_{qm}PM_{qmbht} \end{aligned} \tag{4}$$

$$CR_t = VOLL_t EENS_t. \tag{5}$$

The candidate generating units and transmission lines will be commissioned once the planning, the detailed engineering design, and the construction work are completed. The commissioning time is dependent on the type and the size of the unit (6)–(7). Once a candidate generating unit or transmission line is installed, its investment state will be fixed at 1 for the remaining years in the planning horizon (8)–(9):

$$z_{it} = 0 \quad \forall i \in \mathrm{CG}, \quad \forall t < T_i^{\mathrm{com}} \tag{6}$$

$$y_{lt} = 0 \quad \forall l \in \mathrm{CL}, \quad \forall t < T_l^{\mathrm{com}} \tag{7}$$

$$z_{i(t-1)} \le z_{it} \quad \forall i \in \mathrm{CG}, \quad \forall t \tag{8}$$

$$y_{l(t-1)} \le y_{lt} \quad \forall l \in \mathrm{CL}, \quad \forall t. \tag{9}$$

The investment and operation costs of a microgrid would depend on the size and the type of DERs used in the microgrid. The microgrid investment cost is assumed to be a linear function of its generation capacity. The operation cost is obtained based on the microgrid generation dispatch. The total planning cost of the microgrid is the sum of its investment and operation costs minus its salvage value (4).

The bus load supply is limited to the associated microgrid generation capacity (10)–(11). The microgrid would shift seamlessly from grid-connected to the islanded mode for supplying local loads. The microgrid generation (12) would either supply loads at associated microgrids or be stored at local storage facilities (rather than feeding the main grid loads). A microgrid could be subject to further expansion (13) to supply the local load forecast. Microgrids are interconnected to form a cluster so that the required reserve in one microgrid could be supplied by the interconnected microgrids where DERs would seamlessly provide the required energy to local loads in the interconnection. In a case that a microgrid is not interconnected to other microgrids, (10) would be modified to increase the installed capacity and further consider the required spinning reserve:

$$PM_{qmt}^{\max} = \operatorname*{Max}_{h,b}\{PD_{qmbht}\} \quad \forall q, \forall m, \forall t \tag{10}$$

$$PM_{qmbht} \le PM_{qmt}^{\max}u_{qmt} \quad \forall q, \forall m, \forall b, \forall h, \forall t \tag{11}$$

$$\sum_q (PM_{qmbht} - PD_{qmbht}) \le 0 \quad \forall m, \forall b, \forall h, \forall t \tag{12}$$

$$u_{qm(t-1)} \le u_{qmt} \quad \forall q, \forall m, \forall t. \tag{13}$$

The cost of unserved energy defined by (5) is obtained based on EENS and the value of lost load (VOLL). EENS is calculated in the subproblem and added in each iteration to the planning problem. The EENS in the first iteration is the base case system reliability. VOLL, which is the load shedding price for compensating customers, depends on several factors including the types of customers, the amount and the duration of load interruption, and the time of outage. A higher VOLL corresponds to lower load shedding [30], [31]. VOLL is given as an input to our model.

The proposed co-optimization expansion planning objective is subject to prevailing operation constraints, such as the limits on generation, fuel, ramping, emission, etc., and transmission network constraints [32], [33]. A dc power flow is used, where it is assumed that the voltage related concerns would be handled by the microgrid master controller. Additional details on the decomposition of the planning problem are found in [34]–[37].

B. Role of Annual Reliability

Once the optimal planning decisions for microgrids and the main grid are made in the planning problem, the new system topology is sent to the subproblems to calculate the annual EENS. The annual reliability calculation at load block b, period h, year t and scenario s is formulated in (14)–(28).

