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Substation expansion deferral by multi-objective battery storage scheduling ensuring minimum cost

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ABSTRACT

Ever-increasing consumption of the electricity in the distribution networks encounters network planners with new challenges in terms of expansion requirements. Expanding substations is a technical concern considering various binding conditions. Emerging Battery Energy Storage Systems (BESSs) have the potential to defer substation expansion needs effectively. Although various applications of the BESSs are considered in the literature previously, application of the BESSs to defer substation expansion plans is not addressed adequately. In this context, this paper proposes a novel Multi-Objective Mixed Integer Linear Programming (MOMILP) for BESS operation in distribution networks to simultaneously substation expansion deferral and cost reduction. The proposed model is highly flexible with respect to the planner preferences, without convergence problems, and easily solvable using commercial solvers. The model determines charging and discharging scheduling of the active and reactive power of the BESSs optimally to achieve maximum substation expansion deferral without increasing operation costs. Higher degrees of the expansion deferral can be achieved at the expanse of the negligible cost increase. Furthermore, details of the whole BESS system including various parts and active/reactive power relations and limits are modeled accurately to better demonstrate real-life situations. Results of the simulations demonstrate accuracy and also functionality of the proposed method.

1. Introduction

Electric energy consumption is continuously increasing because of the population growth, society modernization, and environmental implications leading to adopting new electric technologies, e.g. electric vehicles [1]. Meeting consumption growth requires new investments in the supply chain components including power generation, transmission, sub-transmission, distribution, and linking substations [2]. The sub-transmission substations are located between sub-transmission and medium voltage distribution networks. These substations play a vital role in the supply chain considering that they supply final users of the electricity. Physical expansion of the sub-transmission substation is generally a challenging task considering several binding situations related to the various technical and financial requirements [3]. This matter enforces network planners to use various expansion deferral plans to get rid of physical expansion of the various part of the system [4]. Various expansion deferral methods have been proposed in the literature to date. The previously proposed methods can be broadly classified to implementing Demand Response Programs (DRPs) [5–8], benefiting from the local generation or Distributed Generation (DG) resources [9–18], and also utilizing Battery Energy Storage Systems (BESSs) [19–23]. All of the above-mentioned methods postpone network reinforcement needs by shaving the peak of the load profile.

Peak of the load profile can be removed or shifted to the other time periods by means of Demand Response Programs (DRPs). The DRPs are a type of energy management strategies and aim to change energy consumption paradigm in terms of time and amount of energy used [5]. The changes are in line with the network requirements in case of occurring high price spikes, high energy consumption, or network failures. These programs are also known as demand participation. Totally, demand response helps to decrease energy cost, stabilize price variations, and enhance network reliability [6]. One of the most important applications of the demand participation is peak load shaving. Shaving peak of the load profile can postpone network reinforcement needs to a later time in the future. The participation of the consumers in the energy management process is based on a set of programs called by the network operator and subsequently consumer enrollment in the programs. The consumers participate in the programs voluntarily and constitute a win-win game with the network operator. The benefits for the consumers include lower energy bills or earning monetary

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Nomenclature

Sets

Ψ_T	Time periods
Ψ_I	Network buses
Ψ_G	Network Generators
Ψ_M	Auxiliary linearizing segments

Parameters

$B_{i,j}^{L}$	Line susceptance between buses i and j (Siemens)
$G_{i,j}^{L}$	Line conductance between buses i and j (Siemens)
$EB_{(i)}^{Rate}$	Rated energy capacity of the BESS installed at bus i (kWh)
E_{ini}^{BESS}	Initial stored energy in the BESS installed at bus i (kWh)
$P_{(i,\,t)}^{D}$	Active power demand at bus i and time period t (kW)
$PB_{(i)}^{Rate}$	Power rating of the BESS installed at bus i (kW)
$Q_{(i,\,t)}^{D}$	Reactive power demand at bus i and time period t (kvar)
SS^{Rating}	Substation rated power (kVA)
η^{Ch}	Charging efficiency of the BESS installed at bus i
η^{Di}	Discharging efficiency of the BESS installed at bus i

Variables

$E_{(i,t)}^{BESS}$	Energy stored in BESS installed at bus i and at time period t (kWh)
$BI_{(i)}$	Binary variable indicating installation of BESS at bus i
$BP_{(i,t)}^{Ch}$	Binary variable indicating active power charging status of BESS installed at bus i and at time period t
$BP_{(i,t)}^{Di}$	Binary variable indicating active power discharging status of BESS installed at bus i and at time period t
$BQ_{(i,t)}^{Ch}$	Binary variable indicating reactive power charging status of BESS installed at bus i and at time period t
$BQ_{(i,t)}^{Di}$	Binary variable indicating reactive power discharging status of BESS installed at bus i and at time period t
$PB_{(i,t)}^{Net}$	Net active power exchange of the BESS installed at bus i and at time period t (kW)
$PB_{(i,t)}^{Ch}$	Active charging power of BESS installed at bus i and at time period t (kW)
$PB_{(i,t)}^{Di}$	Active discharging power of BESS installed at bus i and at time period t (kW)
$P_{(i,j\,,\,t)}^{L}$	Active power flow between buses i and j at time period t (kW)
$PS_{(t)}^{G}$	Active power drawn from the substation at time period t (kW)
$QB_{(i,t)}^{Net}$	Net reactive power exchange of the BESS installed at bus i and at time period t (kVar)
$QB_{(i,t)}^{Ch}$	Reactive charging power of BESS installed at bus i and at time period t (kvar)
$QB_{(i,t)}^{Di}$	Reactive discharging power of BESS installed at bus i and at time period t (kvar)
$Q_{(i,j\,,\,t)}^{L}$	Reactive power flow between i and j at time period t (kVar)
$QG_{n,\,k}$	Reactive power generation of bus n at time period k (kvar)
$QS_{(t)}^{G}$	Reactive power drawn from the substation at time period t (kVar)
$SS_{(t)}^{Flow}$ SF_k^{ss}	Apparent power flow of the substation at time period t (kVA)
C_{Tot}	Total network operation cost ($)
$V_{(i,\,t)}^{sqr}$	Square of voltage magnitude of bus i at time period t (PU)
λ	Auxiliary variable used to model substation flow limit
$\theta_{(i,\,t)}^{bus}$	Voltage angle of bus i at time period t (rad)

incentives [7]. The DR programs can be broadly divided to price-base programs and incentive-based programs. In the price-based programs, the consumers will be provided by the real time or time of use prices and have the chance to manage energy use to lower the bill. There are no monetary payments in this type of the DRPs. In the incentive-based programs, the consumers will respond to network operation requests to lower energy consumption and then the operator will charge the consumer with monetary payments based on the quantity and quality of the consumers' participation. The degree of the peak load shaving by running DRPs is a function of the program type, i.e., quantity and quality of the participation in the programs. Implementing DRPs is not without challenges. The challenges are high investment cost for measurement and communication infrastructure, requiring new network simulation and dispatch models, and uncertain degree of consumer's willingness and participation in the programs [8].

Other method to postpone network reinforcement needs by shaving peak of the load profile is supplying the load locally [9–12]. Local power generation resources, known as Dispersed or Distributed Generation (DG), are small-scale power plants where can be located near of the load centers almost everywhere in the network. Besides peak load shaving, installing DG units can bring many benefits to the system including loss reduction, voltage quality improvement, reliability enhancement, energy cost and emission reduction (only for renewable resources), and so on [13–16]. The local resources can be totally categorized to dispatchable and non-dispatchable units. The dispatchable DG units is a type of resource in which output power can be regulated desirably based on the operator preferences and without uncertainty concerns [17]. Fossil-fired engines like diesel or small scale gas fired units are examples of these units. On the other hand, non-dispatchable units are generation resources based on the renewable energy wherein output power is a function of the stochastic input energy. In other word, generated power cannot be regulated easily and involves variability and also uncertainty of the input energy nature. Despite numerous benefits, renewable dispersed resources are characterized by the limited resource potential, non-dispatchability, and also low predictability features. In addition, fossil-fired resources are characterized by high energy costs and air pollutions. [18].

