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Economic and Environmental Policy Analysis for Emission-Neutral Multi-Carrier Microgrid Deployment

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HIGHLIGHTS

- The decision-making framework streamlines emission-neutral microgrid deployment.
- A novel price-based demand shifting technique is developed to contribute energy savings.
- A decomposition approach is employed to decouple the investment and operation problems.
- Challenges and solution schemes for emission-neutral microgrids are discussed.
- Financial feasibility of microgrid projects with green resources is explored and verified.

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Demand response
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ABSTRACT

Energy and global climate change crises are correlated issues since energy generation currently contributes to nearly 40% of global greenhouse gas emissions, and inevitably the escalating energy demand realization exacerbates the ongoing undesirable circumstances. As a viable solution against the concerns above, microgrid deployments with low-emission on-site resources have been receiving increasing attention from power decision-makers. Thus, this study scrutinizes the technical and financial sustainability of deploying a net-zero emission multi-carrier microgrid and determines the optimal generation configurations. Besides, the proposed emission-neutral multi-carrier microgrid model provides insights into the economic prominence of renewable energy incentives together with regulations for the short-term deployment of green resources. The objective of the proposed model is to minimize the multi-carrier microgrid deployment costs associated with the investment, operation, maintenance, energy demand shifting, monthly peak demand charge, emission, and reliability. Furthermore, load prioritization and a novel demand shifting of demand response schemes are propounded to maintain at least the continuous flow of energy for high-prioritized loads. The customer multi-carrier microgrid deployment problem is disintegrated into an investment master problem and an operation subproblem. The results indicate that notable electrical peak mitigation of about 7–23% is procured by employing the demand response scheme. Furthermore, the sensitivity analysis illustrates that renewable penetration of 30% along with dispatchable resources is required to procure the targeted share of green resources within microgrids. Finally, the economic and environmental merits of the proposed emission-neutral multi-carrier microgrid are ensured with savings and the discounted payback period of 131% and 3.977 years, respectively.

1. Introduction

With the gradual depletion of fossil fuels and its devastating effects on the environment, an international treaty for reaching a net-zero emission (NZE) system in the second half of the 20th century was committed (Kyoto Protocol) to stabilize the increase in global average temperature below 2 °C and pursue an effort to keep the temperature at 1.5 °C [1,2]. Microgrids (MGs), as an alternative system in place of conventional large-scale power plants emitting the largest share of greenhouse gas (GHG) emissions, are envisioned to exploit modern technologies to surmount the obstacle by the on-site installation of distributed energy resources (DERs) in the proximity to the energy utility facilities and/or electricity consumers' premises [3,4]. On the other hand, the current policy is motivating MGs' investors to widely deploy natural gas-fired technologies to underpin the most robust

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Nomenclature

Indices

AB index for auxiliary boiler unit
c index for candidate units
chp index for combined heat and power unit
d index for days
e index for electricity
ESS index for electrical storage system
h index for hours
l index for carrier comprising {e,t}
m index for months
n index for types of customers comprising {residential, commercial, industrial}
p index for produced emission {CO_2, SO_2, and NO_2}
pv index for photovoltaic unit
s index for scenario
t index for heat
$trans$ index for transformer unit
TSS index for thermal storage system
u index for units
wt index for wind turbine unit
y index for years

Sets

DER set of distributed energy resources comprising {DG,SS}
DG set of distributed generation/transformer units
SS set of storage system units comprising {ESS,TSS}

Parameters

a, b, c, d, e, g coefficients of fuel consumption function of CHP
ACo annualized energy/power rating capital cost of units ($/year)
AV availability of units (%)
Co capital cost of units ($)
D total demand (kWh)
DOD depth of discharge
EF emission factor of pollutants
EL project lifetime
i discount rate
LPF load participation factor for shifting up/down the energy demand (kWh)
$Mbig$ a sufficient large number
N total number
$P(\partial_s^{irradiation/wind})$ power produced by PV/WT units as a function of irradiation/wind speed
$P_{chp}^{l(*)}$ feasible operating regions of CHP for various marginal points comprising $* \in \{A, B, C, D\}$
P^{Max} installed DER capacity (kW)
P^{Min} minimum power of DER (kW)
R^{target} DER available online reserve
RM required online reserve percentage of the critical demand at each interval
SOC^{Max} installed energy storage capacity (kWh)
Y^{com} commissioning year of the units
$\pi^{deg,l}$ cost for energy storage degradation ($/kWh)
π_p^{em} penalty related to pollutant p
$\pi_n^{ens,l}$ value of lost load for customer type n ($/kWh)
$\pi^{Net,g}$ natural gas price ($/kWh)
$\pi^{Netpur/sale,e}$ hourly electricity purchase/sale price ($/kWh)
π^{trans} price for maximum peak demand in a given month ($/kW. month)
ω coefficient of present-worth value
$\alpha^{char/disch}$ charge and discharge efficiency of SS charge controller
α^{ef} efficiency of units
$\alpha^{ef,converter}$ efficiency of ac-to-ac converter for WT unit
$\alpha^{ef,inverter}$ efficiency of dc-to-ac inverter for PV unit
α^{loss} energy loss coefficient of SS
α^{main} maintenance cost coefficient of units
ζ incentive coefficient of renewable energy penetration
κ normalized generation forecast of nondispatchable *DGs*

Variables

CC contracted power (peak demand) cost ($)
$D^{shup/shdo}$ shifted up/down energy demand by demand response (kWh)
DC energy storage degradation cost ($)
EC microgrid total emission cost ($)
ELF equivalent loss factor
I installation state of DER units {0/1}
$IS^{shup/shdo}$ shifting up/down state of the energy demand {0/1}
IC microgrid total investment cost ($)
MC microgrid total maintenance cost ($)
NZE net-zero emission (kg/year)
OC microgrid total operating cost ($)
OF objective function
P_u generated/transformed energy by units to feed customers (kWh)
P^R storage system rated power (kW)
$P^{char/disch}$ charge/discharge of SS (kWh)
P^{ens} energy not supplied (kWh)
P^{loss} energy loss of SS (kWh)
$P^{Net,g}$ purchased gas from local gas distribution network (kWh)
$P^{Netpur/sale,e}$ purchased or sold electricity from/to the network (kWh)
$P_{trans}^{in/out}$ transformed electricity by bidirectional transformer (kWh)
SC total energy demand shifting payments ($)
SOC state of charge of energy storage system (kWh)
UC microgrid unserved energy cost ($)
V binary variable for hourly commitment status of installed units
$\pi_h^{shifting,l}$ hourly local price of energy demand shifting ($/kWh)
υ natural gas consumption by gas-fired units

Acronyms

CRF capital recovery factor
DPP discounted payback period
DRP demand response program
GHG greenhouse gas
LCOE Levelized Cost of Energy
LEP local energy price
MCMG multi-carrier microgrid
MCPP microgrid conventional power penetration metric
MG microgrid
MINLP mixed-integer nonlinear programming
NZE net-zero emission
REP renewable energy penetration metric
RER renewable energy resource
VOLL value of lost load

business cases in place of renewable energy resources (RERs) [5]. This finding contrasts sharply with the most policy framework advocacy for achieving deep cuts in GHG emissions due to the extensive penetration of small-scale sources of gas-based carbon emitters. Thus, there are many obstacles and challenges in implementing and operating MGs that need to be investigated in terms of economic and environmental sustainability for procuring an emission-neutral system.

Microgrid deployment is receiving a great deal of attention so that a rational design is an important premise for the stable and efficient operation of such systems. Abundant works have been published in the pertinent literature investigating MGs design under different circumstances. A typical MG will most likely be owned by a community or small group of public and private sectors. Various resources contribute to economic benefits of MGs such as high energy efficiency, less expensive on-site generation in conjunction with storage systems, reliability improvement obtained through islanding capability, and consumers' participation in demand response programs (DRPs) as a means to reduce energy costs [6,7]. MGs can also operate in islanded mode and sustain the power supply during the grid disturbance as well as preventing massive investment in generation and transmission [8]. An algorithm for co-optimization of large generating units, transmission lines, and MG deployments is proposed to procure the least operation, planning, and reliability costs [9]. The numerical simulations declare that MG expansions can provide significant reliability and economic benefits in the power system in lieu of large investments in new generation and transmission facilities. An MG co-optimization generation and distribution planning model is proposed to determine the optimal DER generation mix and upgrade the network by building new lines [10]. A game-theoretical approach for sub-transmission and generation expansion planning is presented in the presence of multiple regional energy systems [11]. A fuzzy satisfying method accompanied by an evolutionary-based stability state technique is used to realize the Pareto optimality. The optimal structural design of a community MG with industrial and residential customers is achieved and solved by using the adaptive nesting evolutionary algorithm to cope with the vast space of search range [12]. Herein, wind turbine (WT) and photovoltaic (PV) units in conjunction with an electrochemical battery are deployed to supply MG's customers. Financial feasibility evaluation of MG deployments is analyzed considering both pre-tax and after-tax cash flows [13,14,15]. Various incentive schemes for penetration of grid-connected PV-electrical storage system (ESS) MGs are incorporated in the model. Optimal planning strategies for powering communities with PV systems are investigated to evaluate the efficacy of the government's incentive mechanisms as a means of determining whether the PV-powered community MG is inducible in a specific area with distinct solar radiation intensity and incentive policy [16]. Various business cases for isolated and grid-connected MGs, as well as methodologies and applications, are reviewed in [17]. It is declared that the implementation of MGs would result in over 30% savings to potential stakeholders. A two-stage optimization framework for optimal design and operation of urban and remote community MGs is presented in a deregulated environment [18]. The retail energy market model of the proposed MG is investigated to increase the third-party investment in the local energy system. The objective of the proposed market model is to minimize the daily operating cost of the community while maximizing the benefits of all investors. The impact of various ancillary service provisions in MG sizing is scrutinized to gain higher revenue streams for MG's stakeholders [19]. The results suggest that MG's participation in ancillary service markets has only little impact on the optimal DER portfolios, but, for all that, the stakeholders gain financial revenues from participating in such markets. The impact of location and load shapes on MG design in grid-connected mode is studied to uninterruptedly supply both electrical and thermal demands over a planning horizon of 20 years [20].