The objective (14) is to minimize the load curtailment for balancing purposes in the case of system component outages [38]. Equation (15) defines the load balance at each system bus incorporating load shedding variable. The dual variables are obtained in (16)–(18) to represent the incremental reduction in load curtailments with regards to system investments. The dual variables are used to generate investment signals for consequent iterations of the planning problem. The existing and candidate generating unit capacity limits are defined by (19)–(20), respectively. Constraints on existing transmission lines are imposed by (21)–(22), while those of candidate transmission lines are (23)–(24). The microgrid generation is limited by (25), while that of a cluster of microgrids in limited by (26). Load shedding is limited by (27). The phase angle of the reference bus is set to zero by (28):

$$\mathrm{Min}\ \omega_{bht}^s = \sum_m (LS_{mbht}^s) \tag{14}$$

$$\begin{aligned} &\sum_{i\in N_m} P_{ibht}^s + \sum_{l\in N_m} PL_{lbht}^s + \sum_q PM_{qmbht}^s + LS_{mbht}^s\\ &\quad = D_{mbht} \quad \forall m \end{aligned} \tag{15}$$

$$z_{it} = \hat{z}_{it} \leftrightarrow \lambda_{it}^s \quad \forall i \in \mathrm{CG} \tag{16}$$

$$y_{lt} = \hat{y}_{lt} \leftrightarrow \mu_{lt}^s \quad \forall l \in \mathrm{CL} \tag{17}$$

$$u_{qmt} = \hat{u}_{qmt} \leftrightarrow \pi_{qmt}^s \quad \forall q \tag{18}$$

$$0 \le P_{ibht}^s \le P_i^{\max} UX_{ibht}^s \quad \forall i \in \mathrm{EG} \tag{19}$$

$$0 \le P_{ibht}^s \le P_i^{\max} UX_{ibht}^s z_{it} \quad \forall i \in \mathrm{CG} \tag{20}$$

$$\begin{aligned} &\left| PL_{lbht}^s - \sum_m B_{l,m}\theta_{mbht}^s \Big/ x_l \right|\\ &\quad \le M(1 - UY_{lbht}^s) \quad \forall l \in \mathrm{EL} \end{aligned} \tag{21}$$

$$|PL_{lbht}^s| \le \mathrm{PL}_l^{\max} UY_{lbht}^s \quad \forall l \in \mathrm{EL} \tag{22}$$

$$\begin{aligned} &\left| PL_{lbht}^s - \sum_m B_{l,m}\theta_{mbht}^s \Big/ x_l \right|\\ &\quad \le M(1 - UY_{lbht}^s) + M(1 - y_{lt}) \qquad \forall l \in \mathrm{CL} \end{aligned} \tag{23}$$

$$|PL_{lbht}^s| \le PL_l^{\max} UY_{lbht}^s y_{lt} \quad \forall l \in \mathrm{CL} \tag{24}$$

$$0 \le PM_{qmbht}^s \le PM_{qmt}^{\max} u_{qmt} \quad \forall q \tag{25}$$

$$\sum_q \left(PM_{qmbht}^s - PD_{qmbht}^s\right) \le 0 \quad \forall m \tag{26}$$

$$0 \le LS^s_{mbht} \le PD_{mbht} \quad \forall m \tag{27}$$

$$\theta^s_{mbht} = 0 \quad m = \text{Ref.} \tag{28}$$

In the above formulation, the constraints on candidate generating unit, transmission line, and microgrids include the associated binary variables determined in the planning problem. The contingency state of generating units and transmission lines are included in the set of constraints. The Monte Carlo simulation is applied to model the random outages of generating units and transmission lines [39], [40]. Moreover, a scenario reduction method is adopted as a tradeoff between the computational burden and the modeling accuracy. An outage in a microgrid will be compensated by adjacent microgrids rather than the main grid. The annual EENS for a system of microgrids is calculated as

$$EENS_t = \sum_h \sum_b \sum_s pr^s DT_{bht} \omega^s_{bht} \quad \forall t. \tag{29}$$

If the EENS limit is violated, reliability constraints (30)–(31) are generated and added to the planning problem for promoting investments on new generating units, transmission lines, and microgrids.