The energy needed in the peak time periods can be shifted to the other time periods with low energy demand and subsequently low energy prices [19]. In this method, extra energy in the off-peak periods will be stored to use in the time periods with high energy demand and high prices. In other word, shaving peak of load profile can be performed by filling the valley of the load profile. This task, peak shaving along with the valley filling, is known as load levelling or load flattening. To do this, an Energy Storage System (ESS) is needed. But, only some specific types of the ESSs can perform load leveling [20]. An ESS unit belongs to the one of the two main types. The first type of the ESS is that type of storage unit which can store energy for a short period of time and subsequently have a relatively short discharge duration. Discharge duration of this type of the ESS is in the range of millisecond to some minutes. These ESS technologies have a very fast response but cannot deliver energy for a long period of time and subsequently cannot use for energy management applications, namely load leveling. Flywheel Energy Storage (FES), Superconducting Magnetic Energy Storage (SMES), Supercapacitor (also known as Ultracapacitor), and some specific types of the batteries belong to this category. On the other hand, there is other type of the ESS units in which energy can be stored for a long period of time and subsequently have a relatively long discharge duration. Discharge duration of this type of the ESS is in the range of several hours or even days and weeks. This ESS type can be used for energy management applications for example load leveling and expansion deferral. Pumped Hydro Energy Storage (PHES), Compressed Air Energy Storage (CAES), hydrogen storage, and some types of the Battery Energy Storage System belong to this category. Regarding this fact that the PHES and CAES require specific geographic formations, they rarely installed in the distribution networks. Also, hydrogen storage and converting it back to the electricity by the fuel cells have some challenges including low efficiency and hydrogen storage concerns [21–23]. The BESS possesses many unique features and applications and have been installed in the distribution networks for various applications. Relatively high power and energy density, fast response, modularity, full control inverter interface, small footprint, carbon free systems, no environment manipulation, relatively high storage durability, and fast installation are of advantages of the batteries. One of the major applications of the BESS is load leveling. Leveling the load profile can postpone substation expansion needs by shaving the peak load. This is due to the fact that the substation usually faces overload at the peak hours of the peak days. Therefore, if it is possible to supply a portion of the peak load from another source, the substation loading will be reduced. The BESS can supply this required energy at peak hours with the energy stored previously at off-peak hours. The BESSs have been used for diverse applications in the electric power distribution networks. In [24–27], the BESSs are deployed to enhance reliability level of the network. In [28–30], they are utilized to reduce operation cost and voltage profile improvement simultaneously. Application of the storage devices to enhance profit of the distribution company (DISCO) in presence of the network uncertainty is addressed in [31]. The BESSs can be used to reduce distribution network losses. This is done in [32] by leveling the load profile. In [33] a general modeling and scheduling method is proposed for optimal BESS operation in the distribution networks. The model aims at reducing daily operation cost of the network by optimal control of the BESS. Finally, in [] they have been used for energy balance in addition to the grid support in [34]. Specific utilization of the BESS for substation expansion deferral is not addressed adequately in the literature. There is only a research work dealing with storage application to defer substation expansion plans. In [35] a combination of DG allocation along with BESS installation is proposed to defer substation expansion plans. In the proposed model, distributed generation resources in the form of wind farms are installed at the substation and batteries are used to store renewable energy. The model is non-linear and solved using genetic algorithm.

What is important is that the maximum level of the substation expansion deferral should be achieved in a way that does not increase cost of the network operation. In this context, this paper aims to propose an optimal operation scheduling for the BESSs installed at the distribution network for simultaneously substation investment deferral and also cost reduction. The proposed model is a Multi-Objective Mixed Integer Linear Programming (MOMILP) which benefits from linearity and also handling conflict objectives. The aim of the proposed model is to obtain the maximum expansion deferral percent with minimum costs of the network operation. The proposed operation method determines optimal charging and discharging scheduling of the active and reactive power of the installed BESSs. The optimization criterion is based on the planner preferences in term of the level of the expansion deferral and/or cost reduction percent. The proposed model considers various parts of the whole BESS including battery pack, inverter, and transformer. Also, active, reactive, and apparent power relations and interactions are modeled by a linearized version of the original AC power flow equations with a reasonable accuracy level. This means that effect of the reactive power contribution of the BESSs on the substation flow reduction is also taken into account. The model has the flexibility to deal with various degrees of the expansion deferral but ensuring minimum network operation cost. Contributions of the work can be listed as follows.

1 Proposing a BESS operation model aiming at substation expansion deferral with minimum cost
2 Multi-objective framework ensuring trade-off between level of the expansion deferral and also operation cost
3 Flexibility of the proposed model to deal with various degrees of the planner preferences
4 Considering effect of the reactive power contribution of the BESSs on the substation flow reduction.
5 Linear structure ensuring convergence to the global optima, easily solvable by strong commercial solvers, and also applicable to the real-life very large scale distribution networks.

The paper excluding this introduction is structured as follows. In Section 2, proposed BESS planning model is explained theoretically and mathematically. Then, in Section 3 the proposed model is implemented on a test case and results are discussed. Finally, Section 4 draws some conclusion remarks of the work.

2. Proposed model

In this section, the proposed method which is a Multi-Objective Mixed Integer Linear Program (MOMILP), is explained completely. In the first step, conceptual framework of the problem is described. Then, mathematical formulation of the proposed model is presented. Finally, solution procedure is explained.

2.1. Conceptual framework

The system under study and the BESSs installation location are illustrated in Fig. 1. As the figure shows, a sub-transmission substation is located between an up-stream sub-transmission network and associated

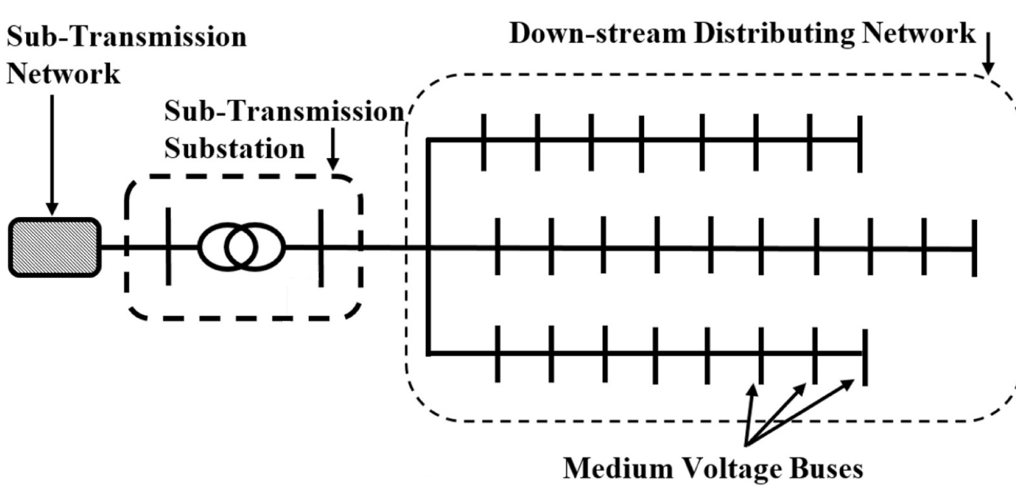

Fig. 1. Illustration of the system under study and the BESSs installation location

down-stream medium voltage distribution network. The problem is that the substation will reach its nominal values in the near future and cannot meet future load and power flow growth. Physical expansion of the substation equipments, mainly its transformer(s), is not possible in the near future and an expansion deferral plan should be adopted. To do this, the installed BESSs in the medium voltage buses of the down-stream distribution network can be scheduled optimally to alleviate the substation overload. The utilized scheduling method should not cause increasing network operation cost.

It should be noted that the BESSs are normally scheduled in order to minimize the daily operation cost of distribution network. In the conditions described above, namely critical peak days, the paradigm of the network operation should be changed and such that consider substation expansion deferral in addition to the cost of the network operation. Therefore, a new scheduling model needs to be used for this condition. For this purpose, a new model will be proposed and presented. The proposed model is a multi-objective optimization problem that pursues two objectives. The first one is to minimize the daily operating cost similar to the conventional operation case. The second one is to postpone expansion of the substation by minimizing the power flow. As it can be observed in the following, and the results of the simulations show, these two objectives are in conflict with each other except for a very small area, and improving one requires destroying the other. Therefore, it is necessary that the best result be achieved by correctly defining the problem and also solution method. Finally, it should be noted that the operator decision variable in hand in this problem is the charge and discharge power in addition to the resultant energy stored in the BESSs so that with their optimal control they can achieve the desired goal.