The increase in the number of DERs and MGs can potentially result in significant uncertainty in the system due to large fluctuations and probable behaviors of demand- and supply-side assets, which would have adverse effects on the stability of the power system performance. A potential solution for this downside is the joint installation of dispatchable and nondispatchable distributed generations (DGs) along with ESSs [21,22]. A variety of ESS technologies with different characteristics can be used to improve the reliability and reduce the operation cost of MGs [23]. Optimal sizing of ESSs within interconnected MGs is acquired using a bi-level optimization technique [24]. The upper-level problem determines the optimal ESS sizing while the lower-level schedules the operation optimization under various operating scenarios, i.e., normal operation, typical and extreme faults. A cooperative generation planning model for interconnected MGs is proposed [25], in which both the long-term investment and the short-term operation costs are included in the model. Nash bargaining is incorporated to stimulate cooperation among urban buildings. A bi-level model for an interconnected MG power and reserve capacity planning problem is proposed [26]. The upper-level problem is designed to minimize the planning and operational cost of MGs. The reliable supply of power by the distribution system operator is ensured in the lower-level problem. A stochastic multi-objective framework for dynamic planning of interconnected MGs is proposed considering economic, reliability, technical, and environmental aspects [27]. In the proposed approach, optimal site, size, type, and commissioning year of DERs are determined along with the optimal allocation of section switches to partition conventional distribution system into several interconnected MGs. The proposed framework is considered as two single objective functions in which the first objective minimizes the costs of investment, operation, maintenance, power loss, and emission, and the second objective minimizes the load curtailments in both connected and islanded modes of MGs. Moreover, three different strategies based on risk-seeker, risk-neutral, and risk-averse are defined for the distribution network operator by the fuzzy satisfying method. A mixed-integer linear programming model for optimal integrated deployment of interconnected multi-carrier MGs (MCMGs) is presented [28]. The limitations of electrical and heat transfer networks are considered between MCMGs to allow for optimal operational and structural design of DER technology placements in the interconnected MCMGs.

The uncertain parameters that the power system faces are reviewed in [29]. A theoretical framework to study the cooperative planning of RERs within interconnected MGs is proposed using the realistic meteorological data [30]. The proposed framework considers self-interested behaviors of MGs, along with uncertain behaviors of RERs over the planning horizon. The results indicate that the system's cost can be reduced by 35.9% compared with the non-cooperative planning framework. MG's design under uncertainties of RERs, demands, electricity market price, and islanding incidents is explored to inspect whether the profits would compensate for the investment expenditure of the DER formations [31]. To account for uncertain data, a robust optimization model is adopted. The solution to the MG planning problem is addressed by splitting the problem down into an investment master problem and an operation subproblem. An advanced model for dynamic and multi-stage capacity expansion planning in a grid-connected MG integrated with electric vehicle charging stations, and various DERs is presented [32]. Uncertainty intervals are employed to describe the short-term uncertainties of demands and renewable generation. The autocorrelation approach based on the actual data is utilized to simulate the uncertain behavior of RERs and demands in MG environments [33]. A multi-period joint expansion planning approach for an MCMG is developed to determine the portfolio of DGs and their commissioning years [34]. The long-term declining trend uncertainty of ESS investment cost is dealt with the information gap decision-based planning model. In contrast, the short-term uncertainty involving the randomness of renewable generation and the variability of demands is coped with the chance-constrained method in the paper. An innovative two-stage stochastic programming method is proposed to optimally select and size various DERs for a military-based MG considering both economic benefits and resilience performance [35]. The proposed method explicitly models the interaction between DER sizing at the planning stage and hourly or sub-hourly MG dispatch at the operating stage in both grid-connected and island modes considering uncertainties in grid disturbance, load, and renewable generation. It is shown that the optimal sizing results are more sensitive to tariff and discount rates than survivability level. An efficient model for isolated MGs deployment is proposed to obtain the least planning costs comprising the DERs investment, electronic converters, and operations of the resultant MG [36]. The optimum combination, position, and scale of DERs in an autonomous MG is assessed under multiple uncertainties [37]. The papers in [38,39] address practical MG expansion planning problems in a competitive electricity market to assist community MG companies in deciding whether or not to invest in MG installations. A three-layer algorithm is applied in the developed model to account for effective and coordinated long-term planning of three power companies (community MG, generation, and transmission companies). The model ensures the economic viability and safe operation of the power system under uncertainties of load growth and component outages while keeping an acceptable level of reliability in the system.

Demand response programs are useful options to cope with the uncertainty of renewable generations. Generally, DRPs are classified into two major categories, namely time- and incentive-based programs. Time- and incentive-based DRPs and several sub-groups are described comprehensively in [40]. In [41], DRP under real-time pricing scheme is employed to motivate the consumers to change their electricity consumption patterns (considering load shifting and curtailment options) in response to price fluctuations. The impacts of demand response participation rate and value of lost load on MG reliability and economy indices are measured in the model. The results indicate that the energy curtailment decreases by higher participation of responsive customers, which ultimately results in lower conditional value-at-risk. Seeking for operational improvements, different price-based DRPs in company with interruptible load programs are regarded in [42]. Herein, the loads are divided into four different categories as interruptible, adjustable, shiftable, and fixed loads. A novel metaheuristic optimization method for optimal sizing of a stand-alone MG is developed incorporating direct load control DRP to flatten the load curve [43]. The reliability of the power supply for remote communities is guaranteed in the model by satisfying the reliability index. A novel method based on the Markov model incorporating the interior-point algorithm is presented to determine the optimal sizing of PV panel and WT generator in a community MG considering time-based DRP [44]. Moreover, the Markov model based on the fuzzy c-means is employed to acquire the states of PV and WT units, air temperature, and inelastic demand. The joint multi-objective optimization of MG design and operation with the employment of an effective DRP model is represented to accomplish the goal of cost reduction without compromising customer satisfaction [45]. To reduce the resource needed in solving the complex planning model, a maximum fuzzy satisfaction method is adopted to convert the multi-objective problem into a single combined objective. The profit of both flexible and inflexible customers are increased using a novel dynamic pricing scheme, which is calculated based on the amounts of RER generations and main grid energy imports [46]. The proposed dynamic pricing scheme can be exemplified as plug and play devices because of its easy implementation in present market structure without any modification.

The prior works are focused on ac MG planning, whereas hybrid ac/dc MGs are not addressed as the combined ac/dc configuration allows different loads and DERs to connect with the minimum need for electrical conversion. An MG planning model for ascertaining the ideal size of DERs along with feeder's type (ac or dc) is proposed from economic and reliability perspectives [47]. The influence of dc loads percentage, as well as converters costs and efficiencies on the planning solution, is further explored in the model. At last, it is shown that the model can identify threshold ratios of dc loads, which make the dc MG a more economically viable alternative than of ac MG. However, the model does not offer the capability of a joint hybrid ac/dc MG and accordingly opts one type of MG. An extended work of the previous publication is modeled in [48], which considers a combination of both ac and dc buses as a hybrid MG planning. The main drawback of the proposed model is that it is solved only in one shot. In [49], a model for the efficient design of a hybrid ac/dc MG with DER combination is represented to guarantee the least planning costs. The model determines the type of each feeder and, after that, sites the appropriate DERs in each appointed feeder. A comprehensive model of the previous works is proposed, which determines the optimal ESS sizing and sitting within a hybrid ac/dc MG [50]. The results validate the economic prominence of MGs with hybrid ac/dc feeders compared to MGs with individual ac or dc feeders. Active load participation in a holistic MG planning model is assessed to find the optimal size and location of ESSs [51].

Microgrid and energy hub systems propound and share some identical features in the modeling of future energy systems. Thus, energy hub-related works can help and contribute to the development and modeling of MG systems. The long-term planning of DERs and electric transmission networks is performed in an energy hub system, taking into account the exact models of electricity and natural gas networks [52]. A notable emission reduction is acquired by accurate modeling of energy transmission networks in the model. Combined heat and power (CHP)-based MGs design and operation under security constraints are presented in [53]. The supply reliability of the system against N-1 power generator contingencies is assured by determining the optimal power reserve. The economic analysis of a combined cooling, heating, and power system is studied under multiple uncertainties [54]. The economic feasibility of the model is scrutinized by assessing the impacts of economic parameters on the system's profitability. Technologies that can curb GHG emissions and an overview of the assessment of carbon emissions in a commercial building are discussed in [55]. The results indicate that the optimal determination of CHP size and technology, along with RERs, provides a greener option for the region. Thus, CHP systems, together with RERs, are the core components in clean energy systems of the future. Besides, the eminence of CHP systems along with RERs would be ignited as a substantial unit in response to RER fluctuations.

The benefits of MGs are not only economical but also environmental by erecting low-carbon communities. An optimal stochastic deployment is provided concerning the size and type of DGs within an MG [56]. The model is solved using a multi-objective genetic algorithm to concurrently minimize the total planning (capital and operational costs) and carbon dioxide (CO_2) emission costs. In addition, the uncertainty and intermittency associated with RERs are dispelled by the installation of electrical and thermal storage systems within the MG. A multi-objective optimization model for robust MG planning is developed under multiple uncertain factors [57]. The results of applying the model to an industrial park in Taiwan reveal a drastic reduction of the expected annual CO_2 emission and carbon tax by roughly half of the region's existing utilities. The main aim of the work is to provide an efficient strategic planning solution for the stakeholders at the budgeting phase. A technique for the configuration of RERs in a power distribution system is presented for net-zero energy MG applications [58]. The total annual CO_2 emission and energy costs are estimated by the DER Consumer Adoption model. The optimal design of an emission-neutral MG is acquired with the goal of minimizing the total expansion planning costs over the planning horizon [59]. Globally, the building sector as an example of real-world MG is considered as one of the most dominant sources of GHG emissions, eventuating for about a third of the global energy consumption and its associated GHG emissions [60]. The impact of PV system design on the balance of GHG emissions in an emission-neutral building is analyzed [61]. The formulation and concept in the paper share the same characteristics with MGs design problems. An emission allowance market model for integrating MGs with conventional generation units and transmission lines is presented to provide an efficient policymaking tool for achieving the desired reduction in emissions through increasing