$$\begin{aligned} EENS_t = &\sum_h \sum_b \sum_s pr^s DT_{bht} \omega^s_{bht} \\ &+ \sum_s \sum_{i \in \mathrm{CG}} pr^s \lambda^s_{it} (z_{it} - \hat{z}_{it}) \\ &+ \sum_s \sum_{l \in \mathrm{CL}} pr^s \mu^s_{lt} (y_{lt} - \hat{y}_{lt}) \\ &+ \sum_s \sum_q \sum_m pr^s \pi^s_{qmt} (u_{qmt} - \hat{u}_{qmt}) \ \forall t \end{aligned} \tag{30}$$

$$EENS_t \le EENS_t^{\text{target}} \quad \forall t \tag{31}$$

where λ, μ, and π are dual values of constraints (16)–(18), respectively. In addition, the reliability constraints facilitate the calculation of cost of unserved energy in the planning problem. The iterative procedure will continue until an optimal plan is calculated.

V. Numerical Simulations of the Planning Problem

A modified IEEE 118-bus system is used to demonstrate the application of the proposed model for microgrid-based co-optimization of generation and transmission planning. The system has 118 buses, 54 units, and 186 branches. The data are given in motor.ece.iit.edu/data/MicrogridPlanning.xls. A set of 16 candidate generating units and 8 candidate transmission lines are considered. Forced outage rates of generating units and transmission lines are 4% and 1%, respectively. A 20-year planning horizon is considered. Each planning year is divided into 12 monthly periods. The monthly load is divided into three load blocks representing off-peak, intermediate and peak loads. The quantity and the duration of load blocks may vary in each period within each year. The planning is performed annually while the operation is carried out for each load block. The VOLL is \$10/kWh and the discount rate is 5%.

There are no limitations on annual investments or the number of microgrids, generating units or transmission lines that could be installed annually. The initial system peak load is 5400 MW

TABLE I
Annual Peak Load Forecast

Year	1	2	3	4	5
Peak Load (MW)	4000	4116	4235	4385	4485
Year	6	7	8	9	10
Peak Load (MW)	4615	4748	4886	5028	5174
Year	11	12	13	14	15
Peak Load (MW)	5324	5478	5637	5800	5969
Year	16	17	18	19	20
Peak Load (MW)	6142	6320	6503	6692	6886

TABLE II
Annual EENS Limit

Year	1	2	3	4	5
EENS (MWh)	150.00	154.35	158.83	163.43	168.17
Year	6	7	8	9	10
EENS (MWh)	173.05	178.07	183.23	188.54	194.01
Year	11	12	13	14	15
EENS (MWh)	199.64	205.43	211.39	217.52	223.82
Year	16	17	18	19	20
EENS (MWh)	230.31	236.99	243.87	250.94	258.22

TABLE III
Probabilities of Scenarios After Scenario Reduction

Scenario	1	2	3	4	5	6
Probability	0.6103	0.0330	0.0273	0.0317	0.0497	0.0357
Scenario	7	8	9	10	11	12
Probability	0.0293	0.0250	0.0383	0.0347	0.0430	0.0420

with an annual load growth rate of 2.9%. Table I shows annual peak load forecasts. The initial available generation capacity is 5850 MW. The EENS limit of 150 MWh is considered for the first planning year. The EENS limit is increased 2.9% annually as shown in Table II. The total EENS for the entire planning horizon is limited to 3990 MWh.

We assume microgrids can be installed at any system buses with an investment cost of \$2000/kW and operation cost of \$1/MWh for microgrids [41]. The Monte Carlo simulation is applied to generate scenarios and simulate random outages of system components. Each possible system state is represented by a scenario. A uniformly distributed random number from 0 to 1 is sampled for representing the outages of generating units and transmission lines. If the random number is less than the associated forced outage rate, the corresponding generating unit or transmission line is on outage, otherwise it is in service [39], [40]. The scenario reduction is applied which reduces the number of scenarios from 1000 to 12 and the corresponding probabilities are demonstrated in Table III. The probability metrics based scenario reduction method [39] is applied in this paper. The proposed planning method is implemented on a 2.4-GHz personal computer using CPLEX 11.0 [42].