2.2. Mathematical formulation

As mentioned earlier, objective functions of the problem are maximizing substation expansion deferral and minimizing network operation cost. Maximizing substation expansion deferral can be achieved by minimizing the flow passing the substation over the time. This is mathematically formulated in (1). As it is shown, in order to postpone substation expansion needs to a later time, maximum apparent power flowing through it should be minimized. This is the first objective of the problem.

$$\underset{t}{Min}\left(\underset{t}{Max}\ SS_{(t)}^{Flow}\right) \tag{1}$$

The objective function formulated in the above, should be achieved with the minimum cost. In other word, second objective of the problem is minimizing the total operation cost, as formulated in (2).

$$Min\ C_{Tot} \tag{2}$$

Total operation cost is the money paid to the up-stream network for the power injected to the substation summed up over all of the time periods. It is supposed that this cost term adopts a stair-wise shape wherein the power cost increases with the consumption growth, as denoted by (3). This is, in fact, a piece-wise linearization of the original non-linear quadratic cost function. An example of the power cost curve is depicted in Fig. 2 where this is a common practice to model power cost by a set of linear terms [36–37]. In this way, the total power injected by the substation to the network is equal to the summation over all of the power blocks used, as declared in (4).

$$C_{Tot} = \sum_{t}\sum_{m=1}^{M} CS_{(m)}^{block}\, PS_{(t,m)}^{block} \tag{3}$$

$$PS_{(t)}^{G} = \sum_{m=1}^{M} PS_{(t,m)}^{block}\ \ \forall\ g \in \Psi_G,\ t \in \Psi_T \tag{4}$$

Power flow impact of each BESS in the installation bus can be simultaneously considered as a fictitious load in addition to a fictitious generator. The fictitious load simulates charging mode of the BESS while the fictitious generator mimics discharging mode of the BESS. Considering that the BESS can absorb or inject both active and reactive power, both active and reactive power balance equations will be affected. Thus, in the BESS installation bus, power balance equation for active power and reactive power can be formulated as (5) and (6), respectively.

$$PB_{(i,\,t)}^{Ch} + P_{(i,\,t)}^{D} + \sum_{j} P_{(i,j,\,t)}^{L} = PB_{(i,\,t)}^{Di}\quad \forall\ t \in \Omega_T,\ ij \in \Omega_I,\ i \neq 1 \tag{5}$$

$$QB_{(i,\,t)}^{Ch} + Q_{(i,\,t)}^{D} + \sum_{j} Q_{(i,j,\,t)}^{L} = QB_{(i,\,t)}^{Di}\quad \forall\ t \in \Omega_T,\ ij \in \Omega_I,\ i \neq 1 \tag{6}$$

In the substation bus of the network, which is the first bus of the network, the load demand is equal to zero and the power balance for the active and reactive powers can be calculated by (7) and (8), respectively.

$$PB_{(i,\,t)}^{Ch} + \sum_{j} P_{(i,j,\,t)}^{L} = PS_{(t)}^{G} + PB_{(i,\,t)}^{Di}\quad \forall\ t \in \Omega_T,\ ij \in \Omega_I,\ i = 1 \tag{7}$$

$$QB_{(i,\,t)}^{Ch} + \sum_{j} Q_{(i,j,\,t)}^{L} = QS_{(t)}^{G} + QB_{(i,\,t)}^{Di}\quad \forall\ t \in \Omega_T,\ ij \in \Omega_I,\ i = 1 \tag{8}$$

The apparent power flow leaving the substation can be calculated by (9) at any time period. This power flow, output power of the substation, should not exceed power rating of the substation, as stablished in (10). It should be noted that, in order to defer expansion plans, this power should be leveled by means of the BESSs.

$$SS_{(t)}^{Flow} = \sqrt{(PS_{(t)}^{G})^2 + (QS_{(t)}^{G})^2}\quad \forall\ t \in \Omega_T \tag{9}$$

$$SS_{(t)}^{Flow} \leq SS^{Rating}\quad \forall\ t \in \Omega_T \tag{10}$$

The equation presented in (9) is non-linear. The non-linearity can be removed by using a mathematical method to convert the original non-linear equation to a set of linear equations. The non-linear equation presented in (9) can be interpreted as locus of a set of the points inside a circle with radius SS^{Flow}, as depicted in Fig. 3.

The figure demonstrates relation between active/reactive charging /discharging powers with the installed power rating. In order to eliminate non-linearity in the equation, a transformation from the initial flow limit circle equation is utilized. The binding circle can be replaced approximately by a set of straight line. Set of the approximating straight

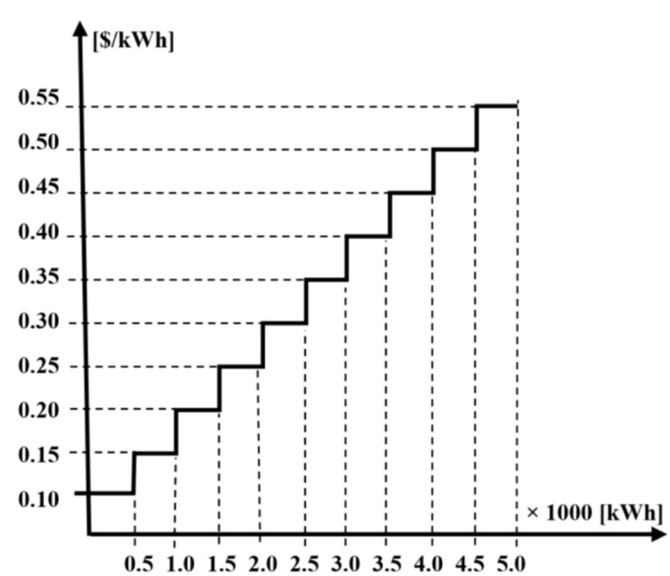

Fig. 2. An example of the stair-wise cost function of the substation

Table 1
Line and load data of IEEE 33-bus distribution test system

Line location		Line parameters		Bus loads at receiving bus	
Sending bus	Receiving bus	R (Ω)	X (Ω)	P (kW)	Q (kvar)
1	2	0.0922	0.047	100	60
2	3	0.493	0.2511	90	40
3	4	0.366	0.1864	120	80
4	5	0.3811	0.1941	60	30
5	6	0.819	0.707	60	20
6	7	0.1872	0.6188	200	100
7	8	0.7114	0.2351	200	100
8	9	1.03	0.74	60	20
9	10	1.044	0.74	60	20
10	11	0.1966	0.065	45	30
11	12	0.3744	0.1238	60	35
12	13	1.468	1.155	60	35
13	14	0.5416	0.7129	120	80
14	15	0.591	0.526	60	10
15	16	0.7463	0.545	60	20
16	17	1.289	1.721	60	20
17	18	0.732	0.574	90	40
2	19	0.164	0.1565	90	40
19	20	1.5042	1.3554	90	40
20	21	0.4095	0.4784	90	40
21	22	0.7089	0.9373	90	40
3	3	0.4512	0.3083	90	50
23	24	0.898	0.7091	420	200
24	25	0.896	0.7011	420	200
6	26	0.203	0.1034	60	25
26	27	0.2842	0.1447	60	25
27	28	1.059	0.9337	60	20
28	29	0.8042	0.7006	120	70
29	30	0.5075	0.2585	200	600
30	31	0.9744	0.963	150	70
31	32	0.3105	0.3619	210	100
32	33	0.341	0.5302	60	40

Table 2
Hourly load factors [%]

Hour	1	2	3	4	5	6
Factor	67	63	60	59	59	60
Hour	7	8	9	10	11	12
Factor	74	86	95	96	96	95
Hour	13	14	15	16	17	18
Factor	95	95	93	94	99	100
Hour	19	20	21	22	23	24
Factor	100	96	91	83	73	63