RER's penetrations [62]. In the proposed model, a regional emission constraint is introduced as a tool for achieving an acceptable level of emission in the power system. Research on the potential reduction of CO_2 emissions is conducted by deploying ESSs to a combined power generation unit with an organic Rankine cycle [63]. The results indicate that the system's potential for saving CO_2 emissions is directly proportional to the ratio of the conversion factor for CO_2 emission and system location. It is also reported that the use of carbon credits could turn an unattractive project from an environmental perspective into a project that not only saves costs but also offsets the total emissions from facilities. An analysis is conducted to explore the viability of running a carbon-free supply chain by integrating on-site WT and PV units with the goal of minimizing RERs' Levelized cost [64]. "The Levelized Cost of Energy (LCOE) is a metric to measure the expense of producing one Megawatt-hour of electricity given from different generation technologies." Renewable energy utilization, along with various energy policies, needs to be targeted concurrently to achieve an NZE system by a particular year. Techno-economic design analysis of a nanogrid system as a scaled-down MG is studied to serve the daily demand of a residential building in the Savannah region [65]. The proposed system has achieved a moderately lower emission ton per year as compared to the case without nanogrid deployment. The potential for adoption of a small-scale MG is assessed in terms of both economic feasibility and environmental sustainability [66]. The proposed model determines the configurations with the lowest LCOE and examines the economies of scale impact on LCOE and CO_2 emissions. An MG deployment is analyzed in terms of economic and environmental sustainability [67]. The economic and environmental performances of the deployed MG is evaluated by the proposed energy management strategy in terms of LCOE and produced/avoided CO_2 emissions. An economic and technological solution for rural electrification of a village with high renewable penetration is acquired to minimize the overall deployment cost and abate CO_2 emissions from the electricity sector [68]. Besides, the DRP strategy is incorporated in the model to obtain lower LCOE by shifting low-prioritized loads towards the availability of solar irradiance. The results advocate that the least-cost operation of the system can be procured by enabling the battery charge controller to charge batteries at all rates. Optimal renewable resource planning of a stand-alone dc MG for rural and urban applications is studied to alleviate the LCOE [69]. The results advocate that such a system can operate at an energy cost of \$0.27 in islanded mode, whereas the cost of energy would drop to \$0.163 in case of partial connectivity to the utility network. The Grasshopper optimization algorithm is utilized to determine the optimal and reliable system configuration of an off-grid community MG with the aim of minimizing the LCOE and deficiency of power supply probability [70]. The efficacy of the proposed algorithm is verified as compared to its counterparts, i.e., cuckoo search optimization and particle swarm optimization algorithms. In [71], the optimal configuration of a real MCMG is studied under different carbon emission reduction and renewable energy penetration constraints to provide general guidance for the expansion of low-carbon districts. The results advocate that carbon emission cut and renewable penetration realizations are case-sensitive, which require site-specific policies in order to deploy low-carbon districts.

However, far too little attention has hitherto been paid to the optimal deployment of NZE-based MCMGs to procure the targeted level of at least 32% share for renewable energy penetrations in the European Union by 2030 [72,73]. Thus, this paper represents a model for ensuring the financial feasibility of a customer MCMG deployment as well as performing sensitivity analysis on renewable energy incentives for accomplishing the NZE network with requisite penetration of RERs. The DER mix under study is comprised of the bidirectional distribution transformer, CHP, auxiliary boiler, PV, WT, and storage systems. Furthermore, an exact electrical and heat modeling of CHP units is modeled regarding feasible operation region; so that electrical and thermal efficiencies of the pinpointed CHP unit are not constant and vary with the operation points. The proposed model also enables the customer MCMG to operate in the islanded mode and adequately supply at least the high-prioritized local loads by on-site pinpointed DERs in the event of grid outages. More importantly, a novel demand shifting technique based on the local energy price (LEP) concept is developed to contribute energy savings for customers by shifting their demands to off-peak hours. Overall, the multi-objective planning problem aims at ensuring the economic viability of MCMG deployments (costs pertain to the investment, operation, maintenance, energy demand shifting, monthly peak demand charge, energy storage degradation, emission, and reliability), while targeted reliability, online reserve, and NZE constraints are satisfied. Each year's chronological electrical and thermal load curves are classified as two typical days and two typical six months to burden the complexity of the computations. In the interest of lower recompensation stemmed from the annual islanding incidents, the distinct value of lost loads for different community customers is presumed in this study to boot. Ultimately, the proposed model is solved using a decomposition method that unites the genetic algorithm of MATLAB and mixed-integer nonlinear programming (MINLP) model of GAMS software. In short, the overarching contributions of the paper are summarized as follows:

- Determining the optimal type, size, and commissioning year of the DERs mixture from economic, reliability, and environmental perspectives.
- Scrutinizing the financial feasibility of the MCMG deployment in terms of various economic measures such as present-worth value, discounted payback period, and savings.
- Investigating the impacts of RER incentives together with NZE regulation on renewable energy penetrations to procure the targeted share of green generations, and consequently, an emission-neutral system as a quick and viable solution against the current global climate change crisis.
- Proposing a novel demand shifting technique based on the LEP concept, which is a metric to measure the expense of producing one kilowatt-hour of energy given from different pinpointed generation technologies.
- Regarding the heat-power dual dependency characteristic in CHP units as the central core of the proposed customer MCMG, which satisfies both thermal and electrical energy requirements at a lower cost.
- Load priority with distinctive penalty cost of load curtailment for the residential, commercial, and industrial customers within the community is considered as a viable option to feed leastways high-prioritized local loads during sudden power grid disruptions.
- Using a decomposition approach to turn the planning problem into a long-term investment master problem and a short-term operation subproblem, taking into consideration the reliability, online reserve, and NZE constraints.

2. Multi-carrier microgrid planning problem model outline

Microgrid DERs require a higher investment cost compared to conventional energy resources. Nevertheless, DERs could provide economic, reliable, and environmental benefits compared to the energy purchased from the utility grid, particularly during peaks or at the times of any utility network outage. The salient feature of an MG is its islanding capability and consequently, survivability of high-prioritized local loads supplied by on-site DERs in the presence of any faults, disturbance, or voltage fluctuations in the electric utility network. MGs can purchase electricity and natural gas from the local utility company, identified with positive exchange power, or sell the extra electricity to the local utility company or adjacent MGs, identified with negative exchange power.

In this paper, both dispatchable and nondispachable DGs are considered for the MCMG deployment. The only drawback of renewable

DGs is their nondispatchability to guarantee an economic and reliable supply of loads in grid-connected and islanded operation modes. The obstacle can be surmounted by coupling RERs with appropriate dispatchable DGs, along with DRPs and storage systems. Not only are storage systems cost-saving by enabling energy arbitrage, but also they enhance the level of reliability during islanding incidents [74]. An MCMG may include various DERs owned by multiple stakeholders as well as several customers with different sensitive loads such as residential, commercial, and industrial [18]. However, in this study, DERs are assumed aggregated with multiple stakeholders to ensure the economic viability of the customer MCMG with the appropriate installation of the available DERs during the planning horizon. Here, local customers of the community are the only stakeholders who own and run their utilities. Likewise, customers with different sensitive loads are prioritized with distinct penalty costs in order to ensure a reliable continuous service for the most critical local loads in the events of any utility disruption [75]. Herein, the smart grid technologies embrace distribution transformer (bidirectional mutual voltage converter), CHP, auxiliary boiler (AB), PV unit, WT unit, electrical and thermal storage systems (ESS and TSS), and elastic and nonelastic loads as demand-side resources. The phase-change thermal storage unit of reference [76] is employed as TSS in this paper.

This work performs the long-term investment and short-term operation of a small-scale energy zone in Kashan city, Iran, for ensuring the economic viability of a customer MCMG with multiple stakeholders while checking the reliability, online reserve, and NZE constraints. Fig. 1 depicts the simulation procedure of the proposed MCMG planning model. The decomposition approach is shown in Fig. 1, coordinating the

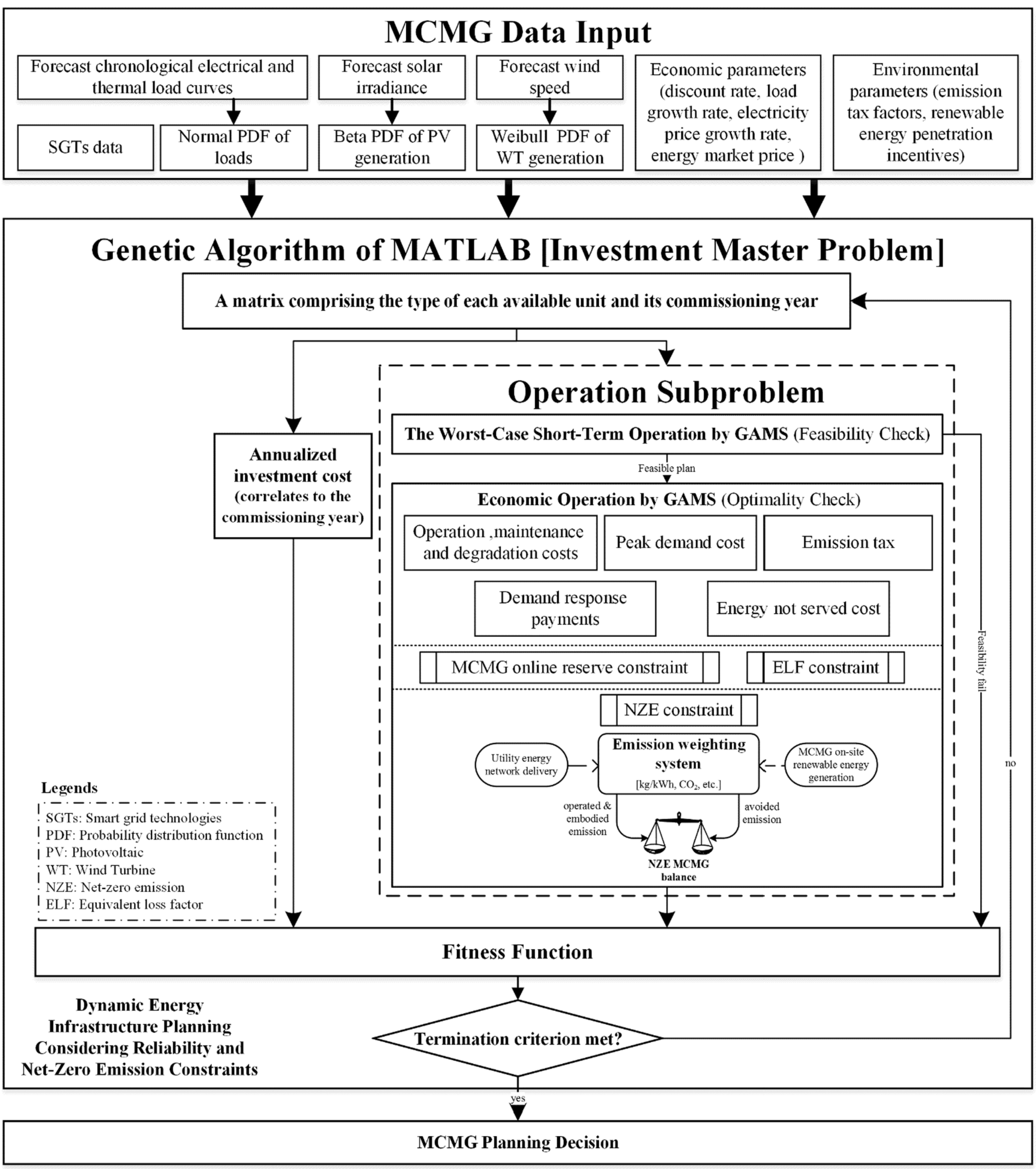


Fig. 1. Proposed multi-carrier microgrid deployment model.