The following cases are studied:

Case 0: Base case planning of the main grid generating units

Case 1: Co-optimization planning of the main grid generating units and transmission lines

Case 2: Co-optimization planning of the main grid generating units with microgrids

Case 3: Co-optimization planning of the main grid generating units and transmission lines with microgrids

TABLE IV
CANDIDATE UNITS AND INSTALLATION YEARS

Candidate Unit	Bus	Capacity (MW)	Inv. Cost ($/kW)	Comm. (year)	Case 1	Case 2	Case 3
1	5	200	750	10	14	20	14
2	12	200	750	10	11	16	11
3	25	200	750	10	17	-	-
4	26	200	750	10	20	-	-
5	80	200	750	10	15	20	19
6	89	200	750	10	13	20	20
7	18	100	400	6	19	11	-
8	32	100	400	6	20	15	-
9	55	100	400	6	17	-	-
10	56	100	400	6	19	-	-
11	62	100	400	6	18	-	-
12	78	20	200	3	20	-	-
13	78	20	200	3	20	-	-
14	78	20	200	3	-	-	-
15	95	20	200	3	-	-	-
16	95	20	200	3	-	-	-

TABLE V
CANDIDATE LINES AND INSTALLATION YEARS

Candidate Line	From Bus	To Bus	Capacity (MW)	Inv. Cost ($/kW)	Comm. (year)	Case 1	Case 2	Case 3
1	8	5	200	267	5	5	-	5
2	11	12	100	196	4	-	-	-
3	26	30	200	860	5	-	-	-
4	38	37	200	375	5	15	-	-
5	77	78	100	124	4	-	-	-
6	94	100	100	580	4	20	-	-
7	99	100	100	813	4	-	-	-
8	17	113	100	301	4	-	-	-

Case 0: The existing system cannot satisfy the load growth in the planning horizon. The existing generation capacity is larger than the load in years 1–14; however, the system is unable to meet the load and satisfy the reliability requirements together in years 5–20. In years 5–20, the annual EENS limit is violated and additional load shedding is unavoidable. Accordingly, generating units 1–7 and 9–11 are installed by the proposed planning problem to meet the forecasted load. However, the expanded generation capacity does not satisfy system reliability requirements in the subproblems. Although, the original EENS is reduced once the new units are installed, the new EENS would violate the EENS limit in years 5–20. In this case, additional units would violate the EENS limit when the transmission network is congested.

Case 1: The 20-year co-optimization planning of the main grid generation and transmission expansion planning is applied without any microgrid installations. The candidate generating units and transmission lines installation years are shown in Tables IV and V, respectively. The installed generation capacity at the end of the planning horizon is 7 590 MW with a total planning cost of $4.496B. The total EENS is 862.47 MWh and the cost of unserved energy is $4M. Load shedding occurs partially at buses 1, 4, 35, 59, 60, 95, and 117. The load shedding in this case is an economic option that is offered by the planning solution. In this case, the proposed load shedding would replace the installation of candidate units 14–16.

Case 2: The co-optimization planning of microgrids and the main grid generation is considered. Table VI summarizes the total planning cost along with the expected cost of unserved energy. In Case 2, 42 microgrids are installed and a partial load shedding is applied to buses 4, 59, 60, and 82. Table IV shows that the microgrid installations would eliminate the requirement for the installation of generating units 3, 4 and 9–16. The total EENS is 1047.37 MWh which entails to a higher load shedding as compared to that in Case 1. In Case 1, we considered the installation of candidate transmission line 1 which would reduce the congestion on the existing line 4–5, and accordingly reduce the load shedding at bus 4. However in Case 2, a higher total EENS occurs when no microgrid is installed at bus 4. As will be discussed in Case 3, the system will consider the installation of a transmission line in order to reduce EENS.

