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# A Demand-Side Management-Based Model for G&TEP Problem Considering FSC Allocation

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***Abstract*—This paper presents a model for multi-period generation and transmission expansion planning (G&TEP) problem in the presence of uncertainties in the strategies of market participants. The effects of demand response (DR) and fixed series compensation (FSC) devices allocation are considered for peak shaving purposes and optimal utilization of transmission capacity, respectively. This may cutback the generating expansion capacity and transmission investment costs. The optimal expansion plan is achieved while the uncertainties in the generators' offers and demands' bids are considered in the market model. In this model, the DR preferences are integrated into the market clearing process of the independent system operator (ISO), which is applied to the load aggregators according to the locational marginal and market clearing prices. Shifting the demand, curtailing the peak, and onsite generation are considered as load reduction strategies in the demand response program. The ISO optimizes the decision submitted by generating companies and load aggregators in the presence of uncertainties. The proposed model is applied to the Garver, single-, two-, and four-area IEEE-RTS 24-bus systems to show the effectiveness of the multi-optional DR program and the FSC devices in the dynamic G&TEP problems.**

***Index Terms*—Dynamic generation-transmission expansion planning, demand response, peak load reduction, fixed series compensation, benders decomposition.**

## NOMENCLATURE

### A. Variables

| | |
|---|---|
| $p_{D_{nm}}^{tis}$ | Power consumed by block $m$ of consumer $n$ in demand scenario $i$, uncertainty condition $s$, at year $t$. |
| $p_{G_{hj}}^{tis}$ | Power generated by block $j$ of generator $h$ in demand scenario $i$, uncertainty scenario $s$, at year $t$. |
| $f_{pq,r}^{tis}, f_{pq}^{tis0}$ | Power flow in $r_{th}$/existing line of corridor p-q in demand scenario $i$, uncertainty scenario $s$, at year $t$. |
| $\theta_{p}^{tis}$ | Angel at bus $p$ in demand scenario $i$, uncertainty scenario $s$, at year $t$. |
| $P_{G_h}^{tis}$ | Power generated by generator $h$ in demand scenario $i$, uncertainty scenario $s$, at year $t$. |
| $P_{D_n}^{tis}$ | Power consumed by consumer $n$ in demand scenario $i$, uncertainty scenario $s$, at year $t$. |
| $\delta_{pq,a}^{tis0}$ | Variable used for linearizing the power flow in the existing lines, demand scenario $i$, uncertainty condition $s$ and year $t$. |
| $\delta_{pq,r,a}^{tis}$ | Variable used for linearizing the power flow in the prospective lines $r$, demand scenario $i$, uncertainty condition $s$ and year $t$. |
| $CLR_X^{tn}$ | The cost function of load reduction option $x$ provided by participant $n$ at year $t$. |
| $U_X^{tno}$ | Status of load reduction offer of option $x$ for participant $n$ at year $t$ (1, the contract is scheduled; 0, otherwise). |
| $LR_X^{tin}$ | Total load reduction of option $x$ for participant $n$ at year $t$ in demand scenario $i$. |

### B. Global variables

| | |
|---|---|
| $n_{pq,r}^{t}$ | Binary variable presenting the $r_{th}$ transmission lines installed in corridor $p$-$q$ at year $t$. |
| $y_{hj}^{t}$ | Construction decision of block $j$ unit of generator $h$ at year $t$ (1, to be constructed; 0, otherwise). |
| $u_{pq,r,a}^{t}$ | Binary variable presenting $a_{th}$ FSC installed in the prospective line $r$ at year $t$. |
| $u_{pq,a}^{t0}$ | Binary variable presenting $a_{th}$ FSC installed in the existing line between node $p$-$q$ at year $t$. |

### C. Parameters

| | |
|---|---|
| $\omega^{i}$ | Weighting factor of scenario $i$. |
| $\mu_{D_{nm}}^{ti}$ | Bid for block $m$ of demand $n$ in scenario $i$ at year $t$. |
| $\mu_{G_{hj}}^{ti}$ | Offer for block $j$ of generator $h$ in scenario $i$ at year $t$. |
| $c_{pq,r}$ | Transposed vector of the investment costs of new transmission lines. |
| $\alpha$ | Adjustment factor for costs of planning and operation. |
| $pr^{s}$ | Probability of scenario $s$. |

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$x_{pq}$ Reactance of corridor *p-q*.

$n_{pq}^{0}$ Transmission line in the initial topology.

$f_{pq}^{\max}$ Maximum power flow of the line in corridor *p-q*.

$p_{G_{hj}}^{\max}$ Size of block *j* of generator *h*.

$p_{G_{h}}^{\max}$ Maximum generation of unit *h*.

$U_e, U_p$ Binary parameters corresponding to the allocation of FSC in the existing and prospective lines.

$p_a$ Compensation level of FSC *a*.

$C_a$ Ratio of $a_{th}$ FSC's investment cost to investment cost of line (%).

$I$ Discount rate.

$IC_{X}^{On}$ Load reduction initiation cost of load reduction offer *O* of option *x* for participant *n* at time *t*.

$c_{X}^{tnO}, q_{X}^{tnO}$ Price and quantity of load reduction associated with the offer *O* of option *x* submitted by participant *n*.

*D. Sets*

$\gamma_c, \gamma_{c^1}$ Set of demand scenarios for $U_{LS}^{tno} = 0$ and $U_{LS}^{tno} \neq 0$, respectively.

$\gamma_S$ Set of all price uncertainty scenarios.

$\gamma_k$ Set of all the existing and prospective transmission lines.

$\gamma_r, \gamma_e$ Set of all the prospective/existing transmission lines in corridor *p-q*.

$\gamma_G, \gamma_G^Z$ Sets of all generating units, and generating units in node Z, respectively.

$\gamma_h$ Set of all blocks of generating unit *h*.

$\gamma_n$ Set of all blocks of demand *n*.

$\gamma_D, \gamma_D^Z$ Sets of all demands, and demands in node Z, respectively.

$\gamma_B$ Set of all buses.

$A$ Set of all candidate FSCs indexed by *a*.

$T$ Set of all years of the planning horizon.