Table 3
Total results of the simulations for various cases

Scenario description	Scenario title	Operation cost ($)	Maximum SS flow kW	%
Without storage	S00	20,668	4954	99.086
Conventional cost-based	S11	19,767	3821	76.435
Proposed multi-objective model	S21	19,767	3650	73.012
	S22	19,787	3607	72.145
	S23	**19,806**	**3592**	**71.850**
	S24	19,826	3580	71.613
	S25	19,845	3575	71.511
	S26	19,865	3575	71.511
	S27	19,885	3575	71.511

lines constitute a convex regular polygon with k sides, as illustrated in the figure. Each straight line will be defined by a linear equation. By defining linear equation of the lines and then using some simplification and manipulation, linearized apparent power flow equation and limit can be stated as (11) and (12).

$$SS_{(m,t)}^{Linear} = \frac{\mathrm{Cos}\frac{(2m-1)\pi}{M} PS_{(t)}^{G} + \mathrm{Sin}\frac{(2m-1)\pi}{M} QS_{(t)}^{G}}{\mathrm{Cos}\,(\pi/M)} \quad \forall \quad m \in \Omega_m\,, \quad t \in \Omega_T \tag{11}$$

$$SS_{(m,t)}^{Linear} \le SS^{Rating} \quad \forall\ t \in \Omega_T \tag{12}$$

In (11) and (12), lowercase k indicates number of each side or straight line where uppercase k stands for the number of the approximating sides. The required number of the sides is a predefined value such that increasing the lines will enhance the accuracy of the approximation at the expense of the simulation time. Considering that power flow of the substation is one of the objective functions of the problem, the new linearized flow should be used. In other word, the first objective function of the problem presented in (1) is replaced with the linearized version of the flow, as denoted by (13).

$$\underset{m,t}{Min}\left(\underset{m,t}{Max}\ SS_{(m,t)}^{Linear}\right) \tag{13}$$

Considering that the emerging battery storage systems are integrated with the grid by means of the sophisticated power converters, they can inject/drawn reactive power besides active power. This means that the BESS can contribute to the reactive power management in the distribution grid at the time periods with negligible or zero active power exchange. Reactive power contribution of the BESS can reduce apparent power flow and loading of the substation considerably. This means that proper modeling of the reactive power exchange of the BESS can enhance level of the substation expansion deferral by eliminating output reactive power. To do this, Fig. 4 demonstrates a generic BESS system including battery pack, conversion unit, and transformer(s).

The charging and discharging actions take place only in the battery pack which is a DC unit inherently. The battery pack is responsible for the absorbing and injecting power when needed. In order to communicating the battery pack with the grid, a power conversion unit (PCU) is needed considering that the grid is mainly AC. The PCU acts as a rectifier in the BESS charging mode by converting grid AC power to the DC power of the battery pack. On the other hand, the PCU in the discharging mode converts stored DC power of the battery pack to the grid AC by inverter function. If output voltage of the inverter does not match installation bus nominal voltage, a transformer (or bank of transformers) is needed to step-up the voltage. It should be noted that power flow across BESS components should not exceed nominal values. In addition, energy capacity of the BESS is a limited value. These interactions convey some important properties of the BESS which should be modeled properly. The characteristics are as follows:

1 If a BESS is installed at a bus, then the corresponding installation binary variable will be equal to zero and it can interact with the grid. It should be noted that, it can perform only one of the charging and discharging actions at any time period. In other word, the BESS cannot charge and discharge simultaneously in a time period. This situation is modeled by using two binary variables each indicating one of the charging and discharging actions. The BESS can only choose one of the binary variables, charging or discharging actions, at any time period as modeled in (14)–(16) for active power. It should be noted that the BESS can perform the charging action if only it is installed at the bus and also the corresponding binary variable is set to one. In (17)–(19) a similar situation is established for the charging and discharging reactive powers of the BESS.

$$BP_{(i,t)}^{Ch} + BP_{(i,t)}^{Di} \le BI_{(i)} \quad \forall \quad t \in \Omega_T\ ,\ i \in \Omega_I \tag{14}$$

$$PB_{(i,t)}^{Ch} \le BP_{(i,t)}^{Ch}\, PB_{(i)}^{Rate} \quad \forall \quad t \in \Omega_T\ ,\ i \in \Omega_I \tag{15}$$

Table 4
The CRI and EDI and their difference for various cases

Scenario title	CRI (%)	EDI (%)	Difference (%) (S2–S11) CRI	EDI
S00	0	00.914	0	0
S11	4.359	23.565	0	0
S21	4.359	26.988	0	+3.423
S22	4.263	27.855	−0.100	+4.290
S23	**4.168**	**28.150**	**−0.200**	**+4.585**
S24	4.072	28.387	−0.299	+4.822
S25	3.980	28.489	−0.394	+4.924
S26	3.886	28.489	−0.492	+4.924
S27	3.785	28.489	−0.596	+4.924

$$PB^{Di}_{(i,t)} \leq BP^{Di}_{(i,t)}\, PB^{Rate}_{(i)} \quad \forall \;\; t \in \Omega_T\;,\; i \in \Omega_I \tag{16}$$

$$BQ^{Ch}_{(i,t)} + BQ^{Di}_{(i,t)} \leq BI_{(i)} \quad \forall \;\; t \in \Omega_T\;,\; i \in \Omega_I \tag{17}$$

$$QB^{Ch}_{(i,t)} \leq BQ^{Ch}_{(i,t)}\, PB^{Rate}_{(i)} \quad \forall \;\; t \in \Omega_T\;,\; i \in \Omega_I \tag{18}$$

$$QB^{Di}_{(i,t)} \leq BQ^{Di}_{(i,t)}\, PB^{Rate}_{(i)} \quad \forall \;\; t \in \Omega_T\;,\; i \in \Omega_I \tag{19}$$

2 The charging and discharging powers of the BESS should not go beyond the installed values. It is worth mentioning that the power rating of the whole BESS is a value related to the battery pack, PCU, and also the transformer. The power rating of the battery pack is a DC value while the PCU and transformer power rating are based on the apparent power which is a AC value. Overall power rating of the installed BESS should consider abovementioned remarks and will constitute an upper bound for all of the power interaction of the system. Power exchange limitation for active charging, active discharging, reactive charging, and reactive discharging power has already been mathematically considered in (15) and (16) and (18) and (19), respectively.

3 The stored energy in the BESS is limited to the installed energy capacity, as denoted by (20). It should be noted that the energy rating of the installed BESS is only related to the battery pack. Additionally, drawn power from the BESS in the discharging mode cannot exceed stored energy multiplied by the discharging efficiency and also divided by the time step. This is mathematically expressed in (21). In this equation, ΔT which is a constant value denotes the time step of the modeling.

$$E^{BESS}_{(i,t)} \leq EB^{Rate}_{(i)} \quad \forall \;\; t \in \Omega_T\;,\; i \in \Omega_I \tag{20}$$

$$PB^{Di}_{(i,t)} \leq E^{BESS}_{(i,t)}\, \eta^{Di}/\Delta T \quad \forall \;\; t \in \Omega_T\;,\; i \in \Omega_I \tag{21}$$

4 The energy stored in the BESS at any time period is a function of the remained energy, charging power, and discharging power of the system at the previous time period. Furthermore, charging and discharging efficiency associated with the corresponding action should be considered, as presented in (22). Also, the battery starts time steps with a predefined state of charge and ends them with the same value. These situations are mathematically expressed in (23) and (24).

$$E^{BESS}_{(i,t)} = E^{BESS}_{(i,t-1)} + PB^{Ch}_{(i,t-1)}\, \eta^{Ch} - PB^{Di}_{(i,t-1)}/\eta^{Di} \quad \forall \;\; t \in \Omega_T\;,\; i \in \Omega_I \tag{22}$$

$$E^{BESS}_{(i,t)} = E^{BESS}_{ini} \quad \forall \;\; t = t_{ini}\;,\; i \in \Omega_I \tag{23}$$

$$E^{BESS}_{(i,t)} = E^{BESS}_{ini} \quad \forall \;\; t = t_{end}\;,\; i \in \Omega_I \tag{24}$$

5 Although active and reactive power flow limitations have been considered previously, flow limitation on the apparent power should also be taken into account. Original apparent power flow can be calculated as (25).