TABLE VI
SUMMARY OF SYSTEM COSTS ($BILLION) (G: GENERATING UNIT, T: TRANSMISSION LINE, M: MICROGRID)

Costs ($Billion)	Case 1			Case 2			Case 3		
	G	T	M	G	T	M	G	T	M
Investment Cost	0.225	0.052	-	0.062	-	0.435	0.115	0.036	0.221
Operation Cost	4.215	-	-	3.916	-	0.017	4.045	-	0.009
Unserved Energy Cost	0.004			0.005			0.003		
Total Planning Cost	4.496			4.435			4.429		

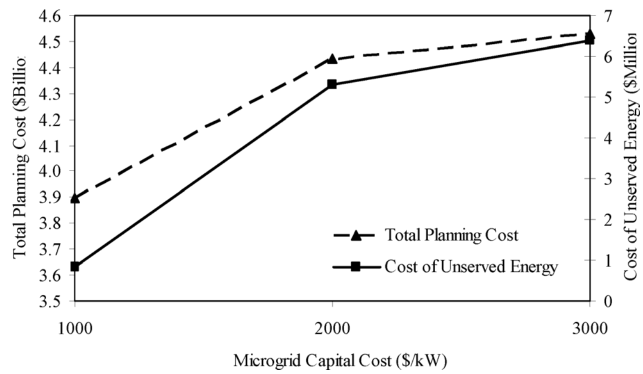

Fig. 3. Total planning cost and cost of unserved energy as a function of microgrid capital cost.

The total investment cost is increased and the total operation cost is decreased in Case 2 as compared to Case 1. The proposed microgrid installations will mitigate the congestion on transmission lines 2–12, 23–25 and 84–85. The generation supply by less expensive units will be increased in a less congested grid and the operation cost will be reduced. The installed microgrid capacity at the end of the planning horizon would supply 30% of the associated peak load, which shows that the majority of loads will be satisfied by the main grid generation. In this case, the total planning cost is lowered by 1.36% to $4.435B as compared to that in Case 1, which suggests that the Case 2 provides a more economical solution with a higher EENS.

Fig. 3 illustrates the total planning cost and the cost of unserved energy as a function of the microgrid capital cost. The microgrid capital cost depends on the type and the location of DER. A less expensive microgrid will result in a higher number of microgrid installations which will reduce the level of load shedding and the cost of unserved energy. In addition, fewer generating units will be installed at the main grid level. A microgrid with a capital cost of $1000/kW will result in the installation of 5 generating units and 52 microgrids, while a microgrid with a capital cost of $3000/kW will result in the installation of 9 generating units and 12 microgrids. Fig. 3 illustrates that the

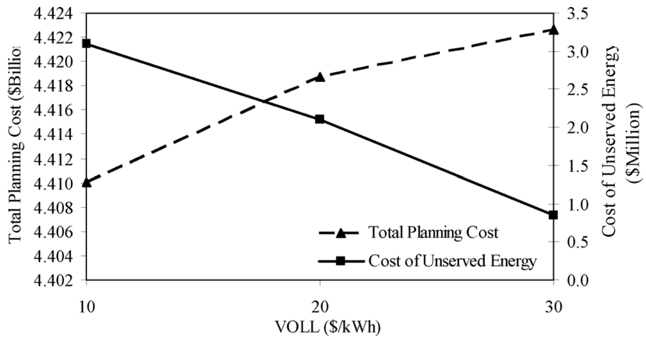

Fig. 4. Total planning cost and cost of unserved energy as a function of VOLL.

investment cost is a decisive factor in microgrid installations, though microgrids will offer low operation costs for supplying local loads. As microgrid investment costs increase, it will be more economical to build a candidate generating unit at the main grid level and/or consider additional load shedding as microgrid installations become inferior.

In this paper, VOLL is fixed at $10/kWh at all buses. However, VOLL depends on the types of customers, the amount and the duration of load interruptions, and the time in which the interruption occurs [43]. VOLL, which would impact the unserved energy, would accordingly influence microgrid investments. Fig. 4 illustrates the total planning cost and the cost of unserved energy as a function of VOLL. Fig. 4 shows that smaller VOLL will result in higher unserved energy. On the other hand, higher VOLL will reduce the system EENS and the cost of unserved energy which corresponds to a higher investment in system planning. Therefore, VOLL will control the expected level of load shedding at each load bus. When VOLL is $10/kWh, load will be partially curtailed at buses 4, 36, 59, 60, 82, 93, and 94. As VOLL increases to $20/kWh, more microgrids are installed and the load shedding is dropped at buses 36, 93, 94. When VOLL is $30/kWh, an additional microgrid is installed at bus 62. So, higher VOLL will results in additional microgrid investments.