## I. INTRODUCTION

GENERATION expansion planning (GEP) and transmission expansion planning (TEP) problems traditionally focus on minimizing the investment cost of new facilities to be installed in the power system [1]. The restructuring of the electric power industry brought new insight into the expansion planning models [2], [3]. In new models, some options such as market participants' strategies (generation companies (GENCOs), load aggregators, and transmission companies (TRANSCOs)), congestion, and security criteria have been enabled as the main components of the long-term planning problem [4], [5]. Power system constraints such as electricity demands, network flow limits, and reliability requirements are similarly applied to the TEP and GEP problems. However, according to the existing works in the literature, GEP can be driven by energy prices, but the same principles may not be used in TEP problems. On the other hand, handling the GEP and TEP problems simultaneously, namely G&TEP, by the ISO results in the most economical and reliable solutions while improving the social welfare (SW) and optimizing the energy utilization. Moreover, the existing uncertainties in power systems is an issue in finding an appropriate plan. The beneficial outcomes of simultaneous TEP and GEP, on the one hand, and the concerns related to the effects of uncertainties in finding an appropriate plan, on the other hand, have motivated the researchers from industry and academia to elaborate on the uncertainty-based G&TEP models.

In [6], a mixed integer linear programming (MILP) model for TEP considering uncertainties in demand was presented. In [7], a TEP model to cope with the uncertainties of demand and wind power was investigated. A stochastic coordination of a market-based model was presented in [8] to handle the long-term G&TEP problems. In this work, for the cost recovery purposes, a joint energy and transmission market model along with a capacity payment mechanism was assumed. In [9], a comprehensive reliability-based multi-area expansion model of generation and transmission components aiming at minimizing the total cost was proposed. In this model, the planning decisions were also satisfying the operating constraints. Nevertheless, the electricity demands, in either the deterministic or the scenario-based planning models, were considered to be constant. However, by developing smart technologies, the consumers are capable of participating in demand response (DR) programs. Controlling the demands besides the scheduling of generating units by the ISO brings more flexibility to the system, and consequently, the SW improves [10]. A proper DR program can provide an opportunity to alleviate transmission congestion by submitting the signals of electricity price changes to the end-users and consequently changing their electricity usage [11]. Therefore, DR could enhance the economic efficiency of the consumers by changing their consumption pattern from times of high-energy prices to other times to maximize their utility functions [12]. Moreover, the DR as a resource in wholesale electricity market operations can be considered as a business process model for DR participation in the electricity markets [13].

In [9], the load curtailment was used as a DR option to reduce the investment cost of new facilities. In [14], the DR program was used to reshape the system demands by integrating renewable sources under the wholesale energy market environment. In [15], a probabilistic TEP model incorporating DR was proposed to tackle the variability factors associated with grid-connected wind farms. In this paper, the incentive-based demand response (IBDR) program was used as a non-network solution instead of conventional expansion solutions. The objective of the model was to minimize the total investment, IBDR operating cost, and penalties corresponding to the wind curtailment. In [16], a probabilistic multi-objective

TEP incorporating DR programs was introduced. The DR provided a solution to control the power systems, ranging from short-term to long-term scheduling. While numerous studies have focused on the effects of load curtailment in the expansion planning problem, only a few studies considered other DR options such as load shifting and onsite generation, which are related to the operating problems. In order to fill the existing gap, proper models should be investigated for incorporating various DR resources simultaneously into the expansion planning problems and considering their economic values. Recently, clustering techniques as powerful tools for data classification have been used to generate representative scenarios for power system planning studies incorporating operating conditions [17]. In most of the previous works, the researchers considered only the peak load of the planning year rather than load profile and demand-side bidding. By taking into account the load profile, a different number of scenarios can be considered to describe the behavior of the demand. Each scenario represents different levels of the reference demand in a significant number of hours during one typical year of the network operation. Therefore, when peak loads occur in a scenario, the load is curtailed/shifted to an off-peak scenario. However, this may unexpectedly lead to a new peak either via the curtailment or the shifting strategies [18]. Considering load profile and demand bidding, locational marginal price (LMP) is different in various periods of the planning horizon. Typically, it is expected that by curtailing/shifting peak demands, the prices at peak hours considerably decrease. In most of the works in the literature, the planning issues are solved considering the energy market to expand and operate a power system aiming at maximizing the trade opportunities for all market participants. Due to the high value of investment cost and its importance for the market participants, considering the uncertainties in the future operating costs through the planning problem is essential, while most published works in this area only considered uncertainties in future demands, generation, and security criteria. On the other hand, to postpone the investment costs, optimal utilization of the existing transmission network, and even to improve the SW, considering fixed series compensators (FSCs) plays an important role [19].

In this paper, a dynamic G&TEP model incorporating the impact of FSC devices and DR options in a pool-based electricity market is considered. In this model the network topology, generator offers, and demand bids are taken into account. Moreover, the improvement of SW at the presence of DR in a G&TEP problem is investigated. Thus, ISOs accepts the DR bids in the wholesale markets on the basis that is comparable to other resources [20]. In the proposed model, it is assumed that GENCOs and demands submit their offers and bids to the ISO, and the ISO will solve the G&TEP problem considering uncertainties in the offers and bids of the market participants and then calculates the surpluses of the consumers as well as the suppliers. The investment and operating costs of a power system decrease the social benefit, therefore, the ISO by considering the FSCs and DR may defer the investment costs [9]. To solve this highly complicated problem, a benders decomposition technique is used. Consequently, comparing with the existing models in the literature, the main contributions of this paper are threefold.

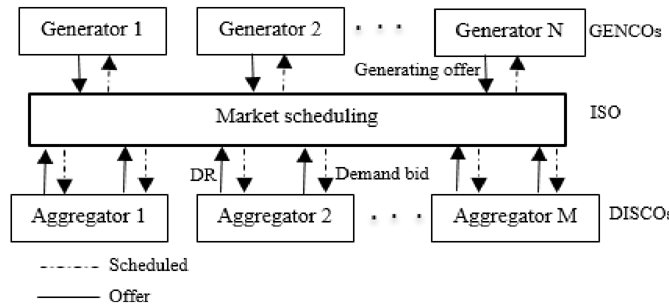


Fig. 1. Proposed market structure in planning process

i) considering the impacts of load shifting, load curtailment, and onsite generation in the operating constraints of the expansion planning model simultaneously;

ii) preventing of forming new unexpected peaks in other demand scenarios while shaving the main peaks in the specified scenarios. To do so, short-term operating actions such as electricity market are incorporated into long-term planning problems in a way that both the demand and supply sides participate in the market-clearing process. Therefore, shifting the load not only prevents forming new unexpected peaks in other demand scenarios but also results in deferring the investment cost, and consequently, increasing the total social welfare;

iii) considering uncertainties corresponding to the generators' offers, and demands' bids in the planning model.

