AC vs. DC Microgrid Planning

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Abstract**—This paper presents a microgrid planning model for determining the optimal size and the generation mix of distributed energy resources (DERs) as well as the microgrid type, i.e., AC or DC. Considering the growing ratio of DC loads and DERs, DC microgrids could be potentially more beneficial than AC microgrids by avoiding the need to synchronize generators, reducing the use of converters, facilitating the connection of various types of DERs and loads to the microgrid common bus with simplified interfaces, and reducing losses associated with the AC-DC energy conversion. The microgrid type is selected based on economic considerations, where the planning objective includes the investment and operation costs of DERs, cost of energy purchase from the main grid, and the reliability cost. Numerical simulations exhibit the effectiveness of the proposed model and investigate in detail the impact of variety of factors on planning results, including the ratio of critical loads, the ratio of DC loads, and the efficiency of inverters and converters.**

Index Terms**—Microgrid planning, AC microgrid, DC microgrid, distributed energy resource.**

NOMENCLATURE

Indices

b	Index for hour
ch	Superscript for energy storage charging mode
dch	Superscript for energy storage discharging mode
h	Index for day
i	Index for DERs
inv	Subscript for DC-to-AC inverters
rec	Subscript for AC-to-DC rectifiers
t	Index for year

Sets

G	Set of all dispatchable units
G_{ac}	Set of AC dispatchable units
G_{dc}	Set of DC dispatchable units
I	Set of DC-to-AC inverters
R	Set of AC-to-DC rectifiers
S	Set of energy storage systems
W	Set of all nondispatchable units
W_{ac}	Set of AC nondispatchable units
W_{dc}	Set of DC nondispatchable units

Parameters

c	Generation price for dispatchable units
CC	Annualized investment cost of generating units
CE	Annualized investment cost of storage – energy
CI	Annualized investment cost of DC-to-AC inverters
CP	Annualized investment cost of storage – power
CR	Annualized investment cost of AC-to-DC rectifiers
C^{cap}	Allowable energy storage installation capacity
d	Discount rate
D	Local demand
M	Large positive constant
P^{cap}	Allowable DER installation capacity
$P_M^{\max}$	Flow limit between the microgrid and the main grid
pp	Normalized forecast of nondispatchable generation
u	Binary islanding parameter
α	Ratio of DC loads to total loads
β	Ratio of critical loads to total loads
κ	Coefficient of present-worth value
ρ	Market price
v	Value of lost load (VOLL)
η	Efficiency (energy storage, inverters, and rectifiers)

Variables

$C^{\max}$	Installed energy storage capacity
IC	Total investment cost
LS	Load curtailment
OC	Total operation cost
P	DER output power
$P^{\max}$	Installed DER capacity
P_M	Main grid power
RC	Total reliability cost
z	Microgrid investment state (0 if AC, 1 if DC)

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I. INTRODUCTION

MICROGRIDS have attracted significant attention in recent years due to providing significant advantages for electricity consumers and power grid operators. Microgrid deployments are trusted to improve power quality, reduce emissions, reduce network congestion and power losses, increase energy efficiency, and potentially improve system economics. Microgrids could also eliminate investments on additional generation and transmission facilities to supply remote loads. Moreover, microgrids islanding capability in the event of faults or disturbances in upstream networks would enhance grid and customers' reliability and resilience [1]-[12].

Microgrids can be categorized into different groups based on the type (such as campus, military, residential, commercial, and industrial), the size (such as small, medium, and large scales), the application (such as premium power, resilience-oriented, loss reduction, etc.), and the connectivity (remote and grid-connected). Based on the voltages and currents adopted in a microgrid, however, three microgrid types can be identified: AC, DC, and hybrid. In AC microgrids, all DERs and loads are connected to a common AC bus. DC generating units as well as energy storage will be connected to the AC bus via DC-to-AC inverters, and further, AC-to-DC rectifiers are used for supplying DC loads. In DC microgrids, however, the common bus is DC, where AC-to-DC rectifiers are used for connecting AC generating units, and DC-to-AC inverters are used for supplying AC loads. In hybrid microgrids, which could be considered as a combination of AC and DC microgrids, both types of buses exist, where the type of connection to each bus depends on the proximity of the DER/load to the bus. Extensive studies can be found on different aspects of microgrids operation and control, where the majority of these studies focus on AC microgrids, perceivably due to the connection to the AC utility grid and the utilization of AC DERs. DC microgrids could however offer several advantages when studied in detail and compared with AC microgrids: 1) higher efficiency and reduced losses due to the reduction of multiple converters used for DC loads, 2) easier integration of various DC DERs, such as energy storage, solar PV, and fuel cells, to the common bus with simplified interfaces, 3) more efficient supply of DC loads, like electric vehicles and LED lights, 4) eliminating the need for synchronizing generators, which enables rotary generating units to operate at their own optimum speed, and 5) enabling bus ties to be operated without the need for synchronizing the buses [13]. These benefits, combined with the significant increase in DC loads such as personal computers, laptop computers, LED lights, data and telecommunication centers, and other applications where the typical 50-Hz and 60-Hz AC systems are not available, could potentially introduce DC microgrids as viable and economic solutions in addressing future energy needs.