Case 3: A co-optimization expansion planning is considered for the microgrids and the main grid generating units and transmission lines. Table IV shows that only 4 units are installed. Transmission line 1 is installed at year 5 to reduce the congestion on existing line 4–5, enhance generation of unit 1 (at bus 5) and reduce load shedding in bus 4. The low capital cost of this candidate transmission line makes it a more viable investment option as compared to a microgrid installation at bus 4. It is presumed that the microgrids will be installed in a year. As the commissioning time of generating units and transmission lines are large, several microgrids are installed in years 1–4 to reduce the system EENS and meet the system reliability requirements. In this case, a total of 31 microgrids are installed in the planning horizon and transmission line flows are altered as compared to previous cases.

The transmission congestion on lines 4–5, 15–17, 23–25, 84–85, and 17–113 is mitigated. The total planning cost is less by 1.49% as compared to that in Case 1 and 0.13% as compared to that in Case 2. The presented result indicates that higher reliability and economic milestones are attainable in a co-optimization planning of the main grid and microgrids.

The microgrids represent the aggregation of several buses and, as such, can be installed at any main grid regions. In the given system, bus 117 represents a remote bus which is interconnected with the rest of the system through a single transmission line. The annual peak load at this bus in year 1 is 4 MW which increases to 6.88 MW in year 20. The lack of enough generation at this bus, following the line outage, will result in the curtailment of the entire load. The outage of this single line may result in an expected unserved energy of 643.48 MWh (when peak load with probability of 0.042 occurs in a scenario). The load shedding at this bus may be reduced by the installation of either a second transmission line to connect this bus to the rest of the system or a microgrid at this remote bus location. The first option may feature high installation costs and large commissioning time of the transmission line. Therefore, a microgrid is considered as a quick and efficient solution to this curtailment problem.

Next, we would limit the number of microgrid installations to NQ, where $\sum_m u_{qmt} \leq NQ, \forall t$ in order to provide an insight on a reasonable number of microgrid installations, how microgrid installations would affect operation and reliability results, and the most suitable buses for microgrid installations in the expansion planning problem. Table VII summarizes the results. The necessary investments on generating units and transmission lines will drop when a higher number of microgrids are installed at proper locations. The locations and the number of microgrids will depend on the maximum number of microgrids that can potentially be installed. The microgrid installations could reduce the annual EENS. However, the total EENS will not change monotonically with the number of installed microgrids. Comparing the load shedding level in Cases 1 and 2 with the number of installed microgrids in Table VII, it is clear that the majority of microgrids are installed at buses where load shedding occurs (i.e., buses 1, 35, 60, 95). There are a few other buses with load shedding (i.e., buses 4, 59, 82) where microgrids are not ultimately installed. The additional dispatch of generating unit at the main grid level would mitigate the load shedding at these buses. Therefore, microgrids are primarily installed at buses where the load shedding is eminent and local generating units are insufficient to supply the designated load.

VI. Discussions

Microgrids increase the system reliability (by reducing load shedding and enhancing the local controls) and improve the system economics (by reducing system congestion, enhancing the operation of less expensive units, and reducing the need for additional generation and transmission investments). Specific features of the proposed microgrid-based co-optimization planning of generation and transmission are listed as follows:

— Co-optimization expansion planning: The microgrid-based planning incorporates a co-optimization planning of generation and transmission. The microgrid investment decisions are made as planning alternatives to those of generation and transmission.

— Stochastic planning approach: A stochastic approach is applied to the proposed co-optimization planning approach