The rest of this paper is organized as follows. Section II presents the model features. In section III, the mathematical model for dynamic G&TEP incorporating FSC and DR is described. Section IV contains the case studies and results. Section V provides the concluding remarks.

## II. Model Features

### A. Market Model

The proposed model is a perfectly-competitive energy market-based G&TEP model incorporating DR options where GENCOs and load aggregators make their offers and bids in an electricity pool. The structure of the hierarchical framework of the electricity market and DR bidding is shown in Fig. 1. It is assumed that no market power can be applied in this system and GENCOs/load aggregators submit their offers/bids according to their actual cost and utility functions. It is worth mentioning that in the proposed model there is no strategy in which the dominant players could have any effect on the market clearing process and the system outcome. Also, the aggregators submit the DR offers to the ISO according to their price-sensitive preferences. The ISO will expand the generating units and transmission system considering the uncertainties in offers and bids of the market participants [21].

The main objective of GENCOs and load aggregators is to maximize the profit through optimal planning, while ISO maximizes the SW and ensures proper operation of the system

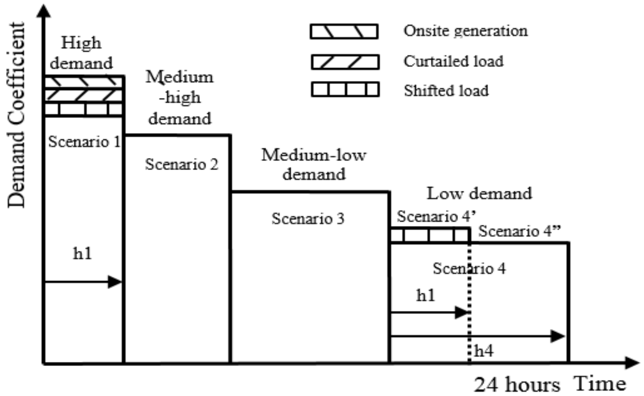


Fig. 2. Load Duration Curve

for each demand scenario [21], [22].

### B. Load Behavior and DR in the Planning Model

According to Fig. 2, the load duration curve is used with multiple demand scenarios to model demand behavior during the 24 hours of network operation, and it is extended to the planning horizon. Each demand scenario represents a significant number of hours with the same amount of demand. Considering Fig. 2 shows that in a scenario with high demand (i.e., scenario 1), the LMPs is higher than other scenarios [23]. Therefore, the load aggregators can submit the hourly DR offers regarding the consumers' load reduction options to increase their profits while decreasing the operating cost of generating units. These options include load curtailment (LC), load shifting (LS), and using onsite generation (OG), and energy storage (ES) devices [13]. The DR aggregators use various performance evaluation methodologies to determine proper load reduction options and quantities corresponding to DR preferences [24]. In this paper, the offer packages of DR aggregator includes the LS, LC, and OG.

*1) Load curtailment (LC)*

The load aggregators can use energy efficiency to reduce electricity demand in each scenario without shifting it to other scenarios. The load aggregator submits LC offer to the ISO which includes the quantity and price.

*2) Load shifting (LS)*

In this option, consumers shift their consumption to scenarios with low demand within a day. The offer of LS is submitted to the ISO by load aggregators as a quantity-price pair. The price in low demand hours may be lower. Therefore, it is profitable for the load aggregators to use LS offers.

*3) Onsite generation (OG)*

The OG is used to reduce the local load supplied by the grid. The load aggregator submits the hourly surplus of the OG as an offer to the ISO. This option may include a price-quantity pair and emission coefficients of the OG fleet.

The load aggregators can shift their consumption to the period with low demand (i.e., scenario 4). However, shifting the load can increase the demand at scenario 4 and results in a new peak. Considering load's price sensitivity, load aggregators change their electric usage according to price. Therefore, it does not cause a new peak in scenario 4. Peak demand (i.e., scenario 1) occurs in a few hours per day, compared to scenario 4.

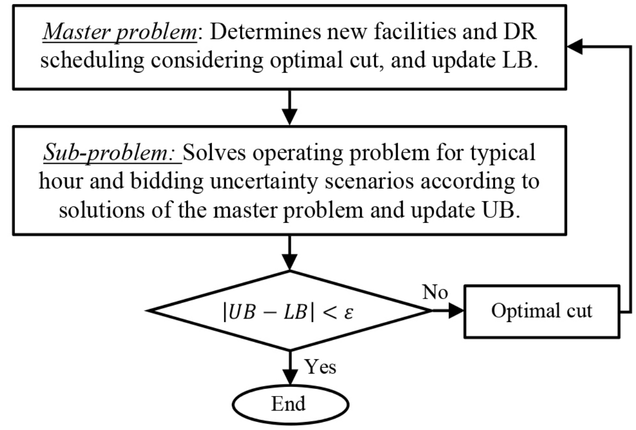


Fig. 3. The outline of decomposition algorithm

Therefore, according to Fig. 2, due to equality of energy, shifted from scenario 1 to scenario 4, load shifting changes scenario 4 into two scenarios (4' and 4" with $h1$ and ($h4$-$h1$) hours, respectively) with different levels of demand.

## III. Mathematical Modeling

This section presents multi-period G&TEP considering FSC allocation and DR formulation in the master problem and subproblem as follows.