investment master problem and the operation subproblem as part of the optimization scheme. First of all, the input data are processed to form the preliminary parameters of the system. The investment master problem ascertains the best candidates among the available DERs with their associated commissioning years using the genetic algorithm of MATLAB with fourteen genes. The investment plan is employed in the operation subproblem for finding the optimal energy scheduling of installed DERs under prevailing uncertainties while checking the targeted reliability, online reserve, and NZE constraints using ANTIGONE solver of GAMS. After the objective function of each chromosome is acquired, its respective fitness value is calculated. For each chromosome, the fitness value is penalized if the feasibility or optimality check fails. Then, the population is sequentially sorted out from the lowest to the highest in each iteration. If the best population is converged, the algorithm terminates. Otherwise, the iterative process will proceed until a secure and desirable planning schedule is acquired over the planning horizon.

3. Multi-carrier microgrid planning problem formulation

The objective of the MCMG planning problem is to minimize the total planning cost (1a), which constitutes the present-worth costs pertained to the DERs investment, operation, maintenance, energy demand shifting, contracted power between the community customers and local utility company, energy storage degradation, emission (CO_2, SO_2, and NO_2), and reliability. Eqs. (1b)–(1j) define cost terms used in the objective function.

$$Minimization: OF = IC + OC + MC + SC + CC + DC + EC + UC \tag{1a}$$

The investment cost (1b) evaluates the annual capital cost of the installed DERs multiplied by the capital recovery factor (CRF). The annualized DERs' capital cost (1c) is derived from the total DERs' capital cost on the basis of present-worth value, which correlates to the commissioning year of the selected DERs in the planning horizon.

$$IC = CRF^{EL} \cdot \sum_{y} \sum_{u \in DER} \sum_{c} ACo_{uc} \cdot I_{ucy} \tag{1b}$$

$$ACo_{uc} = Co_{uc} \cdot \omega_{iy} \forall y = Y_u^{com} \tag{1c}$$

The operation cost (1d) consists of two terms, the cost of power exchanged with the utility company calculated by electricity market price times the amount of exchanged power with the electric utility company, and the cost of purchased natural gas for gas-fired units calculated by natural gas price times the amount of purchased gas from the gas utility company. The maintenance cost of the installed DGs is given in (1e), which expresses the power generation of the pinpointed units times their associated maintenance coefficients in $/kWh.

$$OC = \frac{1}{N_s} \sum_{s} \sum_{y} \sum_{m} \sum_{d} \sum_{h} \omega_{iy} \cdot \left[+ P_{ymdhs}^{Netpur/sale,e} \cdot \pi_{ymdhs}^{Netpur/sale,e} + P_{ymdhs}^{Net,g} \cdot \pi_{ymdh}^{Net,g} \right] \tag{1d}$$

$$MC = \frac{1}{N_s} \sum_{s} \sum_{y} \sum_{m} \sum_{d} \sum_{h} \omega_{iy} \cdot \left[\sum_{u \in DG} \sum_{c} P_{uymdhs} \cdot \alpha_{uc}^{main} \cdot I_{uyc} \right] \tag{1e}$$

The energy demand shifting cost (1f) denotes the energy demand shifting up or down for different types of customers multiplied by local energy demand shifting price.

$$SC = \frac{1}{N_s} \sum_{s} \sum_{y} \sum_{m} \sum_{d} \sum_{h} \omega_{iy} \cdot \left[\pi_{ymdhs}^{shifting,l} \cdot \sum_{n} \left(D_{ymdhsn}^{shup,l} + D_{ymdhsn}^{shdo,l} \right) \right] \forall l \in \{e,t\} \tag{1f}$$

The monthly contracted power charge (a fixed monthly charge) between the user and the utility company for the installed transformer is modeled in (1g). The energy storage degradation cost is formulated as (1h).

$$CC = \sum_{y} \sum_{m} \omega_{iy} \cdot \sum_{c} P_{trans,c} \cdot \pi^{trans} \cdot I_{trans,yc} \tag{1g}$$

$$DC = \frac{1}{N_s} \sum_{s} \sum_{y} \sum_{m} \sum_{d} \sum_{h} \omega_{iy} \cdot \sum_{u \in SS} \pi^{deg} \cdot \left(\left| P_{uymdhs}^{char/disch} \right| \cdot \alpha_u^{ef} \cdot I_{uyc} \right) \tag{1h}$$

The emission penalty is a cost imposed by regulators to curb emissions. The emission function cost for the utility grid and other generation units is calculated in (1i). The reliability cost (1j) represents the cost of unserved energy for compensating curtailed customers, which is interpreted as the value of lost load (VOLL) for different types of customers multiplied by the sum of different users' hourly load curtailments.

$$EC = \frac{1}{N_s} \sum_{s} \sum_{y} \sum_{m} \sum_{d} \sum_{h} \omega_{iy} \cdot \sum_{p} \sum_{u \in DG} \sum_{c} \pi_p^{em} \cdot \left(P_{uymdhs} \cdot I_{uyc} \cdot EF_{up} \right) \tag{1i}$$

$$UC = \frac{1}{N_s} \sum_{s} \sum_{y} \sum_{m} \sum_{d} \sum_{h} \sum_{n} \omega_{iy} \cdot \pi_n^{ens,l} \cdot P_{ymdhsn}^{ens,l} \forall l \in \{e,t\} \tag{1j}$$

Eqs. (2a) and (2b) denote the present-worth value and capital recovery factors, respectively.

$$\omega_{iy} = 1/(1+i)^{y-1} \tag{2a}$$

$$CRF^{EL} = i \cdot (1+i)^{EL} / ((1+i)^{EL} - 1) \tag{2b}$$

The MCMG planning project is bound to deployment and commissioning year constraints. It is presumed in this paper that the microgrid developer can install either one candidate for each set or none as (3a). The candidate DERs will be commissioned once the planning and the engineering design are completed (3b). Once a candidate DER is installed, its investment state will be fixed at 1 for the remaining years in the planning horizon (3c).

$$\sum_{y} \sum_{c} I_{ucy} \leqslant 1 \forall u \in DER \tag{3a}$$

$$I_{ucy} = 0 \forall u \in DER, \forall y < Y_u^{com} \tag{3b}$$

$$I_{uc(y-1)} \leqslant I_{ucy} \forall u \in DER \tag{3c}$$

The electrical demand balance Eq. (4a) ensures that the power generation/conversion by DERs (dispatchable and nondispatchable units and ESS) plus the exchanged power with the electric utility network at the point of common coupling matches the hourly electrical demand of all types of customers regarding the demand shifting capability minus the amount of curtailed electricity demand for different customers. Similarly, the thermal demand balance Eq. (4b) ensures that the produced/converted thermal energy by DERs (dispatchable units and TSS) equates to the hourly heat demand of all types of customers considering demand shifting capability minus the amount of curtailed heat demand for different customers.

$$\sum_{n} \left(D_{ymdhsn}^{e} + D_{ymdhsn}^{shup,e} - D_{ymdhsn}^{shdo,e} - P_{ymdhsn}^{ens,e} \right) = P_{trans,ymdhs}^{in/out} + P_{chp,ymdhs}^{e} + P_{pv,ymdhs} + P_{wt,ymdhs} + P_{ESS,ymdhs}^{char/disch} \tag{4a}$$

$$\sum_{n} \left(D_{ymdhsn}^{t} + D_{ymdhsn}^{shup,t} - D_{ymdhsn}^{shdo,t} - P_{ymdhsn}^{ens,t} \right) \leqslant P_{chp,ymdhs}^{t} + P_{AB,ymdhs} + P_{TSS,ymdhs}^{char/disch} \tag{4b}$$

The energy conversion/generation of opted units comprising PV, WT, bidirectional transformer, and the auxiliary boiler is modeled, respectively, as (5a)–(5d). It is worthwhile to note that the hourly power generated by RERs is determined by the normalized forecasted generation times the associated installed capacity. In this paper, the power curve is utilized to measure the value of the power produced by WT/PV units as a function of wind speed/irradiation and air temperature [77,78].

$$P_{pv,ymdhs}=\sum_{c}P^{DC}_{pv,ymdhs}(\partial^{irradiation}_{s})\cdot\alpha^{ef,inverter}_{pv}\cdot\kappa_{pv,mh}\cdot I_{pv,yc} \tag{5a}$$

$$P_{wt,ymdhs}=\sum_{c}P^{AC}_{wt,ymdhs}(\partial^{wind}_{s})\cdot\alpha^{ef,converter}_{wt}\cdot\kappa_{wt,mh}\cdot I_{wt,yc} \tag{5b}$$

$$P^{in/out}_{trans,ymdhs}=\sum_{c}P^{Netpur/sale,e}_{ymdhs}\cdot\alpha^{ef}_{trans}\cdot I_{trans,yc}\cdot V_{trans,ymdhs} \tag{5c}$$

$$P_{AB,ymdhs}=\sum_{c}\alpha^{ef}_{AB}\cdot\upsilon_{AB,ymdhs}\cdot I_{AB,yc}\cdot V_{AB,ymdhs} \tag{5d}$$

The fuel consumption function of the installed CHP unit is modeled as (6a) based on [79]. In this paper, the electric and heat power generations of the installed CHP units are presumed to be dependent on each other by utilizing the power-heat feasible operating regions of the type-one CHP unit in [80], as formulated in (6b)–(6d).