$$\sqrt{(PB^{Net}_{(i,t)})^2 + (QB^{Net}_{(i,t)})^2} \leq PB^{Rate}_{(i)} \quad \forall \;\; t \in \Omega_T\;,\; i \in \Omega_I \tag{25}$$

In (34), $PB^{Net}_{(i,t)}$and $QB^{Net}_{(i,t)}$ stand for the net active and reactive power exchange of the BESS with the grid. It should be noted that, each of these variables is composed of one of the charging or discharging variables. Considering that the BESS is enforced to do only one of the charging and discharging actions at any time periods, the net power exchange can be defined as formulated in (26) and (27).

$$PB^{Net}_{(i,t)} = (PB^{Ch}_{(i,t)} - PB^{Di}_{(i,t)}) \quad \forall \;\; t \in \Omega_T\;,\; i \in \Omega_I \tag{26}$$

$$QB^{Net}_{k} = (QB^{Ch}_{(i,t)} - QB^{Di}_{(i,t)}) \quad \forall \;\; t \in \Omega_T\;,\; i \in \Omega_I \tag{27}$$

Eqs. (26) and (27) state that net values of the active and reactive power of the BESS will be equal to the one of the charging and discharging value at any time period. The non-linear equation in (25) is transformed to a set of linear equations and treated in a similar way to the substation flow limit which is described previously (Fig. 3). The equivalent approximated linear equation is as follows.

$$\frac{\mathrm{Cos}\frac{(2m-1)\pi}{M} PB^{Net}_{(i,t)} + \mathrm{Sin}\frac{(2m-1)\pi}{M} QB^{Net}_{(i,t)}}{\mathrm{Cos}\,(\pi/M)} \leq PB^{Rate}_{(i)} \quad \forall \;\; m \in \Omega_m\;,\;\; t \in \Omega_T \tag{28}$$

Finally, Active and reactive power flow between network busses are modeled by (29) and (30). These equations are linear version of the original AC Newton Raphson method. Details of the linearization and other issues related to the degree of the accuracy are out of the scope of this paper and can be found in [38].

$$\begin{aligned} P^{L}_{(i,j\,,\,t)} = G^{L}_{(i,j)}(V^{sqr}_{(i,\,t)} - V^{sqr}_{(j\,,\,t)}) - G^{L}_{(i,j)}(\theta^{bus}_{(i,\,t)} - \theta^{bus}_{(j\,,\,t)}) \\ + G^{L}_{(i,j)}\left(\frac{(\theta^{bus}_{(i,\,t)} - \theta^{bus}_{(j\,,\,t)})^2}{2}\right) \quad \forall \; t \in \Omega_T,\; ij \in \Omega_I \end{aligned} \tag{29}$$

$$\begin{aligned} Q^{L}_{(i,j\,,\,t)} = -B^{L}_{(i,j)}(V^{sqr}_{(i,\,t)} - V^{sqr}_{(j\,,\,t)}) - G^{L}_{(i,j)}(\theta^{bus}_{(i,\,t)} - \theta^{bus}_{(j\,,\,t)}) \\ - B^{L}_{(i,j)}\left(\frac{(\theta^{bus}_{(i,\,t)} - \theta^{bus}_{(j\,,\,t)})^2}{2}\right) \quad \forall \; t \in \Omega_T,\; ij \in \Omega_I \end{aligned} \tag{30}$$

2.3. Solution procedure

The proposed multi-objective model formulated in the previous subsection should be solved by a proper solution method. Before solving the model, the first objective formulated in (1) and then changed in (13), should be reformed in such a way that can be handled by the problem. In other word, the min-max function should be reformulated as a single minimum or maximum function. To this end, the objective presented in (13) is replaced with (31) and (32). The newly added auxiliary variable λ help to find the minimum of the maximum flow passing through the substation.

$$Min\,\lambda \tag{31}$$

$$SS^{Linear}_{(m,t)} \leq \lambda \tag{32}$$

Considering various reformulations presented in the above, the final

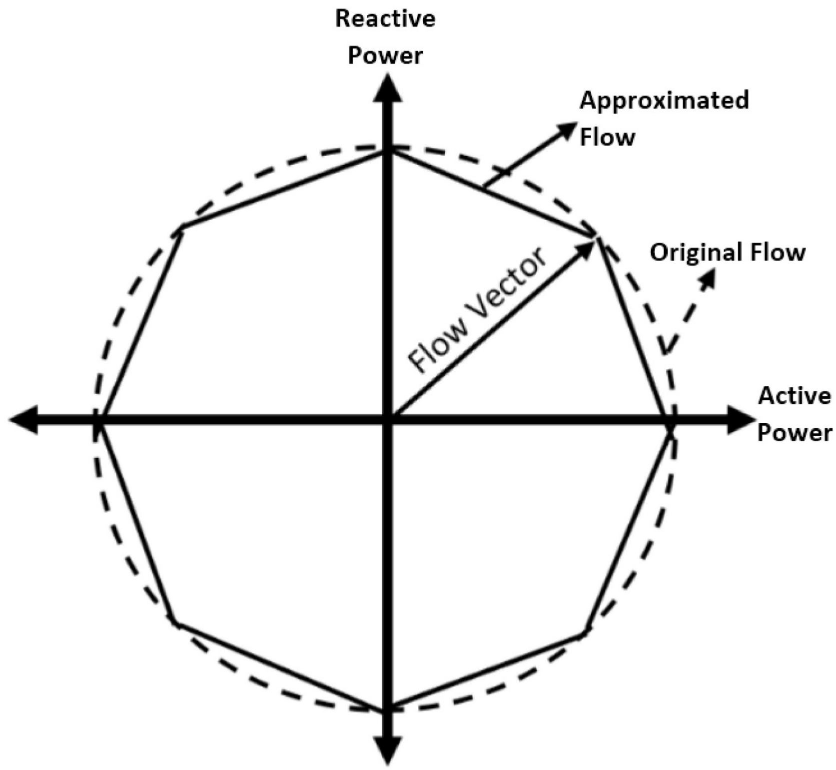

Fig. 3. Approximation of the substation flow by envelope polygon

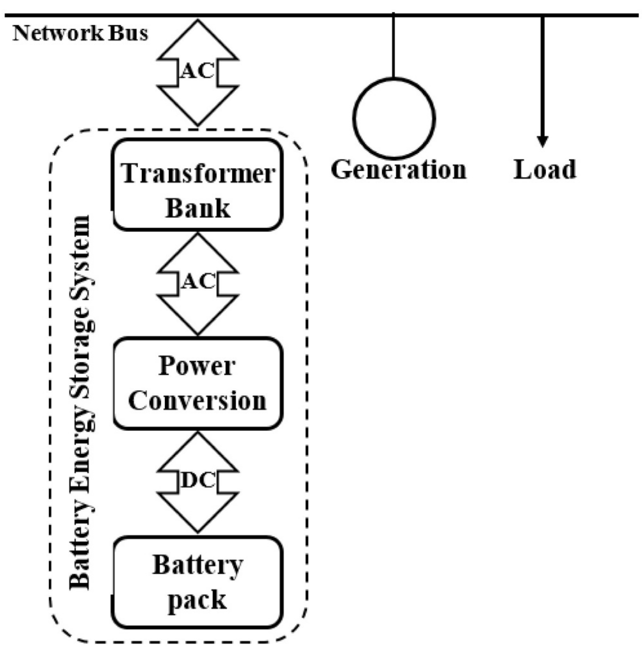

Fig. 4. A generic BESS installed at one of the system buses

multi-objective model can be expressed as:

$$Min\,\lambda\ ,\ \ Min\,C_T$$
$$Subjected\ to:\begin{cases}(3-8)\\(11-12)\\(14-24)\\(26-30)\\(32)\end{cases}\qquad(33)$$

The proposed MOMILP model formulated in (33) aims at minimizing substation flow but with minimum operation cost and considering various network and the BESSs constraints and properties.