### A. Master Problem

In the master problem, investment cost of new facilities and the cost of DR scheduling are minimized. The total investment cost includes the costs of new lines, generating units, FSCs, and DR programming. The ISO make the decisions considering the day-ahead energy market. The results in the master problem are submitted to the sub-problem for optimal operation. The proposed decomposition algorithm is outlined in Fig. 3 where the LB and UB stand for the lower and upper bounds, respectively. Therefore, we have.

$$
\begin{aligned}
\min IC \geq & \sum_{t=t_0+1}^{T}\sum_{\forall r\in\gamma_k} \frac{c_{pq,r}(n^{t}_{pq,r}-n^{t-1}_{pq,r})}{(1+I)^{t-t_0}} + \sum_{\forall r\in\gamma_k} c_{pq,r}(n^{t_0}_{pq,r}) \\
& + \sum_{t=t_0+1}^{T}\sum_{\forall j\in\gamma_g} \frac{c_{hj}(y^{t}_{hj}-y^{t-1}_{hj})}{(1+I)^{t-t_0}} + \sum_{\forall j\in\gamma_g} c_{hj}(y^{t_0}_{hj}) \\
& + C_a\Big(\sum_{t=t_0+1}^{T}\Big(\sum_{\forall (pq)\in\gamma_k} \frac{c_{pq}n^{0}_{pq}(u^{(t)0}_{pq,a}-u^{(t-1)0}_{pq,a})}{(1+I)^{t-t_0}} + \sum_{\forall r\in\gamma_k} \frac{c_{pq,r}(u^{t}_{pq,r,a}-u^{t-1}_{pq,r,a})}{(1+I)^{t-t_0}}\Big) \\
& + \sum_{\forall (pq)\in\gamma_k} c_{pq}n^{0}_{pq}(u^{(t_0)0}_{pq,a}) + \sum_{\forall r\in\gamma_k} c_{pq,r}(u^{t_0}_{pq,r,a})\Big) \\
& + \sum_{t=1}^{T}\sum_{\forall n\in\gamma_{DR}} \left( \frac{CLR^{tn}_{LR}}{(1+I)^{t-t_0}} + \frac{CLR^{tn}_{LS}}{(1+I)^{t-t_0}} + \frac{CLR^{tn}_{OG}}{(1+I)^{t-t_0}} \right)
\end{aligned}
\quad (1)
$$

The first two lines of the objective function (1) stand for the investment costs of new transmission lines and generating units; the third and fourth lines present the investment costs of the FSCs, and the last line presents the cost of the DR scheduling over the planning horizon.

In [19], a global investment cost has been considered for each FSC with a predefined compensation level $a$ ($C_a$) in US$/MW that contains the cost of capacitors. To calculate $C_a$, as a constant coefficient, the cost of FSC is divided by the cost of the line. Then, multiplying $C_a$ by line investment cost for the existing and candidate lines present the cost of FSC. The initial coordination between transmission and generation planning as well as DR and FSC scheduling is obtained by solving (1)-(18).

$$CLR_{LC}^{tn} = \sum_{O\in N_n^{LR}} \left( IC_{LC}^{On} U_{LC}^{tnO} + c_{LC}^{tnO} q_{LC}^{tnO} U_{LC}^{tnO} \right) \tag{2}$$

$$LR_{LC}^{tin} = \sum_{O\in N_n^{LC}} q_{LC}^{tnO} U_{LC}^{tnO}; \left(\forall i \in LRS\right) \tag{3}$$

$$CLR_{LS}^{tn} = \sum_{O\in N_n^{LS}} \left( IC_{LS}^{On} U_{LS}^{tnO} + c_{LS}^{tnO} q_{LS}^{tnO} U_{LS}^{tnO} \right) \tag{4}$$

$$LR_{LSa}^{tin} = \sum_{O\in N_n^{LS}} q_{LS}^{tnO} U_{LS}^{tnO}; \left(\forall i \in ALS\right) \tag{5}$$

$$LR_{LSr}^{tin} = \sum_{O\in N_n^{LS}} q_{LS}^{tnO} U_{LS}^{tnO}; \left(\forall i \in LRS\right) \tag{6}$$

$$CLR_{OG}^{tn} = \sum_{O\in N_n^{OG}} \left( IC_{OG}^{On} U_{OG}^{tnO} + c_{OG}^{tnO} q_{OG}^{tnO} \right) \tag{7}$$

$$U_{OG}^{tnO} p_{OG}^{\min,tnO} \le q_{OG}^{tnO} \le U_{OG}^{tnO} p_{OG}^{\max,tnO} \tag{8}$$

$$LR_{OG}^{tin} = \sum_{O\in N_n^{OG}} q_{OG}^{tnO}; \left(\forall i \in LRS\right) \tag{9}$$

$$n_{pq,r-1}^{t} - n_{pq,r}^{t} \ge 0 \;;\; \{\forall (pq) \in \gamma_k, \forall (t) \in T\} \tag{10}$$

$$n_{pq,r}^{t} - n_{pq,r}^{t-1} \ge 0 \;;\; \{\forall (pq) \in \gamma_k, \forall (t) \in T\} \tag{11}$$

$$y_{hj}^{t} - y_{hj}^{t-1} \ge 0 \;;\; \{\forall j \in \gamma_h, \forall (t) \in T\} \tag{12}$$

$$u_{pq,a}^{(t)0} - u_{pq,a}^{(t-1)0} \ge 0; \;\; \{\forall (pq) \in \gamma_k, \forall a \in A, \forall (t) \in T\} \tag{13}$$

$$u_{pq,r,a}^{t} - u_{pq,r,a}^{t-1} \ge 0; \;\; \{\forall (pq) \in \gamma_k, \forall a \in A, \forall (t) \in T\} \tag{14}$$

$$\sum_{a\in A} u_{pq,a}^{(t)0} \le U_e; \;\; \{\forall (pq) \in \gamma_k, \forall a \in A, \forall (t) \in T\} \tag{15}$$

$$\sum_{a\in A} u_{pq,r,a}^{t} \le U_p n_{pq,r}^{t}; \;\; \{\forall (pq) \in \gamma_k, \forall a \in A, \forall (t) \in T\} \tag{16}$$

$$\begin{gathered} \left| u_{pq,a}^{(t)0} - u_{pq,r,a}^{t} \right| \le 1 - n_{pq,r}^{t}; \\ \{\forall (pq) \in \gamma_k, r = 1, \forall a \in A, \forall (t) \in T\} \end{gathered} \tag{17}$$

$$\begin{gathered} \left| u_{pq,r-1,a}^{t} - u_{pq,r,a}^{t} \right| \le 1 - n_{pq,r}^{t}; \\ \{\forall (pq) \in \gamma_r, \forall a \in A, \forall (t) \in T\} \end{gathered} \tag{18}$$