The prior research on DC microgrid planning is rather limited and available studies on microgrid planning mostly focus on AC microgrids. The study in [14] proposes a planning model for AC microgrid considering uncertain physical and financial information. In this study, the microgrid planning problem is broken down into an investment problem and an operation subproblem. The optimality of the solution is examined by employing the optimal planning decisions obtained from the master problem in the subproblem under uncertain conditions. The study in [15] suggests an operation modeling of hybrid AC-DC microgrids. It explains that the operation model of such hybrid microgrid consists of system and device levels. This model includes advantages of both AC and DC microgrids, and performs both optimal scheduling and voltage control. The study in [16] proposes an operation planning model considering load/generation changes for a low voltage DC microgrid including DC sources like battery, fuel cell, and PVs. The objective of the study is to minimize daily operation costs. The model utilizes a multi-path dynamic programming approach to solve the problem. The study in [17] presents a multi-objective optimal scheduling of a DC microgrid consisting of a PV system and an electric vehicle charging station. In this study, the cost of electricity and energy circulation of storage are taken as objective functions, and the mathematical model is built and solved to obtain the Pareto optimal solution. The study in [18] investigates a control system for hybrid AC-DC microgrids connected by multi-level inverters. The droop control technique is offered to manage power flows between AC microgrid, DC microgrid, and the main grid. The study in [19] discusses the power management in a hybrid AC-DC microgrid and proposes an interlinking AC-DC converter accompanied by a suitable control system. The power flow between different sources throughout both microgrids is controlled. The hybrid AC-DC microgrid allows different loads and DERs to connect with the minimum need for electrical conversion, which decreases the cost and energy losses. The study in [20] states that the efficiency of distributed generations and energy storage systems in a microgrid might reduce because of microgrid operation, hence running some consumers into problem. This study proposes an optimized operation planning for distributed generations and energy storage systems in microgrids to solve this issue.

It is assumed in this paper that the microgrid developer is planning to deploy a microgrid, however, the challenge is to determine the type of the microgrid, i.e., either AC or DC, based on the system characteristics and accordingly determine the optimal DER generation mix. This paper aims at proposing a microgrid planning model with the overarching goals of 1) Determining the optimal DER generation mix; 2) Determining the optimal type of the microgrid, i.e., either AC or DC, from an economic perspective; and 3) Identifying threshold ratios of DC loads which make the DC microgrid a more economically viable alternative than the AC microgrid.

Although the proposed planning model can be extended to include hybrid microgrids, it is limited in this paper to the modeling of individual AC and DC microgrids. The proposed microgrid planning model minimizes the total planning cost associated with the investment costs of DERs, AC-to-DC rectifiers, and DC-to-AC inverters, as well as the microgrid operation and reliability costs.

The rest of the paper is organized as follows. Sections II and III present the model outline and the formulation of the proposed microgrid planning problem, respectively. The numerical simulations for a test microgrid are performed in Section IV. Section V provides a discussion on the proposed model, and Section VI concludes the paper.

II. Microgrid Planning Problem Model Outline

The investment cost is typically higher for DERs compared to conventional energy resources within large-scale power plants due to economies-of-scale of the latter. Nevertheless, DERs could provide less expensive energy in comparison with the energy purchased from the main grid specifically during peak hours when the market price is high. The energy storage could be further employed to be charged by the power from the main grid during low-price hours and discharged during high-price hours. One important and salient feature of microgrids that increases the reliability is their islanding capability which allows microgrids to be disconnected from the main grid in the presence of faults, disturbances, or voltage fluctuations in the upstream network. However, if after disconnecting from the main grid, the microgrid could not supply all the loads, some loads should be curtailed, but critical loads will still be supplied. Another economic benefit of the microgrid is selling back the excess power to the main grid. The microgrid economic viability is ensured when the total microgrid revenue from all available value streams in a specified time horizon exceeds the microgrid total investment cost. The total planning cost is comprised of three parts: the investment cost, the operation cost, and the reliability cost. The investment cost is long-term, and is calculated annually while the operation and reliability costs are short-term, and should be calculated hourly for each day of the planning horizon.

In reality, several components should be considered to install the microgrid, but only the investment cost of DERs, rectifiers and inverters are included in this paper. Other costs associated with distribution network upgrade and installation of additional transformers, switches, measurement devices, and controllers are ignored in this study since these costs will be similar in both types of the microgrid. A general structure of DC microgrids is shown in Fig. 1. In DC microgrids, three-phase AC-to-DC rectifiers and transformers are required to connect AC DERs to the common bus, single- and three-phase DC-to-AC inverters are needed for supplying AC loads, and a three-phase DC-to-AC/AC-to-DC converter, a transformer, and a point of common coupling switch are required for connecting the microgrid to the utility grid.

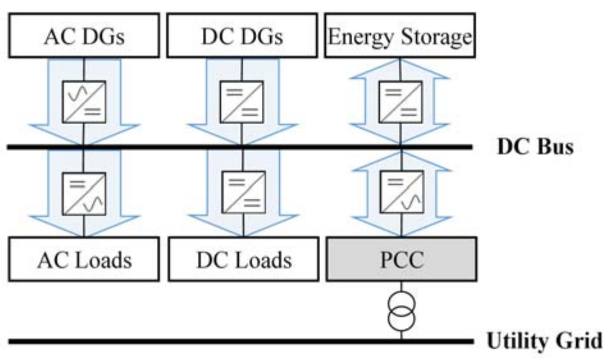

Fig. 1. General structure of DC microgrids

A general structure of AC microgrids is shown in Fig. 2. In AC microgrids, three-phase DC-to-AC inverters are required to connect DC DERs to the common bus, three-phase AC-to-DC rectifiers are needed for supplying DC loads, and similar to DC microgrids, a transformer and a point of common coupling switch are required to connect the microgrid to the utility grid. The direction of arrows in Figs. 1 and 2 shows the direction of power flow. It should be noted that different DC loads require different DC voltage levels, so some DC-to-DC converters have to be considered as well in order to change the voltage level of the DC sources to desired levels. In both microgrids, a common bus is considered to show all the connections of loads and DERs. In reality, however, the common bus could represent one or more loop/radial distribution networks that connect loads and DERs within the microgrid. In DC microgrids, the common bus would handle DC voltages and currents, while in AC microgrids the common bus would be used for AC voltages and currents.