$$\begin{aligned}\upsilon_{chp,ymdhs}=&\,a\cdot\left(P^{e}_{chp,ymdhs}\right)^{2}+b\cdot P^{e}_{chp,ymdhs}+c\cdot\left(P^{h}_{chp,ymdhs}\right)^{2}+d\cdot P^{h}_{chp,ymdhs}\\&+e\cdot P^{e}_{chp,ymdhs}\cdot P^{h}_{chp,ymdhs}+g\end{aligned} \tag{6a}$$

$$P^{e}_{chp,ymdhs}-P^{eA}_{chp}-\frac{P^{eA}_{chp}-P^{eB}_{chp}}{P^{tA}_{chp}-P^{tB}_{chp}}\cdot\left(P^{t}_{chp,ymdhs}-P^{tA}_{chp}\right)\leqslant 0 \tag{6b}$$

$$P^{e}_{chp,ymdhs}-P^{eB}_{chp}-\frac{P^{eB}_{chp}-P^{eC}_{chp}}{P^{tB}_{chp}-P^{tC}_{chp}}\cdot\left(P^{t}_{chp,ymdhs}-P^{tB}_{chp}\right)\geqslant-\left(1-V_{chp,ymdhs}\right)\cdot Mbig \tag{6c}$$

$$P^{e}_{chp,ymdhs}-P^{eC}_{chp}-\frac{P^{eC}_{chp}-P^{eD}_{chp}}{P^{tC}_{chp}-P^{tD}_{chp}}\cdot\left(P^{t}_{chp,ymdhs}-P^{tC}_{chp}\right)\geqslant-\left(1-V_{chp,ymdhs}\right)\cdot Mbig \tag{6d}$$

The amount of energy generated by installed DGs cannot exceed their installed capacity times the associated availability, as formulated in (7a)–(7f). It is noteworthy to mention that Eqs. (7e) and (7f) represent the power and heat CHP generation limits, respectively.

$$-\sum_{c}P^{Max}_{trans,c}\cdot I_{trans,yc}\cdot A_{trans,c}\leqslant P^{in/out}_{trans,ymdhs}\leqslant\sum_{c}P^{Max}_{trans,c}\cdot I_{trans,yc}\cdot AV_{trans,c} \tag{7a}$$

$$\sum_{c}P^{Min}_{AB,c}\cdot I_{AB,yc}\leqslant P_{AB,ymdhs}\leqslant\sum_{c}P^{Max}_{AB,c}\cdot I_{AB,yc}\cdot AV_{AB,c} \tag{7b}$$

$$0\leqslant P_{pv,ymdhs}\leqslant\sum_{c}P^{Max}_{pv,c}\cdot I_{pv,yc}\cdot AV_{pv,c} \tag{7c}$$

$$0\leqslant P_{wt,ymdhs}\leqslant\sum_{c}P^{Max}_{wt,c}\cdot I_{wt,yc}\cdot AV_{wt,c} \tag{7d}$$

$$\left(\sum_{c}P^{Max}_{chp,c}\cdot I_{chp,yc}\right)\cdot P^{eC}_{chp}\cdot V_{chp,ymdhs}\leqslant P^{e}_{chp,ymdhs}\leqslant\left(\sum_{c}P^{Max}_{chp,c}\cdot I_{chp,yc}\cdot AV_{chp,c}\right)\cdot P^{eA}_{chp}\cdot V_{chp,ymdhs} \tag{7e}$$

$$0\leqslant P^{t}_{chp,ymdhs}\leqslant\left(\sum_{c}P^{Max}_{chp,c}\cdot I_{chp,yc}\cdot AV_{chp,c}\right)\cdot P^{tB}_{chp}\cdot V_{chp,ymdhs} \tag{7f}$$

The exchanged power/natural gas with the utility network is limited by the capacity of the line/pipeline connecting the MCMG to the utility network, as formulated in (8a) and (8b). The natural gas amount dedicated to the installed CHP and auxiliary boiler units is declared as (8b).

$$-P^{Net,e,Max}\leqslant P^{Netpur/sale,e}_{ymdhs}\leqslant P^{Net,e,Max} \tag{8a}$$

$$0\leqslant P^{Net,g}_{ymdhs}=\upsilon_{chp,ymdhs}+\upsilon_{AB,ymdhs}\leqslant P^{Net,g,Max} \tag{8b}$$

The state of charge of the installed storage is evaluated on the basis of the stored energy in previous hours, net charged power, and energy loss, as modeled in (9a) and (9b). The energy and power of the storage systems are constrained by their installed capacity times the associated availability, as (9c) and (9d). It is to be noted that if the storage system is charging, P^{R}_{uc} is negative, and the state of charge will increase, and vice versa. Besides, the storage net charge is assumed to be zero at the end of each day to acquire sustainable storage utilization in the planning horizon (9e).

$$SOC_{uymdhs}=SOC_{uymd(h-1)s}-P^{char/disch}_{uymdhs}-P^{loss}_{uymdhs}\forall u\in SS \tag{9a}$$

$$P^{loss}_{uymdhs}=SOC_{uymdhs}\cdot\alpha^{loss}_{u}\forall u\in SS \tag{9b}$$

$$\sum_{c}SOC^{Max}_{uc}\cdot I_{uyc}\cdot(1-DOD_{uc})\leqslant SOC_{uymdhs}\leqslant\sum_{c}SOC^{Max}_{uc}\cdot I_{uyc}\cdot AV_{uc}\forall u\in SS \tag{9c}$$

$$\sum_{c}-P^{R}_{uc}\cdot I_{uyc}\cdot AV_{uc}\cdot\alpha^{char}_{u}\leqslant P^{char/disch}_{uymdhs}\leqslant\sum_{c}P^{R}_{uc}\cdot I_{uyc}\cdot AV_{uc}/\alpha^{disch}_{u}\forall u\in SS \tag{9d}$$

$$\sum_{h}P^{char/disch}_{uymdhs}=0\forall u\in SS \tag{9e}$$

The DRP scheme of paper [81] is employed in this work, which is formulated in (10a)–(10d). Demand variations must be balanced daily (10a). Eqs. (10b) and (10c) model the enrolled customers that are participating in DRPs for shifting a share of demands up or down; in other words, it quantifies the maximum hourly amount of shiftable demands of different users. Eq. (10d) is required to prevent the shifting up or down simultaneously. The conservative method of informing the energy market prices to customers is prone to cause new peaks since MCMG's customers might follow a different schedule and use the capability of demand shifting to other hours compared to the utility's forecast once actual prices are received. Thus, this work employs a novel concept named LEP evaluator to avoid the likelihood of any other peak occurrence to the grid. The hourly LEP of energy demand shifting for electrical and thermal demands can be evaluated by dividing the quantity of energy import from the utility network times its energy market price, with the sum of DER generations plus the exchanged power minus the amount of total curtailed energy demands. To clarify, the energy tariff for enrolled active participants will be lower than the hourly energy market price if they consume less in peaks, and vice versa. The LEP signals for shifting the electrical and thermal demands of elastic users are formulated in (10e) and (10f), respectively. In short, the proposed model of LEP is much more efficient in enabling and motivating enrolled responsive customers to shift their demand from peaks to off-peaks.

$$\sum_h D^{shup,l}_{ymdhsn} = \sum_h D^{shdo,l}_{ymdhsn} \forall l \in \{e,t\} \tag{10a}$$

$$0 \leqslant D^{shup,l}_{ymdhsn} \leqslant D^l_{ymdhsn} \cdot LPF^l_n \cdot IS^{shup,l}_{ymdhsn} \forall l \in \{e,t\} \tag{10b}$$

$$0 \leqslant D^{shdo,l}_{ymdhsn} \leqslant D^l_{ymdhsn} \cdot LPF^l_n \cdot IS^{shdo,l}_{ymdhsn} \forall l \in \{e,t\} \tag{10c}$$

$$0 \leqslant IS^{shup,l}_{ymdhsn} + IS^{shdo,l}_{ymdhsn} \leqslant 1 \forall l \in \{e,t\} \tag{10d}$$

$$\pi^{shifting,e}_{ymdhs} = \frac{P^{Netpur,e}_{ymdhs} \cdot \pi^{Netpur,e}_{ymdhs} + (P^e_{chp,ymdhs}/P^e_{chp,ymdhs} + P^t_{chp,ymdhs}) \cdot \pi^{Net,g}_{ymdh}}{P^{in}_{trans,ymdhs} + P^e_{chp,ymdhs} + P_{pv,ymdhs} + P_{wt,ymdhs} - P^{char/disch}_{ESS,ymdhs} + \sum_n P^{ens,t}_{ymdhsn}} \tag{10e}$$

$$\pi^{shifting,t}_{ymdhs} = \frac{P_{AB,ymdhs} \cdot \pi^{Net,g}_{ymdhs} + (P^t_{chp,ymdhs}/P^e_{chp,ymdhs} + P^t_{chp,ymdhs}) \cdot \pi^{Net,g}_{ymdh}}{P^t_{chp,ymdhs} + P_{AB,ymdhs} - P^{char/disch}_{TSS,ymdhs} + \sum_n P^{ens,t}_{ymdhsn}} \tag{10f}$$

The load shedding is utilized to regulate the frequency of the MCMG in case of any imbalance occurrence, which is restricted by curtailable loads (11a). This paper employs the equivalent loss factor (ELF) as an index to assess the proposed MCMG's reliability level [43], which is defined as the ratio of daily total curtailed electricity demands to the total demands (11b). ELF index should be restricted by the maximum amount (11c), which is commonly considered below 1% for remote communities and below 0.01% for developed countries.

$$0 \leqslant P^{ens,l}_{ymdhsn} \leqslant D^l_{ymdhn} + D^{shup,l}_{ymdhsn} - D^{shdo,l}_{ymdhsn} - CL^l_{ymdhn} \forall l \in \{e,t\} \tag{11a}$$

$$ELF_{ymds} = \frac{1}{N_h} \sum_h \sum_n P^{ens,e}_{ymdhsn} / D^e_{ymdhsn} \tag{11b}$$

$$ELF_{ymds} \leqslant ELF^{Max} \tag{11c}$$

Reserve margin is deemed available to compensate for any unexpected shortfall in generation or increase in demand that may be due to the probabilistic nature of resources [82]. The required DER available online reserve must be at least equal to a target value, which depends on the critical demand of the proposed MCMG (12a). Dispatchable DGs participating in providing reserve must be online to quickly generate energy when the MCMG face any shortages during any disruptions (12b). Charging power of batteries can also be employed to participate in the reserve availability since they can be quickly interrupted and, thereafter, start discharging to supply critical loads (12b). In the worst-case scenario, loads with low priorities will be curtailed to maintain the MCMG frequency within the allowable limits.