Constraints (2), (4), and (7) refer to the cost functions of the LC, LS, and OG options, respectively. Aggregator $n$ submits $N_N^X$ offer of option $x$ (i.e., LS, LC, and OG) to the ISO, then the $O_{th}$ offer of option $x$ is characterized by the quantity $q_x^{TNO}$and the corresponding price $c_X^{tno}$ in the specified load scenario at year $t$. The total load reductions in LC, LS, and OG are presented in (3), (5), (6) and (9). In (5) and (6), $ALS$ and $LRS$ refer to the demand scenarios with lowest and heaviest loads, respectively. Constraint (8) presents the minimum/maximum dispatch of OG. Constraint (10) guarantees that the prospective lines are installed sequentially, while (11) and (12) guarantee that the line and unit installed in year $t$ remain operative during the planning horizon, respectively. Constraints (13) and (14) guarantee that an installed FSC remains operative during the whole planning horizon. Due to the lack of information for the line lengths in the system data, FSCs are installed in the lines with a reactance greater than 0.05 p.u. Therefore, in constraint (15) and (16), $U_e$ and $U_p$, as binary parameters, are set to 1 if the reactance of the corresponding line is greater than 0.05 p.u. Constraints (17) and (18) enforce the power flow balancing in parallel lines by installing the same FSCs in the existing and prospective lines. However, the master problem of decomposition algorithm, incorporating primal cutting planes, finds the optimal variables $n_{pq,r}^t$, $y_{hj}^t$, $u_{pq,a}^{(t)0}$, $u_{pq,r,a}^t$, $U_{LC}^{tno}$, $U_{LS}^{tno}$, and $U_{OG}^{tno}$. Afterwards, the sub-problem obtains the optimal variables $p_{D_n}^{tis}$, $p_{G_h}^{tis}$, $f_{pqr}^{tis}$, $\theta_p^{tis}$, $\delta_{pq,a}^{tis0}$, $\delta_{pq,a,r}^{tis}$ at the presence of uncertainty in the units' operating cost as well as the utility function of load aggregators.

*B. Optimal operation sub-problem*

In this problem, the demand scenario-weighted SW is maximized under different price uncertainty conditions over the planning horizon (19). The ISO clears the market considering units' offers and loads' bids defined in different uncertainty scenarios subject to transmission network and generation units specified in the master problem while the operating constraints are considered for all the uncertainty scenarios. In addition to the demand bids, the DR aggregators, on behalf of the responsive loads, also submit bids for providing load reduction options considered in the peak-demand scenarios. The proposed SW function is multiplied by the weighting factor of the demand scenario ($w^i$) as well as the occurrence probability of the uncertainty scenarios [11]. The ISO clears the typical day-ahead market expanded to one planning year and optimizes the DR offers for hourly load reductions.

In this formulation, the market is cleared for a typical hour of demand scenario $i$ in the scenario $s$. The total consumption of the demand $n$ (which is $p_{D_{nm}}^{tis}$ subtracted by $-LR_{LSa}^{tin}+LR_{LSr}^{tin}$ $+LR_{LC}^{tin}+LR_{OG}^{tin}$) is multiplied by $\mu_{D_{nm}}^{tis}$, therefore according to the demand bidding and cost of the load reduction offers and also the price in the corresponding bus, the aggregator's offers are scheduled by the ISO so that the total SW is maximized. Due to the binary variable $U_{LS}^{tno}$, determined in the master problem, the following cases are considered in the sub-problem.

*1)* $U_{LS}^{tno} = 0$: no load is shifted and sub-problem is solved normally, therefore in all constraints $i \in \gamma_c$.

*2)* $U_{LS}^{tno} \neq 0$: load is shifted to specified hours (off-peak load) by aggregators and demand scenario related to off-peak load is changed into two scenarios with different load level. For example, according to Fig. 2, scenario 4 changes to two scenarios (4' and 4") with different load level (five demand scenario are considered in sub-problem) and therefore in all constraints $i \in \gamma_{C^1}$.

$$\max \sum_{\forall t \in T} \sum_{\forall S \in \gamma_s} pr^s \sum_{\forall i} \left( w^i \left( \sum_{\forall n \in \gamma_D} \sum_{\forall m \in \gamma_n} \left( \frac{\left( \mu_{D_{nm}}^{tis} \left( p_{D_{nm}}^{tis} + LR_{LSa}^{tin} - LR_{LSr}^{tin} - LR_{LC}^{tin} - LR_{OG}^{tin} \right) \right)}{(1+I)^{t-t_0}} \right) - \sum_{\forall h \in \gamma_G} \sum_{\forall j \in \gamma_h} \frac{\mu_{G_{hj}}^{ts} p_{G_{hj}}^{tis}}{(1+I)^{t-t_0}} \right) \right) \tag{19}$$

$$\sum_{\forall p=z} f_{pqr}^{tis} + \sum_{\forall q=z} f_{pqr}^{tis} + \sum_{\forall(pq)\in\gamma_k} f_{pq}^{ts0} + \sum_{\forall h\in\gamma_G^Z} p_{G_h}^{tis} = \sum_{\forall n\in\gamma_G^Z} p_{D_n}^{tis} + LR_{LSa}^{tip} - LR_{LSr}^{tip} - LR_{LC}^{tip} - LR_{OG}^{tip}; \beta_Z^{tis} \{\forall z\in\gamma_B, \forall(t)\in T\} \tag{20}$$

$$x_{pq} f_{pq}^{tis0} - \sum_{a\in A} \delta_{pq,a}^{tis0} = n_{pq}^0 (\theta_p^{tis} - \theta_q^{tis}); \delta_{1pq}^{tis}, \{\forall(pq)\in\gamma_e, \forall s\in\gamma_s, \forall a\in A, \forall(t)\in T\} \tag{21}$$

$$\left| f_{pq}^{tis0} \right| \le n_{pq}^0 f_{pq}^{\max}; \varphi_{11pq}^{tis}, \varphi_{12pq}^{tis}, \forall s\in\gamma_s, \forall(pq)\in\gamma_e, \forall(t)\in T \tag{22}$$