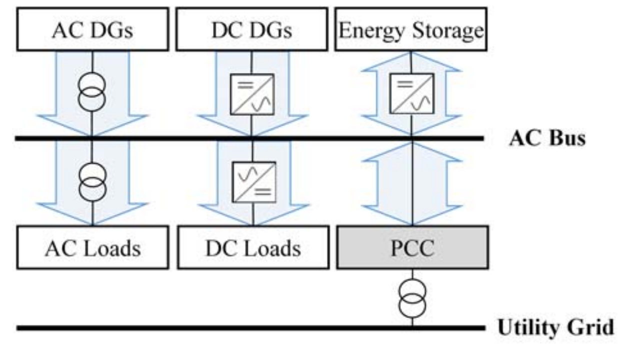

Fig. 2. General structure of AC microgrids

The capacity of lines in a microgrid distribution network is typically much higher than the power transferred through the lines, therefore, the power flow is not considered in the proposed planning problem as the congestion is less likely and would not impact the planning results. Moreover, although the proposed planning model can be extended to include hybrid microgrids, it is limited in this paper to the modeling of AC and DC microgrids. The hybrid microgrid planning problem will be investigated as a follow-on work.

III. Microgrid Planning Problem Formulation

The objective of the microgrid planning problem is to minimize the microgrid total planning cost (1), which comprises the investment cost of DERs, rectifiers, and inverters (*IC*), the microgrid operation cost (*OC*), and the reliability cost (*RC*). The investment, operation, and reliability costs are determined in (2)-(5). Associated constraints are defined in (6)-(17). The type of the microgrid, i.e., either AC or DC, would impact the components to be installed in the microgrid, and accordingly, alter the investment cost. Constraints (2) and (3) respectively define the DC investment cost and the AC investment cost, based on a binary decision variable z. If the microgrid is DC, the binary decision variable is set to one, relaxing (3), and the investment cost would be determined by (2). Similarly, if the microgrid is AC, the binary decision variable is set to zero, relaxing (2), and the investment cost would be determined by (3).

$$\min IC + OC + RC \tag{1}$$

$$-M(1-z) \le IC - \left(\begin{array}{l} \sum_t \sum_{i\in\{G,W\}} \kappa_t CC_{it} P_i^{\max} + \\ \sum_t \sum_{i\in S} \kappa_t (CP_{it} P_i^{\max} + CE_{it} C_i^{\max}) + \\ \sum_t \sum_{i\in\{G_{ac},W_{ac}\}} \kappa_t CR_{it} P_i^{\max} + \\ \sum_t \sum_{i\in I} \kappa_t CI_{it} (1-\alpha).\max(D_{bht}) + \\ \sum_t \sum_{i\in I} \kappa_t CI_{it} P_M^{\max} \end{array} \right) \le M(1-z) \tag{2}$$

$$-Mz \le IC - \begin{pmatrix} \sum_t \sum_{i\in\{G,W\}} \kappa_t CC_{it} P_i^{\max} + \\ \sum_t \sum_{i\in S} \kappa_t (CP_{it} P_i^{\max} + CE_{it} C_i^{\max}) + \\ \sum_t \sum_{i\in\{G_{dc},W_{dc},S\}} \kappa_t CI_{it} P_i^{\max} + \\ \sum_t \sum_{i\in R} \kappa_t CR_{it} \alpha . \max(D_{bht}) \end{pmatrix} \le Mz \quad (3)$$

$$OC = \sum_t \sum_h \sum_b \sum_{i\in G} \kappa_t c_i P_{ibht} + \sum_t \sum_h \sum_b \kappa_t \rho_{bht} P_{M,bht} \quad (4)$$

$$RC = \sum_t \sum_h \sum_b \kappa_t v_{bht} LS_{bht} \quad (5)$$

AC and DC microgrids have some similar components in the investment cost. The first two terms within the investment cost in (2) and (3) indicate the investment cost of DERs and energy storage, respectively. The investment cost of DERs depends on their installed power capacity which will be determined by the optimization problem. The investment cost of energy storage further depends on its installed energy capacity. A single-step price curve is considered for DERs, which could be simply extended to a multi-step price curve. If the microgrid is DC, the output voltage of AC generating units should be converted to DC using rectifiers. Therefore, another term that should be considered is related to the investment cost of AC-to-DC rectifiers. Additionally, there are AC loads in the microgrids requiring the use of DC-to-AC inverters. As a result, the investment cost of these inverters is included in the investment cost. The last term of the investment cost considers the DC-to-AC inverter which is used for connecting the DC microgrid to the utility grid. For AC microgrids, as proposed in (3), DC-to-AC inverters have to be used for connecting DC units to the microgrid, and AC-to-DC rectifiers are needed for supplying DC loads. These costs are included in the investment cost as well.