TABLE VII
SUMMARY OF MICROGRID INSTALLATIONS

Max. No. of Microgrids	Microgrid Installations	Unit Installations	Line Installations	Total EENS (MWh)
1	60	1-11	1, 4, 6	958
2	35, 95	1-13	1, 4, 6	1209
3	1, 35, 60	1-11	1, 4	862
4	35, 39, 41, 60	1-3, 5-11	1, 4	968
5	35, 39, 41, 45, 60	1-3, 5-11	1, 4	1055
6	1, 35, 39, 41, 60, 83	1-3, 5-7, 9-11	1, 4	526
7	1, 11, 35, 39, 41, 45, 60	1-3, 5-7, 9-11	1, 4	380
8	1, 11, 35, 39, 41, 45, 60, 95	1-3, 5-7, 9-10	1, 4	707
9	1, 11, 35, 39, 41, 45, 60, 88, 95	1, 2, 4-7, 10, 11	1, 4	1208
10	1, 13, 33, 35, 39, 41, 45, 60, 83, 95	1-3, 4-9	1	822

to calculate the system reliability criterion. The stochastic planning employs the Monte Carlo simulation for the modeling of random outages of system components. The stochastic planning approach considers the microgrid as an alternative for enhancing the system reliability when considering the main grid contingencies.

— Enhancements in system operation: The generation and transmission upgrades are subject to large commissioning time and depend on the availability of geographical locations in the main grid; however, microgrids could be installed quickly in any selected system buses, providing a quick and efficient solution to the system reliability requirements.

— Optimal location of microgrids: All system buses are considered as potential options for microgrid installations. Most suitable buses for the installation of microgrids are located at constrained geographical locations which are often subject to hourly load curtailments.

— Economics of microgrids: Despite higher capital investment requirements, microgrids offer economic benefits to power systems. Microgrids could lower the cost of supplying the local loads by reducing the network congestion and enhancing the utilization of less expensive units in power systems.

— Economics of load shedding: A high VOLL in the proposed planning approach would justify the microgrid installation, while for lower VOLLs the economics of load shedding could be comparable with those of a microgrid installation.

— Computational efficiency: Microgrid-based co-optimization planning would include additional binary and continuous variables associated with microgrid investments and operations. In order to reduce the computational burdens, the reliability requirements are examined in annual reliability subproblems as post-processor, which would reduce the size of the microgrid-based planning problem and makes it possible to apply the approach to large-scale planning problems.

VII. CONCLUSION

A microgrid-based co-optimization planning model considering the power system reliability and economic criteria was proposed. An efficient formulation of the microgrid installation was proposed, incorporating investment and operation costs of microgrids. The proposed problem considered the annual reliability as a planning criterion. The solution of the planning problem was obtained by minimizing the investment and operation costs of generating units, transmission lines and microgrids, as well as the cost of unserved energy. The problem utilized the proposed plan to calculate the system annual reliability index and compare it with the targeted EENS value. In the case of violations, reliability constraints were formed and added to the next iteration of the planning problem. The proposed model was analyzed further through numerical simulations, where it was shown that microgrid investments in the power system can provide significant reliability and economic benefits and are viable options for system upgrades when large investments on new generation and transmission facilities are not forthcoming.

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Amin Khodaei (M'11) received the B.S. degree from the University of Tehran, Tehran, Iran, in 2005, the M.S. degree from the Sharif University of Technology, Tehran, Iran, in 2007, and the Ph.D. degree from the Illinois Institute of Technology (IIT), Chicago, in 2010, all in electrical engineering.

He was a visiting faculty (2010–2012) in the Robert W. Galvin Center for Electricity Innovation at IIT. He joined the University of Houston, Houston, TX, in 2012 as an Assistant Professor. His research interests include operation planning and economics of electric power systems.

Mohammad Shahidehpour (F'01) is the Bodine Chair Professor and Director of the Robert W. Galvin Center for Electricity Innovation at Illinois Institute of Technology, Chicago.

He is the recipient of the Honorary Doctorate from the Polytechnic University of Bucharest in Romania. He is a Research Professor at King Abdulaziz University in Jeddah, Saudi Arabia, North China Electric Power University in Beijing, China, and Sharif University in Tehran, Iran.

Dr. Shahidehpour is an IEEE Distinguished Lecturer, Chair of the 2012 IEEE Innovative Smart Grid Technologies Conference, Chair of the 2012 Great Lakes Symposium on Smart Grid and the New Energy Economy, and the Editor-in-Chief of the IEEE TRANSACTIONS ON SMART GRID. He is the recipient of the 2012 IEEE PES Outstanding Power Engineering Educator Award.