Finding solution of an optimization problem having only an objective function is a relatively simple and straightforward task because the result is the optimal solution. On the contrary, in the Multi-Objective Optimization (MOO) there is at least two different, conflicting, and non-homogeneous objective functions where no single optimal solution can be fine so that all the objective functions simultaneously optimize. In this situation, the “most preferred” solution should be adopted based on the value of the objectives. In the MMO the optimality concept will be substituted with the efficiency concept. The efficient solutions, also known as Pareto optimal, non-dominated, or non-inferior solutions are those solutions wherein cannot be improved further in one of the objective functions without deteriorating at least one of the remained ones. Mathematical concept of these solutions is depicted in Fig. 5. It should be noted that, none of the efficient solutions can be regarded as the best one without additional information which can be provided by the decision maker.

Based on the classification made by the Hwang and Masud [39], the solving methods of the MMO problems are categorized into three main methods including a-priori methods, a-posteriori methods, and interactive methods. The difference between these methods is in the stage in which the decision maker involves in the decision making process. In the a-priori methods, the decision maker determines the preferences before the solution process begins. The drawback of this method is that it is difficult for the decision maker to know earlier and accurately quantify his/her preferences. In the interactive methods, an interaction will be made between the decision maker and the solution process by interchanging phases of dialogue with the decision maker with the phases of the solution calculation. The weakness is that the decision maker cannot observe the whole picture of the solutions.

In the generation or a-posteriori methods, all of the efficient solutions of the problem or a sufficient representation of them are calculated in the first stage. Afterwards, the decision maker is called to choose his/her the most preferred one among all of the solutions. These

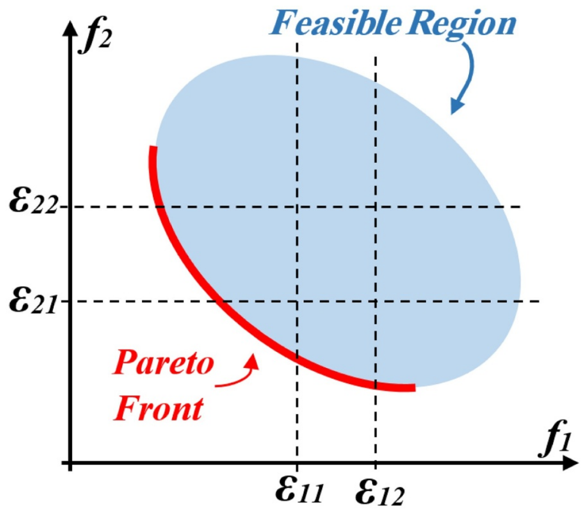

Fig. 5. Graphical presentation of efficient solutions and the ε-constraint method

methods possess some important advantages. The solution process will be divided into two phases namely generation of the efficient solutions and involvement of the decision maker when all of the solutions is on the table. Considering that the decision maker is involved only in the second phase, all of the possible alternatives or efficient solutions of the MMO are available only in the end of the first stage. Consequently, they are some compromised solutions whenever the decision maker is hardly available or the interaction with him/her is problematic.

In general, the weighted sum approach (WSA) and the ε-constraint method are the most widely used generation methods. In the WSA method, a single objective function formed by the weighted sum of the objective functions will be optimized. The objective functions should be normalized based on their sole optimal values so as to be comparable by the weights. In the ε-constraint method, one of the objective functions will be optimized using the other objective functions as constraints. In other word, other objective functions will be incorporated in the constraint part of the model as shown below:

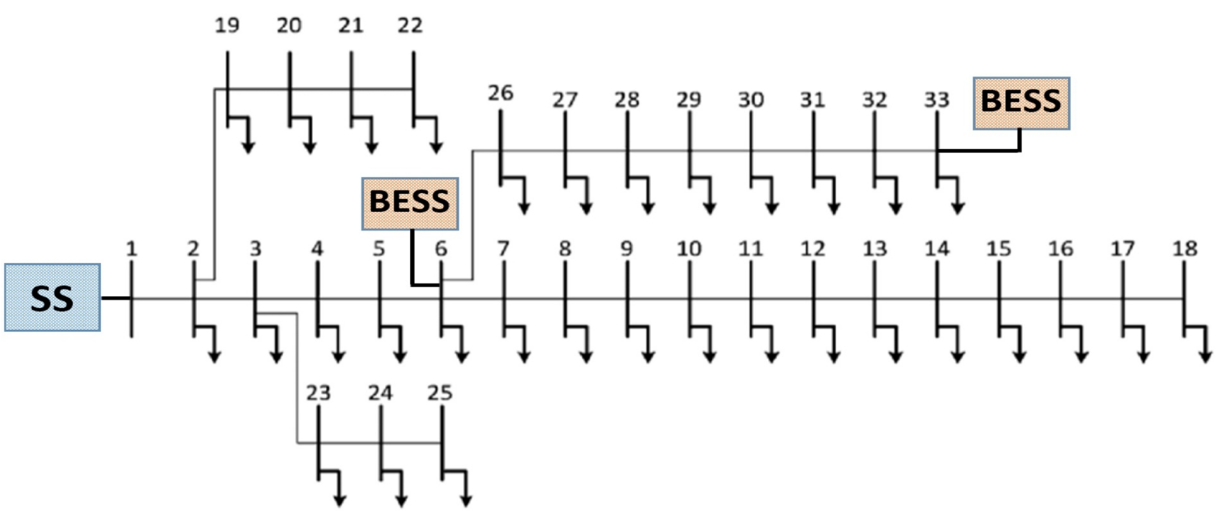

Fig. 6. Single line diagram of the IEEE 33-bus distribution test system

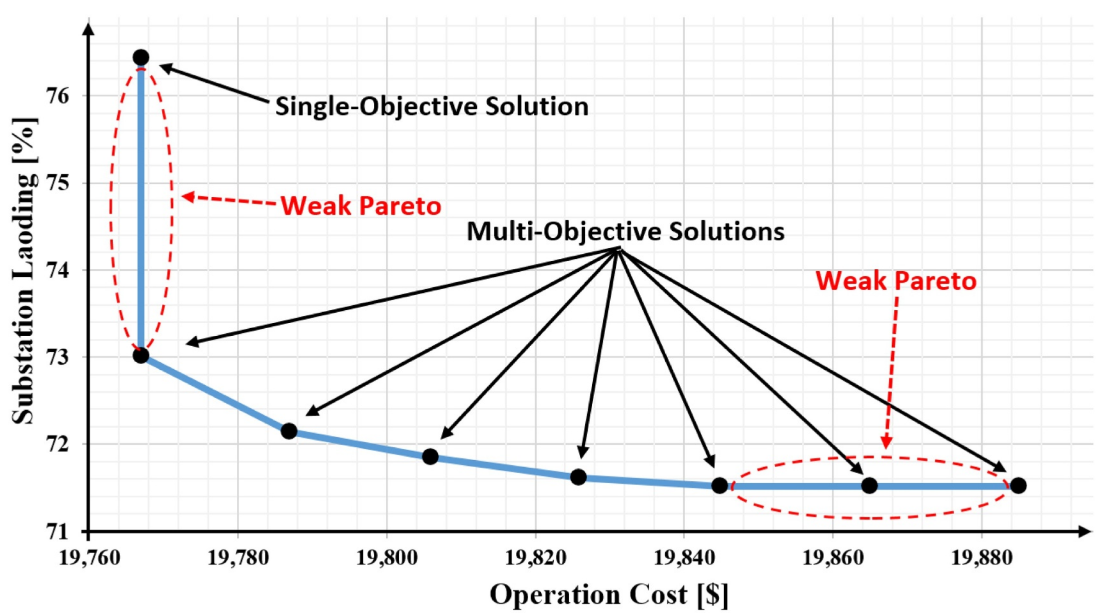

Fig. 7. Pareto front of the multi-objective solution

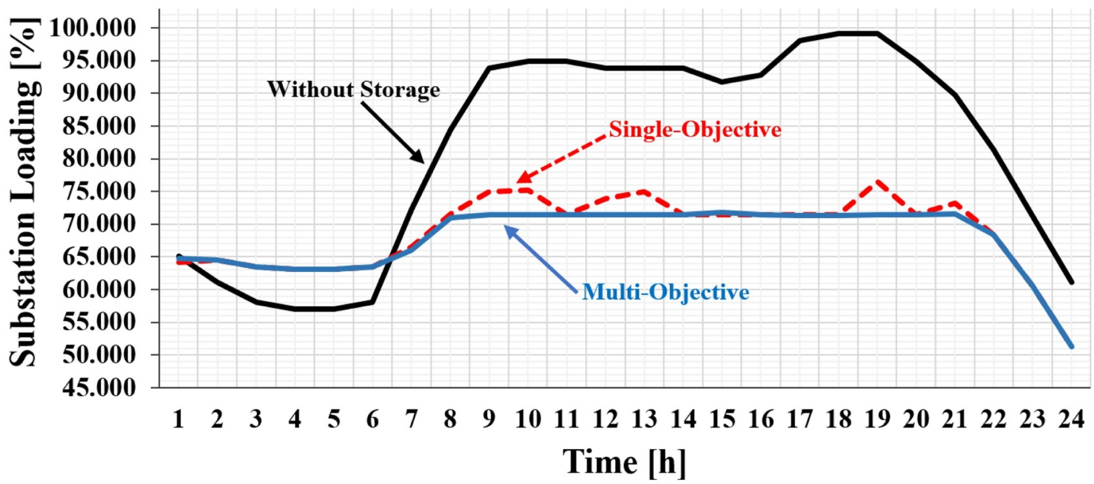

Fig. 8. Substation power flow for various cases

$$\begin{aligned}&\underset{x}{Min}\ f_i(x)\\&st\!:\ x\in X\\&f_j(x)\le \varepsilon_j\,,\ j\ne i\end{aligned} \tag{34}$$

By parametrical variation in the RIGHT Hand Side (RHS) of the constrained objective functions or ε_j, the efficient solutions of the problem will be found, as illustrated in Fig. 5. The ε-constrained method has several advantages over the WSA method. To solve the proposed MOO model, the ε-constraint method is used. The reason is the functionality and power of the method to handle various conflict objectives. This feature has led to widespread use of this method to solve multi-objective models in the literature [40].

3. Case study

The model proposed in the previous section is implemented on a test case to evaluate its efficiency. The 33-bus distribution test system is used as the test system [41]. Single line diagram of the system along with the substation and BESSs installation location are depicted in Fig. 6. As in the figure, two BESSs each with 1500 kW of power rating and 2000 kWh of energy capacity are installed at buses 6 and 33 of the network. Line data in addition to the bus loadings are presented in Table 1. Similar to the original network proposed in [41], the network is supplied only with the up-stream sub-transmission substation which is connected to the sub-transmission network, in turn. The rated power of the substation is equal to the 5000 kW. A peak day consist of 24 h is considered for the simulations where hourly load factors are presented in Table 2 [42]. The model is implemented in the GAMS 24.9.2 [43] environment and is solved using CPLEX 12.4 [44] solver.

In order to evaluate efficiency of the proposed method, various scenarios are defined. The scenario titled by S00 denotes a case wherein there is not any BESSs in the network. In other word, in S00 scenario a conventional distribution network without storage devices is simulated. The S11 scenario stands for a single-objective cost-based BESS operation situation. In this case, the BESSs are only scheduled to reduce operation cost as much as possible. The scenarios named S21–S27 are multi-objective cases based on the proposed method for substation expansion deferral. These scenarios (S2X) are Pareto front solutions obtained by the method described in the previous section. Also, two new indexes are defined and calculated for each scenario to better compare the results. The Cost Reduction Index (CRI) is a measure of the scenario's cost reduction level with respect to the case without the BESSs, namely S11 scenario. This is calculated by (35) where *Cost** is the operation cost of the network in the S00 scenario. The Expansion Deferral Index (EDI) is a measure of the scenario's substation expansion deferral

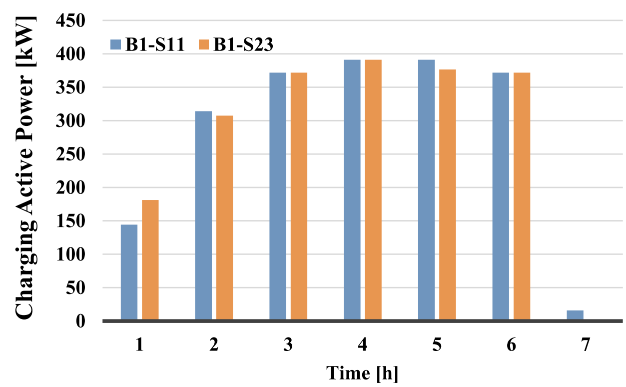

Fig. 9. Charging active power of the B1 battery for cases S11 and S23

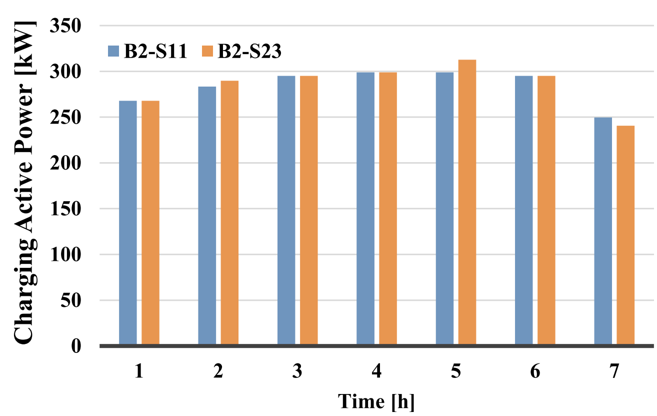

Fig. 10. Charging active power of the B2 battery for cases S11 and S23

level with respect to the rated capacity of the substation. This is calculated in (36) where SS^{Rating} and λ denote substation rated power and maximum flow of the substation over all of the time periods, respectively.

$$CRI = \frac{Cost - Cost^*}{Cost^*}\times 100 \tag{35}$$

$$EDI = \frac{SS^{Rating} - \lambda}{SS^{Rating}}\times 100 \tag{36}$$

With the new defined indexes, i.e. CRI and EDI, each multi-objective scenario can appropriately compare with the single-objective solution.

Total results of the simulation for various cases are shown in Table 3. The table reports scenario description, scenario title, total operation cost, and the maximum flow of the substation in kilowatts and percent. As in the table, the case without storage devices (S00) possesses the highest operation cost due to the considerable difference between peak and off-peak load demand.

Also, this case is recognized with the highest substation flow, namely 4954 KW. This means that the substation is very close to the rated power with 99.086% of operation. In the next case, S11 scenario, the total operation cost of the network is reduced to 19,767 dollars. This is also accompanied with the substation flow reduction. The substation maximum flow at the peak hours is reduced to 3821 equal to the 76,435% of its capacity. As the results denote, deploying the BESSs help to decreased operation cost and increase substation unused capacity, simultaneously. these benefits can be improved by using the proposed method without deteriorating each one. The results of scenarios S21–S27 are for the multi-objective cases. As the results demonstrate, more reduction in the substation maximum flow can be achieved at the expense of the increasing operation cost. In these scenario, the scenario S23 have a good situation in terms of the both operation cost and also substation maximum flow. Table 4 demonstrates the CRI and Edi for various case. By using this table, the network operator can easily decide on the optimal scenario among the efficient solutions obtained from the multi-objective model. The case wherein the both indexes possess the highest values is the best solution. Although this is not achievable in a multi-objective decision making, the solution with the best similar situation can be determined based on the operator's preferences. As in the table, the S00 scenario has the lowest CRI and EDI values and is therefore the worst case.