The operation cost (4) includes the generation cost of dispatchable generating units and the cost of energy purchase from the main grid, which is defined as the amount of purchased energy times the market price at the point of common coupling. If the microgrid is exporting its excess power to the main grid, the main grid power P_M would be negative (assumed to be paid at the market price under net metering); hence, there would be a benefit from selling the excess power. On the other hand, if there is a need for importing power from the main grid, P_M would be positive, increasing the operation costs. The reliability cost (5), which is the cost of unserved energy, is defined as the load curtailment quantity multiplied by the value of lost load (VOLL). VOLL represents customers' willingness to pay for reliable electricity service in order to avoid outage. VOLL highly depends on sector or customer type, timing of outage, duration of outage, and time of advanced notification of outage and preparation. Generally, VOLL for residential customers ranges from approximately \$0/MWh to \$17,976/MWh, while for commercial and industrial customers ranges from \$3,000/MWh to \$53,907/MWh [21]. Higher VOLLs represent more critical loads [22]-[23]. A discount rate d is considered in order to evaluate the objective in terms of discounted costs. The present-worth cost component κ_t is present in all parts of the cost function, and is calculated as $\kappa_t = 1/(1+d)^{t-1}$. In (1)-(5), investment costs are calculated annually while operation and reliability costs are calculated hourly and summed over all the years in the planning horizon.

Islanding is the most salient feature of microgrids, which enables the microgrid to be disconnected from the main grid in case of upstream network disturbances. In order to include the islanding ability of the microgrid, it is required to consider a condition to make sure that dispatchable generation capacity installed in the microgrid is adequate to seamlessly supply critical loads (6). The parameter β defines the peak ratio of critical loads to total loads.

$$\beta \max(D_t) \le \sum_{i\in G} P_i^{\max} \quad (6)$$

Sum of the power from the main grid and from all DERs, including dispatchable and nondispatchable units as well as energy storage, should be equal to the total load in each scheduling hour. Equations (7) and (8) consider the power balance equation in DC and AC microgrids, respectively. If the microgrid is DC, the binary decision variable is set to one, thus (8) would be relaxed, and (7) would be applied. Similarly, if the microgrid is AC, (7) would be relaxed and (8) would be applied.

$$-M(1-z) \le \begin{pmatrix} \sum_{i\in\{G_{dc},W_{dc}\}} P_{ibht} + \sum_{i\in S} (P_{ibht}^{dch} - P_{ibht}^{ch}) + \\ \left(\sum_{i\in\{G_{ac},W_{ac}\}} P_{ibht} + P_{M,bht} \right) . \eta_{rec} \\ + LS_{bht} - \alpha . D_{bht} - \dfrac{(1-\alpha) . D_{bht}}{\eta_{inv}} \end{pmatrix} \le M(1-z) \quad (7)$$

$\forall b, \forall h$

$$-Mz \le \begin{pmatrix} \sum_{i\in\{G_{ac},W_{ac}\}} P_{ibht} + \\ \left(\sum_{i\in\{G_{dc},W_{dc}\}} P_{ibht} + \sum_{i\in S} (P_{ibht}^{dch} - P_{ibht}^{ch}) \right) . \eta_{inv} + \\ P_{M,bht} + LS_{bht} - (1-\alpha) . D_{bht} - \dfrac{\alpha . D_{bht}}{\eta_{rec}} \end{pmatrix} \le Mz \quad (8)$$

$\forall b, \forall h$

In DC microgrids, since power conversion causes power loss, an efficiency coefficient is defined in (7) for AC-to-DC rectifiers, used for converting the output of AC generating units and the power from the main grid, and for DC-to-AC inverters, used for supplying AC loads. Similar efficiency coefficients are considered for the AC microgrid (8).

The planning problem is further subject to constraints associated with the main grid power limits (9), dispatchable and nondispatchable unit operation and planning (10)-(12), energy storage (12)-(16), and load curtailment (17).

$$-P_M^{\max} u_{bht} \le P_{M,bht} \le P_M^{\max} u_{bht} \qquad \forall b, \forall h \quad (9)$$

$$0 \le P_{ibht} \le P_i^{\max} \qquad \forall i \in \mathrm{G}, \forall b, \forall h \quad (10)$$

$$P_{ibht} = P_i^{\max} . pp_{ibht} \qquad \forall i \in \mathrm{W}, \forall b, \forall h \quad (11)$$

$$P_i^{\max} \le P_i^{cap} \qquad \forall i \in \{\mathrm{G,W,S}\} \quad (12)$$

$$0 \le P_{ibht}^{dch} \le P_i^{\max} \qquad \forall i \in \mathrm{S}, \forall b, \forall h \quad (13)$$

$$0 \le P_{ibht}^{ch} \le P_i^{\max} \qquad \forall i \in S, \forall b, \forall h \qquad (14)$$

$$C_i^{\max} \le C_i^{cap} \qquad \forall i \in S \qquad (15)$$

$$0 \le \sum_{k \le b} (P_{ikht}^{ch} - P_{ikht}^{dch} / \eta_i) \le C_i^{\max} \qquad \forall i \in S, \forall b, \forall h \qquad (16)$$