$$\left| f_{pq}^{tis0} - \frac{\delta_{pq,a}^{tis0}}{x_{pq} p_a} \right| \le (n_{pq}^0)(1 - u_{pq,a}^{(t)0}) f_{pq}^{\max}; \omega_{11pq}^{tis}, \omega_{12pq}^{tis}, \{\forall s\in\gamma_s, \forall(pq)\in\gamma_e, \forall a\in A, \forall(t)\in T\} \tag{23}$$

$$\left| \frac{\delta_{pq,a}^{tis0}}{x_{pq} p_a} \right| \le (n_{pq}^0)(u_{pq,a}^{(t)0}) f_{pq}^{\max}; \tau_{11pq,a}^{tis}, \tau_{12pq,a}^{tis}, \{\forall s\in\gamma_s, \forall(pq)\in\gamma_e, \forall a\in A, \forall(t)\in T\} \tag{24}$$

$$\left| x_{pq} f_{pq,r}^{tis} - \sum_{a\in A} \delta_{pq,a,r}^{tis} - (\theta_p^{tis} - \theta_q^{tis}) \right| \le M(1 - n_{pq,r}^t); o_{11pq,a,r}^{tis}, o_{12pq,a,r}^{tis}, \{\forall s\in\gamma_s, \forall(pq)\in\gamma_r, \forall a\in A, \forall(t)\in T\} \tag{25}$$

$$\left| f_{pq,r}^{tis} \right| \le (n_{pq,r}^t) f_{pq}^{\max}; \zeta_{12pq,r}^{tis}, \zeta_{11pq,r}^{tis}, \forall s\in\gamma_s, \forall(pq)\in\gamma_r, \forall(t)\in T \tag{26}$$

$$\left| f_{pq,r}^{tis} - \frac{\delta_{pq,r,a}^{tis}}{x_{pq} p_a} \right| \le (1 - u_{pq,r,a}^t) f_{pq}^{\max}; \varsigma_{11pq,r,a}^{tis}, \varsigma_{12pq,r,a}^{tis}, \{\forall s\in\gamma_s, \forall(pq)\in\gamma_r, \forall a\in A, \forall(t)\in T\} \tag{27}$$

$$\left| \frac{\delta_{pq,r,a}^{tis}}{x_{pq} p_a} \right| \le (u_{pq,r,a}^t) f_{pq}^{\max}; \varepsilon_{11pq,r,a}^{tis}, \varepsilon_{12pq,r,a}^{tis}, \{\forall s\in\gamma_s, \forall(pq)\in\gamma_r, \forall a\in A, \forall(t)\in T\} \tag{28}$$

$$p_{G_h}^{tis} = \sum_{\forall j\in\gamma_h} p_{G_{hj}}^{tis}; \vartheta_{1h}^{tis}, \{\forall h\in\gamma_G, \forall s\in\gamma_s, \forall(t)\in T\} \tag{29}$$

$$0 \le p_{G_{hj}}^{tis} \le y_{hj}^t p_{G_{hj}}^{\max}; \vartheta_{2h}^{tis}, \{\forall j\in\gamma_h, \forall s\in\gamma_s, \forall(t)\in T\} \tag{30}$$

$$p_{D_n}^{tis} = \sum_{\forall m\in\gamma_n} p_{D_{nm}}^{tis}; \vartheta_{1n}^{tis}, \{\forall n\in\gamma_D, \forall s\in\gamma_s, \forall(t)\in T\} \tag{31}$$

$$0 \le p_{D_{nm}}^{tis} \le p_{D_{nm}}^{\max}; \vartheta_{2n}^{tis}, \{\forall m\in\gamma_n, \forall s\in\gamma_s, \forall(t)\in T\} \tag{32}$$

$$\left| \theta_p^{tis} - \theta_q^{tis} \right| \le \bar{\theta}; \vartheta_{31pq}^{tis}, \vartheta_{32pq}^{tis}, \{\forall(pq)\in\gamma_k, \forall s\in\gamma_s, \forall(t)\in T\} \tag{33}$$

$$\left| \theta_p^{tis} - \theta_q^{tis} \right| \le \bar{\theta} + M(1 - n_{pq,r}^t); \vartheta_{41pq}^{tis}, \vartheta_{42pq}^{tis}, \{\forall(pq)\in\gamma_k, \forall s\in\gamma_s, \forall(t)\in T\} \tag{34}$$

Constraint (20) stands for the power balance between the generation offers and responsive/non-responsive loads in all nodes. $\beta_Z^{tis}$ as the dual variable of the power balance constraint, is the nodal price at bus z in demand scenario $i$. Constraint (21) enforce the Kirchhoff's voltage law (KVL) in existing transmission lines, where FSC reduces line reactance as follows.

$$f_{pq}^{tis0} = \frac{n_{pq}^0 (\theta_p^{tis} - \theta_q^{tis})}{x_{pq}(1 - \sum_{a\in A} p_a u_{pq,a}^{(t)0})} \tag{35}$$

Equation (35) can be re-rewritten as follows, (36).

$$x_{pq} f_{pq}^{tis0} - x_{pq} f_{pq}^{tis0} \sum_{a\in A} p_a u_{pq,a}^{(t)0} = n_{pq}^0 (\theta_p^{tis} - \theta_q^{tis}) \tag{36}$$

This equation is nonlinear, and therefore, to linearize it, a new continuous variable, $\delta_{pq,a}^{tis0} = x_{pq} p_a f_{pq}^{tis0} u_{pq,a}^{(t)0}$ is used. The linear form of (35) can be expressed by (23)-(24). It is worth mentioning that the main reason of linearizing the nonlinear terms is that the existing commercial solvers guarantee finding the global solution of the MILP models, while, more often than not, even for a very well-defined solver-friendly mixed integer nonlinear nonconvex programming model, there is no guarantee for finding the global solution [25].

Constraints (25)-(28), similar to constraints (21)-(24) enforce the Kirchhoff's voltage law (KVL) to prospective lines [19]. M is a big value that ensures the constraint is relaxed when $n_{pq,r} = 0$, but when $n_{pq,r} = 1$, this value is not important and the KVL is satisfied for the corresponding line. Constraints (29) and (31) represent the total power generated/consumed by each unit/consumer, respectively. Constraints (30) and (32) determine the size of the blocks of the units and the demands in each scenario, respectively. Constraints (33), and (34) limit the voltage angle difference between nodes connected by the existing and prospective lines.