$$R^{target}_{ymdhs} = \sum_n D^e_{ymdhsn} \cdot RM \tag{12a}$$

$$\begin{aligned} R^{target}_{ymdhs} \leqslant &+ \left(\sum_c \left(P^{Max}_{chp,c} \cdot I_{chp,yc} \right) \cdot V_{chp,ymdhs} - P^e_{chp,ymdhs} \right) + \left(\alpha^{char/disch}_{ESS} \cdot min \left(SOC_{ESS,ymdhs}/N_h, \sum_c P^R_{ESS,c} \cdot I_{ESS,yc} \right) \right) \\ &+ \left(\sum_n \left(D^e_{ymdhsn} + D^{shup,e}_{ymdhsn} - D^{shdo,e}_{ymdhsn} - P^{ens,e}_{ymdhsn} \right) \right) + \left(\sum_c \left(P^{Max}_{trans,c} \cdot I_{trans,yc} \right) \cdot V_{trans,ymdhs} - P^{in}_{trans,ymdhs} \right) \end{aligned} \tag{12b}$$

To achieve the targeted goals of GHG emissions reduction by 2050 [83], Eq. (13a) is imposed as a constraint to offset the amount of received energy from the utility network (operational emissions) and on-site renewable penetrations (avoided emissions) by independent system operator [59]. It is worth noting that the conventional gas-fired units burn the energy received from the utility network, and thereupon emits air pollutions. Finally, the authors suggest that in order to encourage renewable resource penetrations to accomplish the aforementioned goal, the electricity sale price (feed-in tariff) for MCMG customers in the spot markets should be modified by introducing an incentive coefficient, which elevates the hourly local electricity sale price for MCMGs with higher renewable resource penetrations (13b).

$$0 \leqslant NZE_{ymds} = \sum_h^{N_h} \sum_p \left(\sum_{u \in \{pv,wt\}} P_{uymdhs} \cdot EF_{up} - \sum_{u \in \{trans,chp,AB\}} P_{uymdhs} \cdot EF_{up} \right) \tag{13a}$$

$$\pi^{Netsale,e,new}_{ymdhs} = \pi^{Netsale,e,old}_{ymdhs} + \sum_c (P^{Max}_{pv,c} \cdot I_{pv,yc} + P^{Max}_{wt,c} \cdot I_{wt,yc}) \cdot \zeta \tag{13b}$$

In addition to the terms above, renewable energy and conventional power penetration metrics (REP and MCPP) are calculated in this paper, as modeled in [77].

4. Numerical simulations

A conceptual customer MCMG as a test-case system is utilized to be installed for a group of customers with a maximum initial aggregated electrical and thermal load demands of 730 kW and 290 kW, respectively [77]. The aggregated load demand is a combination of residential, commercial, and industrial customers allocating 10%, 20%, and 70% of the total demand. The VOLL is taken to be \$1.84/kWh, \$6.19/kWh, and \$8.3/kWh for residential, commercial, and industrial customers, respectively. The set of DERs includes a bidirectional transformer, CHP, auxiliary boiler, PV, WT, and electrical and thermal energy storage systems, with five available commercial candidates, as represented in Table 1 and Table 2. It is noteworthy to mention that the model structure can contain either one candidate for each set or none. The planning horizon is considered to be five years. Electrical and thermal loads, wind speed, and solar irradiance forecast errors are obtained via their corresponding probability distribution functions as utilized in [77,84]. The electricity and natural gas price data are derived from the online ISO-New England and Henry Hub Natural Gas data repositories [85,86]. Each planning year is partitioned into 12 monthly periods, while two typical days (weekdays and weekends) of two typical six months (first half of the year and second half of the year) for each year are asserted to eliminate the complexity of numerical computations. Ten hours of islanding are considered annually in this study as well. In this study, ELF is constrained to be lower than 0.01, and the required reserve is assumed to be 10% of the critical load at each hour. Additionally, the annual load and price growth rates are assumed to be 2.9% and 2.5%, respectively. The nominal discount rate is considered to be 5% for project finance. Table 3 lists the numerical values for the pollution factors and related taxes, which are borrowed from [81]. Herein, the avoided emission factors for RERs are assumed the same as the grid emission production factor. The problem was formulated and solved by the joint genetic algorithm of MATLAB and the MINLP model of GAMS.

The following cases are studied:

Case 1. Non-microgrid operation of the community
Case 2. MCMG design

Table 1
Dispatchable and nondispatchable units' characteristics of the available candidates.

Units	Candidate	Rated power (kW)	Efficiencies (%) el.	th.	∑	Investment & installation cost (M$)	Maintenance coefficient ($/kWh)	Availability (%)
Bidirectional transformer	1	250	92	–	92	0.02	0.0030	96.5
	2	500	94	–	94	0.045	0.0027	97.4
	3	750	89	–	89	0.06	0.0024	98.6
	4	1000	87	–	87	0.08	0.0022	99.5
	5	1300	88	–	88	0.10	0.0020	99.8
Combined heat and power (CHP)	1	500	Pertains to FORs			0.18	0.0190	98.0
	2	1000				0.35	0.0180	95.0
	3	1500				0.51	0.0170	97.5
	4	2000				0.67	0.0160	99.0
	5	2500				0.85	0.0150	98.4
Auxiliary Boiler (AB)	1	100	–	90	90	0.02	0.0090	96.5
	2	200	–	87	87	0.039	0.0080	96.9
	3	300	–	85	85	0.058	0.0050	99.0
	4	400	–	83	83	0.077	0.0030	99.5
	5	500	–	80	80	0.1	0.0020	95.8
Photovoltaic (inverter's efficiency)	1	100	98.2	–	98.2	0.110	0.0010	97.2
	2	200	97.7	–	97.7	0.145	0.0015	97.1
	3	300	96.2	–	96.2	0.190	0.0017	98.6
	4	400	97.5	–	97.5	0.250	0.0019	97.2
	5	500	97.2	–	97.2	0.450	0.0020	96.4
Wind turbine (converter's efficiency)	1	100	98.5	–	98.5	0.24	0.0020	96.8
	2	200	98.3	–	98.3	0.4	0.0030	96.5
	3	300	97.8	–	97.8	0.6	0.0034	95.6
	4	400	97.5	–	97.5	0.75	0.0038	95.1
	5	500	97.2	–	97.2	0.9	0.0040	95.0

M$: million dollars, FOR: feasible operating region.

Table 2
Energy storage characteristics of the available candidates.

Units	Candidate	Rated energy (kWh)	Rated power (kW)	Charge & discharge efficiency rate (%)	Investment & installation cost (M$)	Availability (%)
Electrical Storage (ESS)	1	50	20	85	0.012	97
	2	100	30	82	0.020	97
	3	150	50	83	0.030	97
	4	200	60	80	0.040	97
	5	300	80	85	0.065	97
Thermal Storage (TSS)	1	50	20	85	0.010	98
	2	100	30	90	0.015	98
	3	150	50	80	0.025	98
	4	200	60	75	0.035	98
	5	300	80	70	0.045	98

M$: million dollars.

Table 3
Emission factors and taxes related to pollutants.

	Unit	CO_2	SO_2	NO_2
Utility grid	(kg/kWh)	0.00143	0.000007	0.00039
CHP	(kg/kWh)	0.00160	0.000008	0.00044
Auxiliary Boiler	(kg/kWh)	0.00176	0.000009	0.00048
Emission tax	($/kg)	0.014	0.99	4.2

Case 3. MCMG design with DRPs
Case 4. MCMG design with DRPs under NZE constraint
Case 5. Financial feasibility sensitivity analysis on the ratio of incentive coefficient for MCMG design

In case 1, the community is supplied via the existing system before MCMG deployment; simply put, electrical and thermal demands are fulfilled by utility network and natural gas furnaces. From case 2 to 5, the optimal mixture of DER is determined to be deployed in the MCMG. In detail, DRP, along with NZE constraint, is not applied in case 2, while the impact of DRP on the MCMG planning is assessed in case 3. In case 4, the MCMG is planned under the NZE policy to decrease environmental degeneration by regulatory changes. Lastly, the sensitivity analysis of the value of incentive coefficient impact on RER penetration is explored in case 5 to prompt private sectors to fulfill a share of their demands by RERs, and consequently pave the way for accomplishing an NZE network. The detailed results are presented in Tables 4–7 and Figs. 2 and 3, which summarize the results of the optimal configurations, financial performances, operational performances of DERs, reliability analysis, electricity demand shifting price analysis, as well as discounted cash flow diagrams of the cases. It is worth noting that the MCMG needs to replace the existing conventional transformer with a bidirectional one to be able to sell the surplus electricity to the utility network.

4.1. Optimal configuration and operation performance analysis

Tables 4 and 5 summarize the optimal configuration and operation performances of all case studies. Herein, three operation zones, i.e., low, medium, and high are utilized for elaborating the overall performance of

Table 4
Results of optimal configurations.

MCMG units	Case 1		Case 2		Case 3		Case 4		Case 5	
	type	Comm. year	type	Comm. year	type	Comm. year	type	Comm. year	type	Comm. year
Transformer	existing power system (conventional transformer)		5	1	5	1	5	1	5	1
CHP	–		4	1	4	1	4	1	4	1
AB	–		0		0		0		0	
PV	–		0		0		5	1	5	1
WT	–		0		0		2	1	2	1
ESS	–		1	1	1	1	1	1	1	1
TSS	–		0		0		0		0	

Comm. year: commissioning year.

Table 5
Results of summary performances.