$$0 \le LS_{bht} \le D_{bht} \qquad \forall b, \forall h \qquad (17)$$

The amount of exchanged power with the main grid is limited by the capacity of the line connecting the main grid to the microgrid (9). In (9), the islanding capability of the microgrid is considered by defining a binary parameter which controls microgrid islanding. The power generated by dispatchable units is limited by their installed capacity (10). For nondispatchable units, a variable and a parameter are used to consider their generation. Similar to dispatchable units, the variable $P_i^{\max}$ represents their installed capacity, which will be determined via the optimization problem. The parameter pp_{ibht} represents the normalized generation forecast of nondispatchable units, and has a value between 0 and 1 (11). Once a forecast is obtained, it is divided by the rated power of the candidate DER, hence, the normalized generation forecast is obtained. In this case, the selected size of the nondispatchable unit will be considered as a scaling factor to scale up/down the normalized generation forecast and further obtain the actual generation. All DERs have an allowable installation capacity, and their installed capacity cannot exceed this limit (12). The allowable installation capacity may be obtained from budget limitations, choice of technology, or space limitations. The energy storage charging and discharging power in all hours is limited by its installed capacity (13)-(14). The installed energy capacity of the energy storage is limited by its allowable installation energy capacity (15). Additionally, its stored energy is determined based on the net charged power, efficiency, and the stored energy in previous hours (16). It is further ensured that in case of local curtailments, the hourly curtailed load does not exceed the hourly total load (17).

IV. Numerical Simulations

A microgrid is to be installed for a group of electricity customers with a peak annual load demand of 8.5 MW. The set of DERs used in this study includes four AC dispatchable units, one AC nondispatchable unit (wind generator), one DC dispatchable unit (fuel cell), one DC nondispatchable unit (solar PV), and one energy storage, as represented in Tables I-III. The cost of converters is provided in Table IV. The load, renewable energy, and market price are forecasted based on historical data obtained from the Illinois Institute of Technology Campus Microgrid [24]. Data of wind, solar, fuel cell, and converters are gathered from [25]-[28]. The efficiency of energy storage and VOLL are considered to be 90% and $10,000/MWh, respectively. The planning horizon is 20 years. The lifetime of candidate DERs is considered to be equal to the planning horizon, i.e., 20 years. Twelve hours of islanding is considered in each planning year. The microgrid planning problem was implemented on a high performance computing server consisting of four 10-core Intel Xeon E7-4870 2.4 GHz processors. The problem was formulated by mixed-integer programming (MIP) and solved by CPLEX 12.6 [29]. Following cases are studied. The approximate running time for each simulation is 118-155 minutes.

Case 0: Base case microgrid planning
Case 1: Sensitivity analysis on the ratio of DC loads
Case 2: Sensitivity analysis on the ratio of critical loads
Case 3: Sensitivity analysis on the efficiency of AC-to-DC rectifiers and DC-to-AC inverters
Case 4: Sensitivity analysis on the market price

TABLE I
DISPATCHABLE UNITS CHARACTERISTICS

Unit No.	Type	Allowable installation capacity (MW)	Cost Coefficient ($/MWh)	Annualized Investment Cost ($/MW)
1	Gas	5	90	50,000
2	Gas	5	90	50,000
3	Gas	3	70	70,000
4	Gas	3	70	70,000
5	Fuel Cell	1.5	175	360,000

TABLE II
NONDISPATCHABLE UNITS CHARACTERISTICS

Unit No.	Type	Allowable Installation Capacity (MW)	Cost Coefficient ($/MWh)	Annualized Investment Cost ($/MW)
6	Wind	2	0	132,000
7	Solar	2	0	133,000

TABLE III
ENERGY STORAGE CHARACTERISTICS

Storage No.	Allowable Installation Capacity (MW)	Allowable Installation Energy (MWh)	Annualized Investment Cost – Power ($/MW)	Annualized Investment Cost – Energy ($/MWh)
1	1	6	60,000	30,000

TABLE IV
ANNUALIZED INVESTMENT COST OF CONVERTERS

Three-Phase AC-to-DC Rectifier ($/MW)	Single-Phase DC-to-AC Inverter ($/MW)	Three-Phase DC-to-AC Inverter ($/MW)
4,200	6,000	6,500

Case 0: Initial values for the ratio of DC loads α, the ratio of critical loads β, and the efficiency of inverters and rectifiers η, are chosen to be 0.40, 0.50, and 0.70, respectively. The microgrid planning solution would install dispatchable units 3 and 4 and the solar unit all with the maximum allowable capacity. The planning solution would be the AC microgrid. The total planning cost in the base case is $25,608,640 with a cost breakdown of $6,679,653, $18,614,730, and $314,251 for the investment, operation, and reliability costs, respectively.