In this model, variables $\beta$, $\delta$, $\varphi$, $\omega$, $\tau$, $o$, $\xi$, $\varsigma$, $\varepsilon$, and $\vartheta$ are the dual variables related to constraints (20)-(34). The corresponding operating cut is presented as (37). Note that in the G&TEP models, if the objective was to maximize the profit of TRANSCOs, candidate line reinforcements could have been planned according to LMP differences, to compute the marginal value of the capacity of each line in the dispatch. In other words, in the models that the TRANSCOs are considered as a separate entity, their profits depend on the flowgate marginal price obtained from LMPs of both sides of the line in an independent level [8]. This may result in implementation difficulties, intractability, or even extra simplifying of the model to find the best trade-off between the model complexity and computational

$$IC \ge \sum_{\forall t\in T} \sum_{\forall i\in\gamma_i} \sum_{\forall s\in\gamma_s} \left( \begin{array}{l} n_{pq}^0 f_{pq}^{\max} (\varphi_{11pq}^{tis} + \varphi_{12pq}^{tis}) + (n_{pq}^0)(1 - u_{pq,a}^{t0}) f_{pq}^{\max} (\omega_{11pq}^{tis} + \omega_{12pq}^{tis}) + \\ \sum_{\forall r\in\gamma_k} \left( \begin{array}{l} \sum_{\forall a\in A} \left( \begin{array}{l} (n_{pq}^0)(u_{pq,a}^{(t)0}) f_{pq}^{\max} (\tau_{11pq,a}^{tis} + \tau_{12pq,a}^{tis}) + u_{pq,r,a}^t f_{pq}^{\max} (\varepsilon_{11pq,r,a}^{tis} + \varepsilon_{12pq,r,a}^{tis}) \\ + M(1 - n_{pq,r}^t)(o_{11pq,a,r}^{tis} + o_{12pq,a,r}^{tis}) + (1 - u_{pq,r,a}^t) f_{pq}^{\max} (\varsigma_{11pq,r,a}^{tis} + \varsigma_{12pq,r,a}^{tis}) \end{array} \right) \\ + (n_{pq,r}^t) f_{pq}^{\max} (\zeta_{11pq,r}^{tis} + \zeta_{12pq,r}^{tis}) \end{array} \right) \\ + p_{G_{hj}}^{\max} \vartheta_{1hj}^{tis} + y_{hj}^t p_{D_{nm}}^{\max} \vartheta_{2hj}^{tis} + \bar{\theta}(\vartheta_{31pq}^{tis} + \vartheta_{32pq}^{tis}) + (\bar{\theta} + M(1 - n_{pq,r}^t))(\vartheta_{41pq}^{tis} + \vartheta_{42pq}^{tis}) \end{array} \right) + \left( \begin{array}{c} \text{Right side of} \\ \text{inequality (1)} \end{array} \right) \tag{37}$$

TABLE I
GENERATION DATA FOR GARVER SYSTEM

| Bus | Units | Capacity (MW) | Operating Cost ($/MWh) | Investment Cost ($/kW/year) |
|---|---|---|---|---|
| 1 | AE1 | 150 | 10 | Existing unit |
| | A1 | 150 | 13 | 10 |
| | A2 | 150 | 16 | 7 |
| | A3 | 150 | 19 | 4 |
| 2 | B1 | 50 | 15 | 2 |
| | B2 | 50 | 17 | 1.5 |
| | B3 | 50 | 20 | 0.5 |
| 3 | CE1 | 120 | 20 | Existing unit |
| | CE2 | 120 | 22 | Existing unit |
| | CE3 | 120 | 25 | Existing unit |
| 6 | DE5 | 100 | 8 | Existing unit |
| | DE6 | 100 | 12 | Existing unit |
| | DE7 | 100 | 15 | Existing unit |
| | DE8 | 100 | 17 | Existing unit |
| | DE9 | 100 | 19 | Existing unit |
| | DE10 | 100 | 21 | Existing unit |

TABLE II
CHARACTERISTICS OF THE DIFFERENT SCENARIOS

| Scenario | Weight | Demand coefficient |
|---|---|---|
| $S_1$ | 0.4120 | 0.47 |
| $S_2$ | 0.3297 | 0.85 |
| $S_3$ | 0.1592 | 1.20 |
| $S_4$ | 0.0991 | 1.70 |

TABLE III
PRICES OF LOAD REDUCTION OFFERS (LS, LC AND OG)

| Offer | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|
| Price ($/MW) | 10 | 11 | 12 | 13 | 14 |

TABLE IV
RESULTS FOR GARVER SYSTEM (CASE 1)

| Year | $t_1$ | $t_2$ | $t_5$ | $t_7$ | $t_9$ |
|---|---|---|---|---|---|
| Line | $2n_{4-6}$ | $n_{1-5}$ | 0 | 0 | 0 |
| Units | 0 | A1,A2,A3<br>B1,B2,B3 | 0 | 0 | 0 |

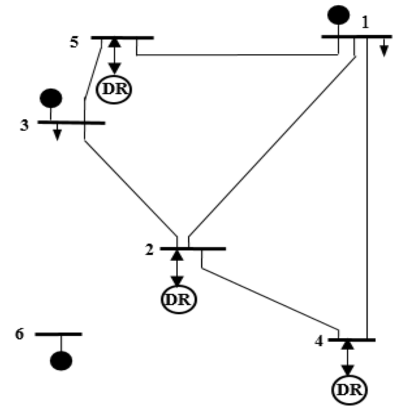


Fig. 4. Garver's System

TABLE V
RESULTS FOR GARVER SYSTEM (CASE 2)

| Year | $t_1$ | $t_2$ | $t_8$ | $t_9$ | $t_{10}$ |
|---|---|---|---|---|---|
| Line | $2n_{4-6}$ | 0 | $n_{1-5}$ | 0 | 0 |
| Units | 0 | A1, A2, A3, B1 | 0 | B2, B3 | 0 |
| FSC | $u^0_{1-2,3}$ | 0 | 0 | 0 | 0 |