DERs		Case 1	Case 2	Case 3	Case 4	Case 5
Transformer	Purchase	H	L	L	L	L
	Sale	–	H	H	H	H
CHP		–	M	M	M	M
AB		–	–	–	–	–
PV		–	–	–	H	H
WT		–	–	–	H	H
ESS		–	M	M	M	M
TSS		–	–	–	–	–

L: low, M: medium, H: high.

each scheduled unit over the planning horizon in one comprehensible table, as listed in Table 5. Case 1 is simulated as a base case to address the energy savings for comparative purposes with other cases as if the community is supplied by the utility networks through the existing energy infrastructures; thus, multiple demands of the community are supplied by an existing conventional transformer and natural gas furnaces. From Table 4, a bidirectional transformer with a maximum size is installed and utilized moderately to benefit from the considerable sales of surplus electricity generation by the pinpointed CHP to the utility network over the planning horizon in cases 2 and 3. Both cases install the same CHP close to maximum size in the first year as the main and weightiest supplier of electrical and thermal demands in the community. A small-sized ESS with medium utilization is also conducted in these cases for enabling the MCMG operator to take advantage of price differentials and anomalous energy needs during severe incidents like upstream disruptions over and above the aforementioned mounted units. In case 3, although DRP implementation results in lower energy cost, a similar configuration is derived in comparison to case 2. Thus, DRP implementation would not affect DER mixtures. It should be noted that RERs are not installed in the aforementioned cases on the grounds that the renewable units cannot ensure a fixed power output, resulting in significant cost-inefficiency in comparison with the dispatchable DGs. However, the optimal solutions in cases 4 and 5 that consider policies and regulations to support investments on renewable units, such as NZE regulation and feed-in tariff, are different from the former cases. Both cases 4 and 5 allocate the same physical technologies of case 3 plus PV unit type 5 and WT unit type 2 so as to procure an NZE system. The coincidence of the solar unit generation pattern with the variations in load and market price is the dominant reason for the larger solar installation in lieu of the WT unit. It can be observed from Table 5 that the operation performances in cases 4 and 5 are quite similar to case 3, plus maximum utilization of RERs are performed to supply a share of local demands and to sell the surplus power to the utility company. One of the outstanding units installed in all of the MCMG-based cases is the ESS that smooth oscillations of demands and renewable resources, as well as flattening the electrical demand curves. It is worthwhile to mention that minute annual load growth is the main reason for commissioning scheduled units in the first year rather than the subsequent years. All things considered, the consequence certifies the notability of the contemporaneous supply of electricity and heat demands by a reliable CHP in all MCMG-based cases, together with a bidirectional transformer which is an interface between the MCMG and utility network to import or export power, and consequently provides economic benefits for the MCMG.

4.2. Financial feasibility analysis

The financial feasibility table results of all case studies, along with a breakdown of their associated costs and benefits, are listed in Table 6. Before scrutinizing the results, it is noteworthy to mention that all monetary values of Table 6 are in present-worth values and in per units. Besides, the base unit quantity for the present-worth cost of case 1 is equal to $3.82 million.

Case 1. It can be observed from Table 6 that the operation and emission costs embrace a vast majority of the overall cost in case 1,

Table 7
Results of reliability analysis in the last year.

Reliability indices (pu)	Case 1	Case 2	Case 3	Case 4	Case 5
MCPP	–	7.218	7.218	7.218	7.218
REP	–	0.000	0.000	0.300	0.300

REP: renewable energy penetration, MCPP: MG conventional power penetration, pu: per unit.

Table 6
Results of financial performances.

MCMG financial data	Unit	Case 1	Case 2	Case 3	Case 4	Case 5 (scenario 1)	Case 5 (scenario 2)
Investment cost	pu	0.0000	0.2367	0.2367	0.4910	0.4910	0.4910
Operation cost + demand shifting payment	pu	0.4847	−0.8859	−0.8895	−0.9235	−1.0170	−1.1104
Maintenance and storage degradation cost	pu	0.0139	0.2880	0.2888	0.2628	0.2628	0.2628
Peak demand cost	pu	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186
Emission cost	pu	0.4224	0.0338	0.0339	0.0308	0.0308	0.0308
Unserved energy cost	pu	0.0603	0.0000	0.0000	0.0000	0.0000	0.0000
Total cost	pu	1.0000	−0.3088	−0.3115	−0.1203	−0.2137	−0.3072
Savings	%		131	131	112	121	131
DPP	year		3.098	3.092	4.961	4.405	3.977

M$: million dollars, DPP: discounted payback period, pu: per unit. *Herein, positive and negative values signify cash outflows and inflows, respectively.

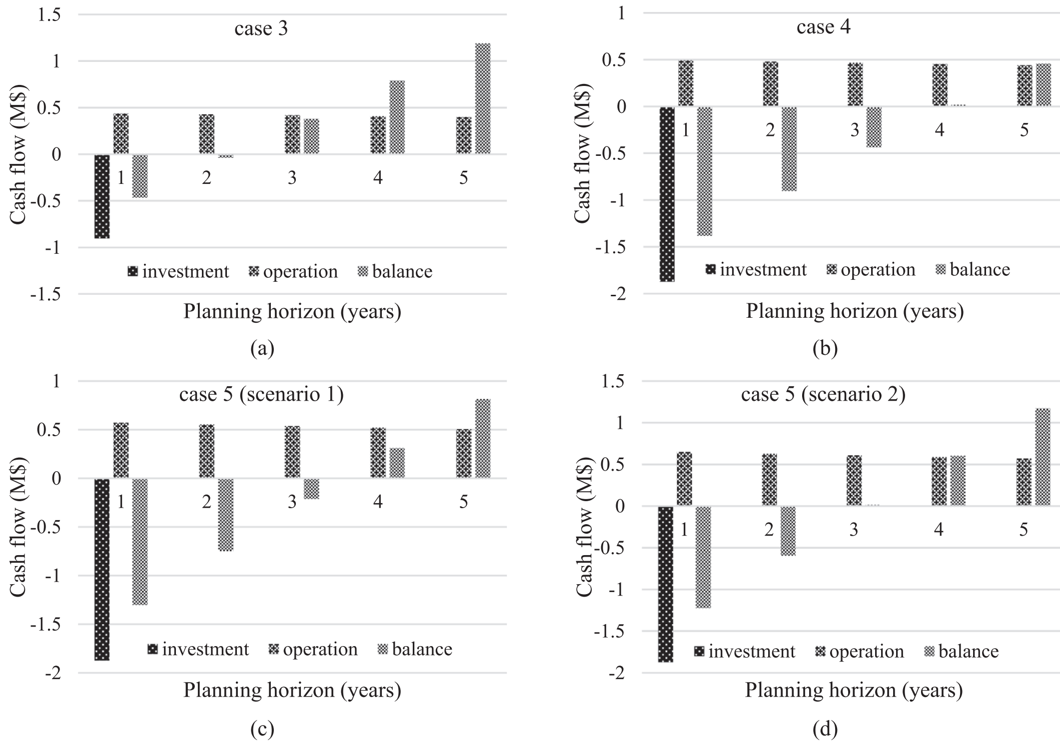


Fig. 2. MCMG discounted cash flow diagram of case 3–5 over the planning horizon (a) case 3 (b) case 4 (c) case 5 with incentive coefficient = 1e−005 (d) case 5 with incentive coefficient = 2e−005.

which constitutes 48% and 42% of the total cost, respectively. Regardless of the operation and emission costs, unserved energy cost encompasses about 6% of the overall cost owing to utility service disruptions while the maintenance and peak demand charge costs are trivial.

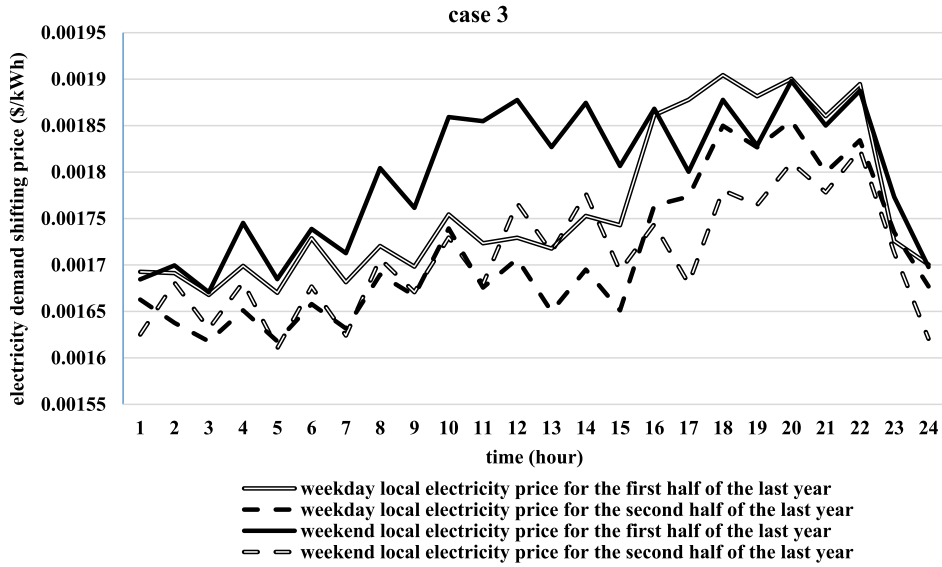
Case 2. The total cost is intensely depleted in overall in case 2 as compared to case 1 without MCMG installation. In this case, the investment and maintenance costs in the customer MCMG architecture represent a colossal quantity of the overall cost. On the other hand, the emission cost is remarkably declined in this case due to CHP utilization, compared to case 1, while unserved energy cost is fallen to zero by providing the community energy demands uninterruptedly with local resources. On top of all that, the operational cash inflows manifest that the MCMG stakeholders make substantial financial gains by selling as much energy as possible to the utility grid once the price signals justify it economically; in other words, the operation cost becomes negative as if the stakeholders gain revenue from the energy exchange with the utility company. By and large, the MCMG economic viability of case 2 is justified since the accrued revenue outweighs the investment cost; that is to say, total cost becomes negative. Additionally, the results of case 2 advocate a savings of 131% with a reasonable discounted payback period (DPP) of 3.098 years. It is worth pointing out that the savings expressed as percentages are measured by comparing the overall cost discovered through simulation in the base case (non-microgrid case) with that of the MCMG planning cases, whereas DPP reveals the number of years until the investment in a project is recovered.

Case 3. In case 3, financial breakdowns of the associated costs are almost similar to that in case 2, except that the community revenues become slightly larger due to the peak-shaving dispatch with the inclusion of DRP. Indeed, the comparison between cases 2 and 3 affirms the superiority of active costumers' participation in peak-shifting. Also, the results of cases 2 and 3 have led us to conclude that none of the renewable units will be installed since the investment costs of these units outweigh the economic benefits arising from the amount of produced energy and significant fluctuations of such resources.