Case 1: In this case, the effect of changing the ratio of DC loads α on the type of the microgrid and installation of DERs is studied. The ratio of DC loads is changed by a step of 0.1 while all other parameters are kept unchanged. Results are represented in Tables V and VI. For values of α between 0 and 0.4, the microgrid planning solution would install dispatchable units 3-4 and the solar unit, while by changing α between 0.5-0.8, dispatchable units 1 and 2 are also installed. However, for α=0.9 and 1, units 1 and 2 are not installed anymore, and the microgrid planning solution would install the energy storage since the type of the microgrid is DC. The obtained results advocate that the installation of dispatchable units 3 and 4 with a higher investment cost is more economical than that of units 1 and 2. The reason is that units 3 and 4 offer a less expensive power compared to units 1 and 2. Additionally, between the two available nondispatchable units, the solar unit is installed for all values of α although it has a higher investment cost than the wind unit since the generation pattern of the solar unit partially coincides with market price and load variations. The daily values of load, solar generation, and market price, averaged over one year, are shown in Fig. 3 to demonstrate the partial correlation of the solar generation with the market price and the load. According to Fig. 3, during the day, especially at peak hours, the market price is higher, and the solar unit generates power. Therefore, part of loads could be supplied by solar generation. On the other hand, the wind energy is available mostly at early morning hours, when the market price is relatively low. As expected, according to results and based on the values of β and η, increasing the ratio of DC loads causes the microgrid to shift from AC (associated with z=0) to DC (associated with z=1). According to Table VI, by increasing α from 0.4 to 0.8, the microgrid investment cost increases because of increasing the installed capacity of units 1 and 2 and also increasing the investment cost of rectifiers for supplying DC loads. For values of α between 0.4 and 0.8, the operation cost would increase as well since the amount of hourly power generated by dispatchable units 1 and 2 increases. By increasing α from 0.8 to 0.9, again the investment cost rises due to the installation of the energy storage, but the operation cost would decrease. The investment and operation costs would decrease by increasing α from 0.9 to 1. The investment cost drops as there are not any AC loads in the microgrid when α=1, thus the investment cost of inverters is eliminated. The operation cost drops as the overall exchanged power with the main grid decreases by changing all loads to DC. Accordingly, the microgrid total planning cost would decrease by increasing α from 0.9 to 1. An interesting point is the change in the total planning cost by changing the load mixture. According to Table VI, increasing the ratio of DC loads would cause an increase followed by a decrease in the total planning cost. Therefore, it would identify threshold ratios of DC loads which make the DC microgrid a more economically viable solution than the AC microgrid. In other words, for ratios smaller than the threshold ratio, AC microgrid would be more economical and for ratios larger than that, DC microgrid would be more economical.

TABLE V
INSTALLED DER CAPACITY (MW) ($\beta = 0.50, \eta = 0.70$)

α	z	DER								
		1	2	3	4	5	6	7	Storage	
									P	E
0.00-0.40	0	0	0	3.0	3.0	0	0	2.0	0	0
0.50	0	0.03	0.03	3.0	3.0	0	0	2.0	0	0
0.60	0	0.15	0.15	3.0	3.0	0	0	2.0	0	0
0.70	0	0.27	0.27	3.0	3.0	0	0	2.0	0	0
0.80	0	0.40	0.40	3.0	3.0	0	0	2.0	0	0
0.90, 1.00	1	0	0	3.0	3.0	0	0	2.0	1.0	4.44

TABLE VI
MICROGRID COSTS ($\beta = 0.50, \eta = 0.70$)

α	Investment Cost	Operation Cost	Reliability Cost	Total Cost
0.40	6,679,653	18,614,730	314,251	25,608,640
0.50	6,740,727	19,514,640	359,810	26,615,180
0.60	6,888,104	20,372,440	370,847	27,631,390
0.70	7,035,482	21,230,250	381,884	28,647,620
0.80	7,182,860	22,088,070	392,922	29,663,850
0.90	9,736,027	20,640,090	247,109	30,623,220
1.00	9,688,322	19,335,080	190,476	29,213,880

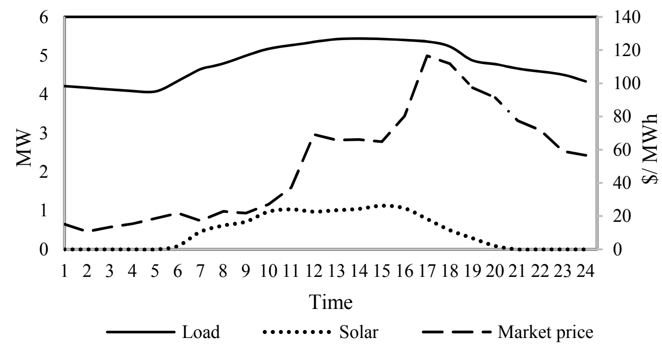

Fig. 3. Annual average value of load and solar generation (MW), and the market price ($/MWh) for 24 hours

Case 2: In this case, the effect of changing the ratio of critical loads β on planning results is studied. Results are represented in Tables VII and VIII. The microgrid planning solution would be the AC microgrid for all values of β. It is reasonable that by keeping α constant, there is not a shift from the AC microgrid to the DC microgrid. The impact of β, however, could be noticed on the installed generation mix. According to Table VII, when the value of β is between 0.1 and 0.7, the microgrid planning solution would install dispatchable units 3 and 4 and the solar unit. By increasing the ratio of critical loads to 0.8 and more, units 1 and 2 are also installed, and their installed capacity would increase in order to supply critical loads. It is noticeable that the fuel cell, i.e., unit 5, would not be installed for any value of β. The reason is that the capital cost of fuel cell is much higher than that of other DERs. It should be noted, however, that if the total critical load exceeds the total allowable DER capacity of available dispatchable units, the fuel cell would be installed as a last resort to ensure that critical loads would be supplied during islanding events. In other words, the supply feasibility would become a more important factor than the economy.

Similar to Case 1, the solar unit is always installed due to the coincidence of its generation pattern with the load and market price variations. According to Table VIII, the operation and reliability costs would decrease by increasing β. Increasing the ratio of critical loads would cause an increase in the total installed DER capacity, while the total load has not changed. As a result, the excess power would be sold to the main grid, which would increase the revenue of the microgrid thus decreasing the operation cost. On the other hand, by increasing the ratio of critical loads, the additional available dispatchable capacity would fully supply loads during islanding events, which causes load curtailments to decrease. Specifically, if all loads are considered as critical (associated with β=1.0), the microgrid planning solution would install more dispatchable capacity so as to fully supply all loads which causes load curtailments to reach zero in expense of a higher investment cost.