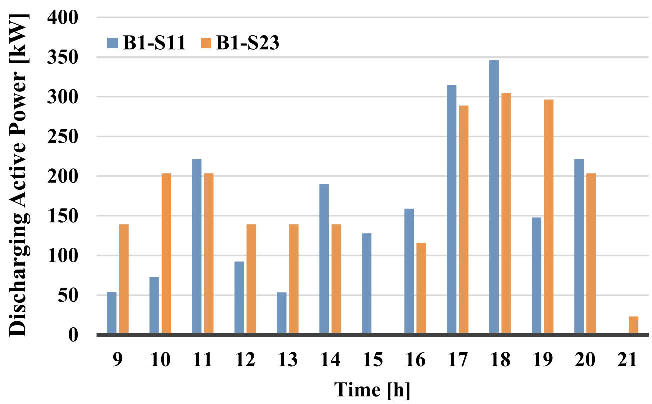

Fig. 11. Discharging active power of the B1 battery for cases S11 and S23

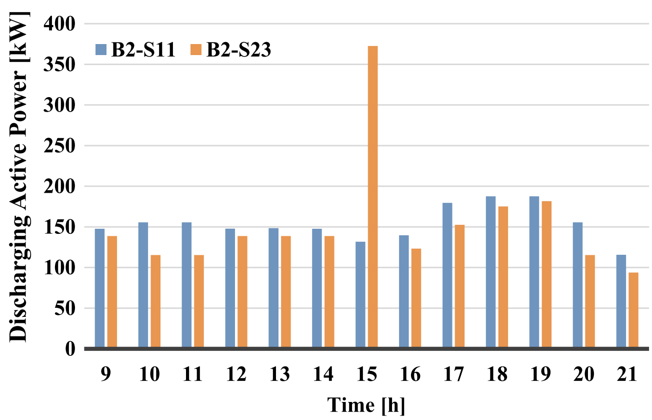

Fig. 12. Discharging active power of the B2 battery for cases S11 and S23

Although the S11 has the best CRI value, but, its EDI value is the worst case among the cases with the BESSs installed in the network, namely S11 and S21–S27. By using the proposed method, the network operator can achieve more on the EDI at the expense of the operation cost growth. As in the table, the S21 scenario, yield 3.423% more EDI without deteriorating CRI. This is valuable for the network operator considering that more expansion deferral is achieved with the maximum level of the network operation cost reduction. In the S23 scenario which is highlighted in the table, the EDI can be increased to 4.585% (1.162% more than the S11) at the expense of the only 0.2% increment in the cost reduction. Higher levels of the EDI can be preferred by the network operator in the cases with higher substation loading and risk of the overload. The model has the flexibility to deal with various degree of the desired EDI and CRI values with respect to the operation situation.

The Pareto Front of the multi-objective solutions along with the single-objective solution of the S11 scenario are depicted in Fig. 7. As the figure illustrates, the single-objective solution yield the lowest operation cost result. However, this value can be yielded but with a lower level of the substation loading (higher EDI). This is done by employing the proposed multi-objective model, as denoted by the single-objective solutions in the figure. As the figure demonstrates, for the first solution of the multi-objective model, namely S21, the substation maximum loading is diminished considerably without worsening the operation cost reduction level. This is due to the weak Pareto area in the curve. In the weak Pareto area, one solution can be further improved without deteriorating other solutions best results. Although, the occurrence of a weak Pareto in the solutions curve is not always the case and is related to the problem input and situation, other multi-objective solutions will

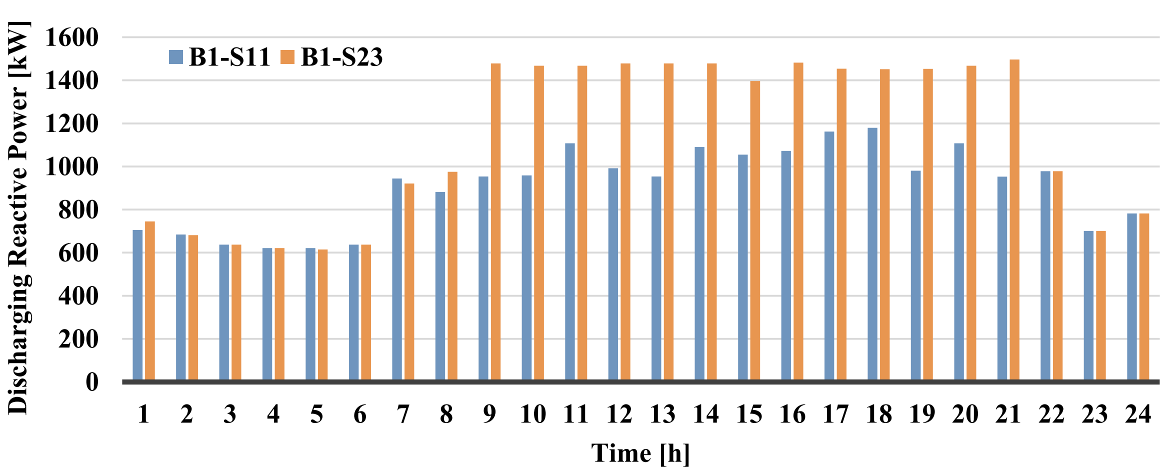

Fig. 13. Discharging reactive power of the B1 battery for cases S11 and S23

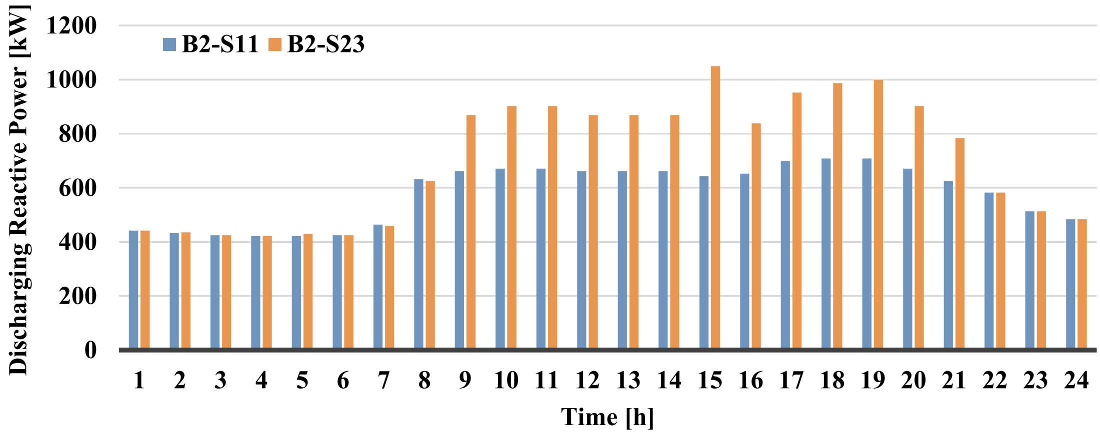

Fig. 14. Discharging reactive power of the B2 battery for cases S11 and S23

result in a further reduction in the substation loading for a very small increase in the operating cost.

Substation loading at each time period for various cases is depicted in Fig. 8. The figure shows the apparent power flow for cases without storage (S00), with storage but cost-based single-objective model (S11), and one of the multi-objective solutions (S23). As the figure denoted, the use of BESSs has led to a significant reduction in the substation loading. The figure also shows that this reduction can be further enhanced by scheduling the batteries according to the proposed method described above.

In the last but not the least, the charging active power is shown in Figs. 9 and 10 for BESS1 and BESS2, respectively. Also, Figs. 11 and 12 present the discharging active power of the BESSs. The figures compare the powers in the S23 case with the same variable in the S11 model. As the figures indicate, there is a difference between the power for the cases. The difference for the discharging power is more the charging power. These differences are the key parameter of the BESSs to achieve defined goals. In other word, the BESSs obtain more EDI with optimal control of these powers. Besides active power, reactive power of the BESSs has a significant impact on the results. Active power charging of the BESSs for all the cases and time periods is equal to zero and therefore is not depicted. Figs. 13 and 14 show the discharging reactive power of the both BESSs for S11 and S23 cases. As the figure re-presents, in the multi-objective case the BESSs inject more reactive power to the grid. This helps to compensate local reactive power demand and consequently lessening reactive power flow coming from the substation. This reduction in the reactive power will result to reduction of the apparent power flow of the substation, in turn.

4. Conclusions

Continuous electric energy consumption growth necessitates power system expansion. To do this, substation expansion is inevitable as one of the integral parts of the system. Various technical, economic, land, and environmental limitations signify importance of the substation expansion deferral plans. Utilizing energy storage units is on the practical methods to lessen substation loading at peak periods. To this end, a new method is proposed in this paper to optimally schedule batteries installed in order to achieve maximum expansion deferral. The proposed model is a multi-objective optimization which seeks to obtain minimum substation flow ensuring minimum operation cost. Results of the simulation in various cased demonstrate that substation expansion deferral can be more achieved without operation cost increase. Also, more expansion deferral can be yielded based on the network operator preferences with a negligible growth in the total operation cost.

Declaration of Competing Interest

None.

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