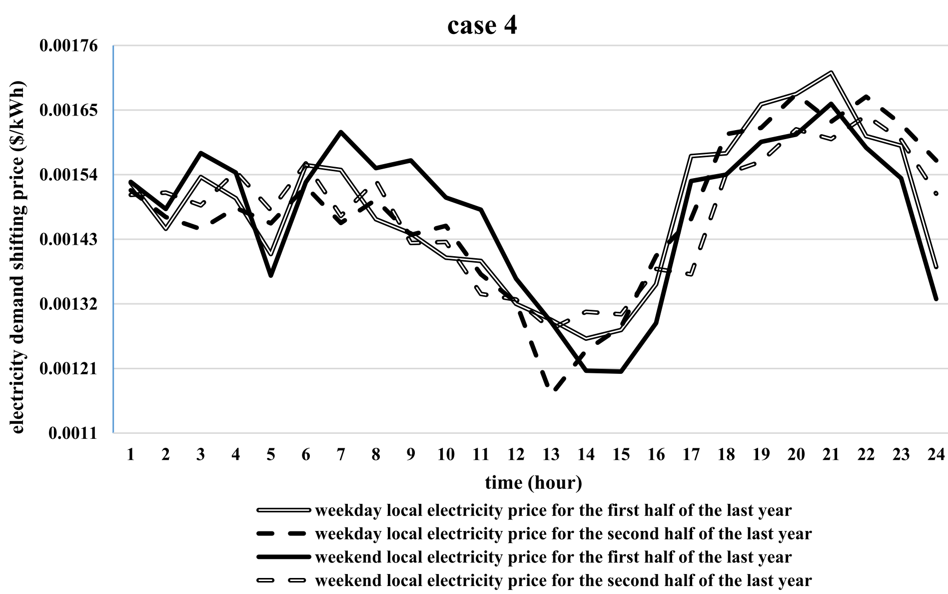
Case 4. Compared to case 3, the NZE policy of case 4 has a decisive impact on the optimal DER mix and financial feasibility of the customer MCMG. Although an NZE system is achieved in case 4, the MCMG project's financial feasibility is dramatically decreased with a lower savings of 112% compared to case 3. From case 3 to 4, adding the NZE constraint has led to a 9.2% emission cost reduction. Nevertheless, it causes 107% higher investment cost. On the contrary, more profitable electricity sale to the utility company is attained due to RER utilization in this case while the maintenance cost is mildly declined compared to case 3. To summarize, despite the configuration adopting the NZE balance still retains financially feasible with accumulated revenues over the planning horizon, it is sharply depleted by 39% with a significantly extended DPP of 4.961 years in comparison with case 3, which would make RER assets' investment less attractive.

Case 5. In terms of financial performances, the customer MCMG deployment of case 3 appears to be the best optimal planning option among the cases above; so that the same financial performance circumstances of case 3 need to be realized in case 4 under NZE policy for persuading investors to deploy RERs. Thus, incentives together with policies should be considered to support clean generations; we thereupon in case 5 examine the impact of variation in incentive coefficients on the financial feasibility of the proposed customer MCMG with RER penetration (with two different incentive coefficient scenarios equal to 1e-005 and 2e-005). It is evident that, though the project financial feasibility of both scenarios of case 5 compared to case 4 are remarkably stepped-up by 178% and 255%, only the second scenario of case 5 planning yields the same savings as well as accumulated revenues close to that in case 3, which is indeed the optimal way forward even with roughly one-year DPP extension of this scenario compared to case 3.

As an illustration, a summary of the cash flow of cases 3 to 5 are



(a)



(b)

Fig. 3. Local electricity demand shifting price (a) case 3 (b) case 4.

presented to shed some light on the annual monetary values (see Fig. 2). Given these points, the presented results validate the prominence of renewable energy incentives to deploy clean energy resources as if the higher the incentive rates, the more profitable MCMG projects with green resources become. However, the MCMG deployment with high penetration of RERs will be more financially attractive in the distant future in case the investment cost of RER drops intensely, but, for all that, the feed-in tariff can be recognized as a quick and efficient solution for reducing GHG emissions by at least 40% in the European Union by 2030 [72].

4.3. Reliability and demand response program analysis

A succinct report of the reliability assessment is presented in Table 7, indicating that the identical MCPP for all MCMG-based case studies is acquired since the same conventional resources are utilized. Herein, considerable values of MCPP advocate that oversized conventional resources are appointed within the customer MCMG in proportion to the demand in order to sell the excess and lucrative power generated by the gas-fired unit to the utility company. It can also be observed from Table 7 that the REP of 30% is acquired in cases 4 and 5 under NZE policy. The results manifest that RER penetration of only 30% along with on-site dispatchable DGs is required to procure the targeted GHG emissions even though renewable generation represents a small portion of the generation mix in the customer MCMG. Besides, enrollment in DRP is regarded in this paper as a means not only to reduce energy costs but also to provide economic benefits by shifting energy demands in peaks. This study advocates that the customer MCMG with enabled users under LEP policy would procure notable electrical peak mitigations of about 7–18% and 10–23% ranges in cases 3 and 4, respectively. Furthermore, the local electricity demand shifting price of cases 3 and 4 is illustrated in Fig. 3. According to Fig. 3 (case 3), LEP at the weekends would generally get a higher value than weekdays to diminish the electricity demand shifting since the electrical demand curve is almost flat at weekends and so, consequently, the energy shifting would not be prone to cause new peaks. To put it another way, the lower the LEP becomes, the higher responsive users participate in peak-shavings. The most outstanding result is observed from the comparison of LEP trends of cases 3 and 4 in Fig. 3, which heightens the prominence of RER generations on LEP reductions. For one thing, the LEP pattern of case 4 compared to case 3 is shrunk up to 33% in the light of renewable generations. Altogether, the LEP evaluator module for elastic loads provides a hedging mechanism for the customer MCMG to mitigate peaks.

5. Discussions

The benefits from MCMGs are not only economical but also environmental as a means of creating NZE communities, albeit incentives along with regulations need to be adapted to meet environmental goals established by states or regulatory agencies. However, the economic benefits of customer MCMG deployments with RER penetrations should be assessed to justify the considerable investment on DERs in terms of various economic measures such as present-worth value, savings, and DPP. According to the studied cases, the following could be deduced.

- Economic viability and benefits: The proposed model would determine whether the MCMG portfolio ensures the projected return on investment costs, and would explore the financial feasibility of the MCMG projects with RER penetrations. The presented results indicate that joint economic and eco-friendly milestones are only attainable in the presence of renewable energy incentives by ensuring a quicker return on investment in terms of both profits and savings. Additionally, the reliability cost for MCMG-based systems is wiped out wholly. To sum up, this paper is informative and compelling for renewable energy policymakers to perceive the influence of incentives on the short-term promotion of green energies within customer MCMG systems.
- Noneconomic benefits: MGs' benefits are not just economic ones. MGs not only can sustain the power supply of at least high-prioritized local loads in the event of grid outages but also can serve as a quick and alternative solution to the intense investment of brown energies in the centralized grid emitting more air pollution than small-scale DERs. Thus, this paper propounds a vigorous weighting system that offsets the emission balance quantity of the proposed MCMG system to attain the binding emission-neutral target in the European Union by 2030. To conclude, numerical simulations exhibited environmentally friendly merits of the proposed MCMG planning model.
- Optimal DER selection: The proposed model determines the optimum combination of DERs and their associated commissioning year to minimize the total planning cost based on the economic, reliability, and emission-neutral considerations. The results manifest the notability of CHP installation as the primary resource for the supply of both electrical and thermal requirements, together with bidirectional transformer as an interface to import or, particularly, export excess power to increase revenue streams for the customer MCMG. Besides, the significance of electrical storage installation is highlighted within the customer MCMG as buffers to dispel the oscillations of demands and renewable resources. In parenthesis, a binding renewable energy share of at least 32% of the energy consumption is targeted in the European Union by 2030 [72]. Indeed, the REP of about 30% in proportion to the total demand is ensued in this study under NZE policy to procure the targeted renewable energy penetration, stated by the European Commission. Furthermore, larger solar units than WT would be mounted among nondispatchable units in this study on the grounds of the partial coincidence of its generation pattern with load and market price variations.
- Demand response: Active participation of customers in demand shifting during peak periods would cause savings in electricity bills. Thus, this study presents a novel DRP model based on the LEP concept to maximize the benefits of the electric power participants by shifting demands from peaks to off-peaks while assuring the shifting would not originate new peaks. Indeed, peak mitigation of about 7–23% ranges brings to light the effectiveness of the proposed DRP model.
- Methodology: A decomposition method is utilized to decouple the long-term investment and short-term operation problems by blending the genetic algorithm of MATLAB and the MINLP model of GAMS software. The investment plan attained in the master problem is examined in the subproblem to find optimal DER schedule while checking the desired levels of reliability, online reserve, and NZE constraints.

6. Conclusion

This paper presented a decision-making framework to justify the customer multi-carrier microgrid deployments from the economic, reliability, and environmental outlooks. An optimal emission-neutral configuration mix of distributed energy resources was determined within the proposed customer multi-carrier microgrid while minimizing the overall deployment cost subject to the prevailing planning and operational constraints. The proposed model also explored the effect of renewable energy incentives along with net-zero emission regulation on the short-term realization of low-cost and emission-neutral energy zones. Additionally, load prioritization with a distinctive value of lost loads along with a novel demand shifting of demand response schemes was employed to avert or diminish any staggering load curtailment penalties led by any unforeseen power system outages. To solve the problem, a decomposition method was adopted to decouple the long-term investment and short-term operation problems for the proposed planning problem. The problems were tied and coordinated through the combination of the genetic algorithm of MATLAB and the mixed-integer nonlinear programming model of GAMS software. Numerical simulations justified the economic viability of net-zero emission-based multi-carrier microgrids in achieving the sustainable energy and climate goals, while further aiding and informing policymakers in drafting renewable energy incentive policy programs to procure the adopted 2030 climate and energy framework by the European Council.

CRediT authorship contribution statement

Mahdi Azimian: Conceptualization, Methodology, Software, Validation, Resources, Data curation, Writing - original draft, Writing - review & editing. **Vahid Amir:** Conceptualization, Methodology, Writing - review & editing, Supervision. **Saeid Javadi:** Writing - review & editing, Supervision.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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