TABLE VII
INSTALLED DER CAPACITY (MW) ($\alpha = 0.40, \eta = 0.70$)

β	z	DER							
		1	2	3	4	5	6	7	Storage

									P	E
0.10- 0.70	0	0	0	3.0	3.0	0	0	2.0	0	0
0.80	0	0.40	0.40	3.0	3.0	0	0	2.0	0	0
0.90	0	0.82	0.82	3.0	3.0	0	0	2.0	0	0
1.00	0	1.25	1.25	3.0	3.0	0	0	2.0	0	0

TABLE VIII
MICROGRID COSTS ($\alpha = 0.40, \eta = 0.70$)

β	Investment Cost	Operation Cost	Reliability Cost	Total Cost
0.10-0.70	6,679,653	18,614,730	314,251	25,608,640
0.80	7,050,504	18,433,520	165,911	25,649,930
0.90	7,448,045	18,238,630	76,485	25,763,160
1.00	7,845,585	18,043,630	0	25,889,220

Case 3: In this case, the effect of changing the efficiency of inverters and rectifiers η, which are considered to be equal, on planning results is studied. Results show that changing converters efficiencies while other parameters are kept unchanged would not affect either the type of the microgrid or installed DER mix. According to Table IX, the significant impact of changing η would be on the operation and reliability costs. By increasing η, there would be less power loss in inverters and rectifiers. Therefore, the importing power from the main grid in many operation hours would decrease, which causes a reduction in the total operation cost. On the other hand, because of the reduced power loss in converters, more critical loads could be supplied by increasing the efficiency. Accordingly, there would be a reduction in the load curtailment which reduces the reliability cost. Since the installed power of all DERs is unchanged, the investment cost for different values of η would not change.

TABLE IX
MICROGRID COSTS ($\alpha = 0.40, \beta = 0.50$)

η	Investment Cost	Operation Cost	Reliability Cost	Total Cost
0.70	6,679,653	18,614,730	314,251	25,608,640
0.80		16,695,660	204,170	23,579,490
0.90		15,114,700	144,303	21,938,650
1.00		13,770,440	114,252	20,564,340

Case 4: In this case, the effect of changing the market price ρ on planning results is studied. The installed power of DERs and costs associated with different market prices are represented in Tables X and XI, respectively. By 10% decrease in the market price, the microgrid planning solution remains unchanged, except for the installed capacity of dispatchable units 3 and 4. Generally, when the market price is low, the microgrid would buy more power from the main grid, hence the exchanged power with the main grid would be positive in many hours. Therefore, the power generation of DERs would decrease in several hours, which reduces the operation cost. Increasing the market price by 10% causes the microgrid planning solution to install DERs 1 and 2 in addition to DERs 3, 4, and 7, thus the investment cost would increase. By increasing the market price by 20% or more, the microgrid should generate more power in several hours in order to supply loads, and on the other hand, it would be desirable to sell more electricity to the main grid. Therefore, all AC dispatchable units, wind generator and solar PV would be installed at their maximum capacity, and the exchanged power with the main grid would be negative in several hours. As a result, the operation cost would decrease due to the revenue from selling more power to the main grid. It is further reasonable that all critical loads be supplied by increasing the total DER capacity. Accordingly, there would not be any load curtailment, which causes the reliability cost to reach zero. Since DER generation mix is the same when there is a 20% or more increase in the market price, the investment cost would not change. Similar to previous cases, the type of the microgrid would remain the same, i.e., AC, since the ratio of DC loads is unchanged. It should be finally noted that since the capital investment cost of the fuel cell is too large, it would not be installed under any studied market prices.

TABLE X
INSTALLED DER CAPACITY (MW) ($\alpha = 0.40, \beta = 0.50, \eta = 0.70$)

Price change coef.	z	DER								
		1	2	3	4	5	6	7	Storage	
									P	E
0.9	0	0	0	2.91	2.91	0	0	2.0	0	0
Orig. price	0	0	0	3.00	3.00	0	0	2.0	0	0
1.1	0	1.23	1.23	3.00	3.00	0	0	2.0	0	0
1.2	0	5.00	5.00	3.00	3.00	0	2.0	2.0	0	0
1.3	0	5.00	5.00	3.00	3.00	0	2.0	2.0	0	0
1.4	0	5.00	5.00	3.00	3.00	0	2.0	2.0	0	0

TABLE XI
MICROGRID COSTS ($\alpha = 0.40, \beta = 0.50, \eta = 0.70$)

Price change coefficient	Investment Cost	Operation Cost	Reliability Cost	Total Cost
0.9	6,558,827	17,790,310	348,773	24,697,910
Orig. price	6,679,653	18,614,730	314,251	25,608,640
1.1	7,830,468	18,306,340	0	26,136,810
1.2	13,834,450	11,436,000	0	25,270,450
1.3	13,834,450	9,209,981	0	23,044,430
1.4	13,834,450	6,537,612	0	20,372,060

Although in proposed studies it is assumed that annual changes in load, renewable generation, and market prices are negligible, the proposed microgrid planning model has the capability to efficiently consider respective annual changes. Considering significantly small changes in the load is a practical assumption, perceivably due to the limited geographical boundaries of the microgrid which limits significant load increase as well as the increased adoption of efficiency schemes which helps with load reduction. Also renewable generation would remain the same over the planning horizon as the installed capacity will not change. The market price, however, has the highest possibility to increase. To demonstrate the impact of increase in the market price, the proposed planning problem is solved for a 2% annual increase in market prices. The total planning cost in this case is reduced to \$24,635,350 with a cost breakdown of \$9,296,503, \$15,239,520, and \$99,326 for the investment, operation, and reliability costs, respectively. Following the increase in market prices, the microgrid would be willing to sell more power to the main grid which causes a drop in the operation cost. On the other hand, in order to be able to sell more electricity the microgrid would install additional DER capacity which causes an increase in the investment cost.

Arbitrary values for DERs' allowable installation capacity were used in the proposed studies to show the effectiveness of the microgrid planning model in handling capacity limitations. If the limits are removed, the planning problem will select only the most economical candidate while ignoring all other candidates, which is not a very practical assumption. Some examples of these limitations are the rooftop solar panel installations in a community microgrid, which would be restricted by the rooftop area that can be covered by panels, and thermal unit, which cannot be installed in densely populated areas.

V. Discussions

DC microgrids could potentially improve microgrid economic benefits when the ratio of DC loads is high, and further be considered as viable alternatives to AC microgrid installations. According to the studied cases, following could be concluded:

- Among AC dispatchable generating units, those which offer a less expensive power would be installed first although they may be associated with higher capital costs.
- Among nondispatchable units, the solar unit would be installed in all cases because of the partial coincidence of its generation pattern with the market price and load variations.
- The fuel cell would not be installed in any cases since it is associated with a significantly higher investment cost compared to other DERs.
- The most decisive factor in determining the type of the microgrid is the ratio of DC loads. Changing this ratio would cause the total cost to change, so it could be used as a tool to find a critical point where DC microgrid would be more economical than the AC microgrid.
- Increasing critical loads, converters efficiency, or the market price would cause a decrease in the operation and reliability costs.
- An increase in critical loads would cause the microgrid planning solution to install more dispatchable capacity which increases the investment cost. Since the total load is unchanged, there would be an excess generated power which would be sold to the main grid, hence the operation cost would decrease. On the other hand, more critical loads would be supplied which causes a decrease in the load curtailment and the reliability cost.
- Increasing converters efficiency would cause a decrease in the power loss which on one hand decreases the importing power from the main grid in many hours, thus decreasing the total operation cost, and on the other hand, more critical loads could be supplied; hence, there would be a reduction in the load curtailment which reduces the reliability cost.
- The investment cost would change by changing the installed DER capacity. Therefore, the investment cost would remain unchanged by increasing η since the DER generation mix does not change.
- By increasing the market price, it would be desirable to install all dispatchable and nondispatchable units, except for the fuel cell, in order to sell as much power as possible to the main grid which would cause a decrease in the operation cost, and also supply all critical loads, thus decreasing the load curtailment, and accordingly, the reliability cost.

The proposed microgrid planning problem model could be further expanded to enhance practicality and computational viability. Specific areas for the future work are identified as listed in the following:

A. Uncertainty consideration

In this paper, forecasted data were used for hourly load, renewable energy, and market prices. Moreover, the islanding is considered within some specific hours in a planning year. The accurate data forecasting in microgrid planning models is a difficult task as there are various uncertainties in the planning data. In other words, there is an error associated with all forecasted values. Uncertainty considerations could potentially alter the microgrid planning results. This issue has been studied in the literature [14]. Similar methods can be applied here to expand the microgrid planning problem and make a more accurate decision between AC and DC microgrid installations.

B. Computational complexity

The type of the microgrid and DER generation mix in the proposed microgrid planning model are determined in an integrated fashion by solving a single optimization problem. This problem, however, is large-scale and nonconvex. A decomposition method could be employed in this case to convert the problem into a set of smaller and easier to solve, yet coordinated, subproblems. The application of decomposition methods in solving large-scale planning problems is extensively discussed in the literature and can be directly used here. A suggested decomposition for the proposed microgrid planning problem would include a long-term investment master problem, a short-term operation subproblem, and a reliability subproblem. The investment plan obtained in the master problem will be examined in subproblems to find optimal DER schedule as well as desired levels of reliability. The final solution would be obtained in an iterative fashion.

VI. Conclusions

Among different categories of microgrids, i.e., AC, DC and hybrid, extensive research has been conducted in the operation and control of AC microgrids. DC microgrids could however offer several advantages compared to AC microgrids: providing a more efficiently supply of DC loads and reducing losses due to the reduction of multiple converters used for DC loads, easier integration of DC DERs, and eliminating the need for synchronizing generators. In this paper, different components of AC and DC microgrids were explained, followed by developing a microgrid planning model with the objective of determining the optimal DER generation mix and the type of the microgrid, i.e., either AC or DC. It was shown that this model was able to identify threshold ratios of DC loads which made the DC microgrid a more economically viable solution than the AC microgrid. In other words, for ratios smaller than the threshold ratio, AC microgrid would be more economical and for ratios larger than that, DC microgrid would be more economical. The problem objective was to minimize the total planning cost subject to prevailing planning and operation constraints, and was formulated using mixed-integer programming. Numerical results were presented to analyze the impact of the ratio of DC loads, the ratio of critical loads, converters efficiency, and market price on microgrid planning solutions. It was verified that the decisive factor in determining the type of the microgrid would be the ratio of DC loads. In other words, if other parameters changed except for the ratio of DC loads, the type of the microgrid would not change. It was also shown that increasing the ratio of critical loads would increase the total installed dispatchable generation capacity. Finally, it was demonstrated that changing critical loads, converters efficiency, or the market price, would significantly affect the operation and reliability costs.

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