TABLE VI
RESULTS FOR GARVER SYSTEM (CASE 3)

| Year | $t_1$ | $t_2$ | $t_8$ | $t_9$ | $t_{10}$ |
|---|---|---|---|---|---|
| Line | $2n_{4-6}$ | 0 | 0 | $n_{1-5}$ | 0 |
| Units | 0 | $A_2$, $B_1$ | 0 | $B_2$ | 0 |
| FSC | 0 | $u^0_{1-2,3}$ | 0 | 0 | 0 |

TABLE VII
ECONOMIC RESULTS FOR GARVER SYSTEM (CASE 1, 2 AND 3)

| | Annual Profits (M$) | | | Cost (M$) | | | | |
|---|---|---|---|---|---|---|---|---|
| | Units | Demands | Total SW | Units | Line | FSC | DR | Total |
| Case 1 | 110 | 317 | 377 | 16.9 | 33.9 | - | - | 50.8 |
| Case 2 | 110 | 322 | 372 | 16 | 33 | 9 | - | 58 |
| Case 3 | 117 | 331 | 381 | 16 | 33 | 9 | 6.4 | 64.4 |

tractability. However in the proposed model, the TRANSCOs is considered as a part of the ISO, so in the objective function there is no term related to the TRANSCOs profit, and consequently, the reinforcement of the network is done so the social welfare is maximized [23]. As an example, for the generating unit, since the objective of the proposed model is to maximize the producer's profits, therefore, the investments are made in a way that the generating units with lower production costs are installed, i.e., although the LMPs are not obtained from another level, due to optimality conditions of linear-based models, the generating unit that has the maximum marginal price difference with the LMPs of the other buses is selected.

## IV. CASE STUDIES AND RESULTS

The proposed model is tested on four systems such as Garver, IEEE-RTS 24-bus, two-area IEEE-RTS, and four-area IEEE-RTS. In this paper, three types of FSCs with different compensation percentages can be installed in a line as $p_1 = 20\%$ with $C_1 = 10\%$, $p_2 = 30\%$ with $C_2 = 15\%$ and $p_3 = 50\%$ with $C_3 = 20\%$ [19]. Moreover, due to the linearization of the demand utility function, the sum of DR offers for one option is equal to the size of one demand block. The proposed model is implemented in GAMS [26] and the commercial solver CPLEX is used to solve it [27]. In order to have a tractable problem, for this model in which the uncertainty is taken into account via a scenario-based approah, using an effective scenario reduction method is essential. In this paper, 10 approximated effective scenarios are used to model the uncertainty in the utility and cost functions of demand and generating units, respectively [8]. Moreover, the annual demand growth of 3.1% is considered [23]. It is noteworthy to mention that 1) all the generating units considered in the case studies are controllable, i.e., no intermittent generation exists, and 2) the candidate buses and lines are predefined to the planner; in cases that the candidate buses and lines are not predefined, the planner may perform an LMP-based analysis to find the most suitable set of candidates and then start the planning process [5].

### A. Garver's System

The Garver's system that is portrayed in Fig. 4 has 6 lines, 6 buses, three units, and five loads [19]. The planning horizon and the discount rate are 10 years and 10%, respectively. Each consumer submits five blocks of equal size but different prices [23]. The units' data is presented in Table I, while different scenarios are shown in Table II. In this paper, 20% of customers (equal to one demand block) are considered to be responsive to load curtailment, load shifting, and onsite generation offers. In Garver's system, load aggregators at buses 2, 4, and 5 are responsive to the DR offers with 5 blocks, equal in size but different in prices, Table III. Three different cases are investigated: case 1) without considering DR and FSC; case 2) considering FSC allocation, and case 3) considering FSC allocation and DR.

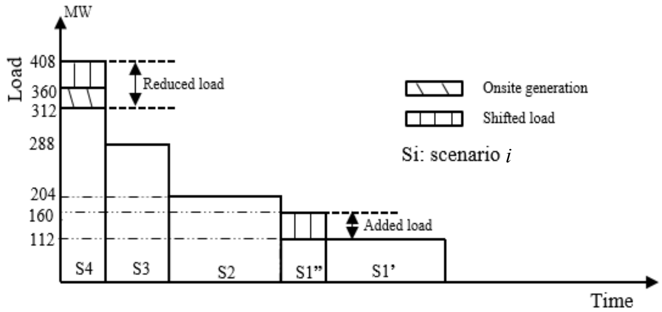

Fig. 5. Equivalent load duration curve of aggregator in Bus 2 at year 1, Case 3.

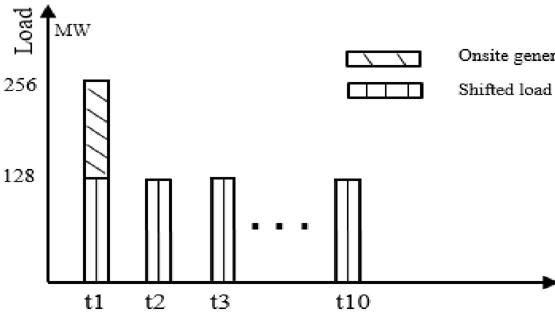

Fig. 6. The total load reduction in all responsive loads (Case 3).

TABLE VIII
AVERAGE LMP FOR GARVER SYSTEM (CASE 3)

| Scenario | $S_1$ | | $S_2$ | $S_3$ | $S_4$ |
|---|---|---|---|---|---|
| | $S_{1'}$ | $S_{1''}$ | | | |
| Price ($/MW) | 12 | 12.5 | 16.9 | 18.6 | 20 |

TABLE IX
GENERATION DATA FOR IEEE-RTS

| Bus | Units | MW offer | Cost | Units | | | |
|---|---|---|---|---|---|---|---|
| | | | | $u_1$ | $u_2$ | $u_3$ | $u_4$ |
| 1 | G1 | 250 | Operation | 15 | 18.8 | 22.5 | 26.3 |
| | | | Investment | EU | 5 | 3 | 2 |
| 2 | G2 | 250 | Operation | 13 | 16.3 | 19.5 | 22.8 |
| | | | Investment | EU | EU | 5 | 3 |
| 7 | G3 | 220 | Operation | 15 | 18.8 | 22.5 | 26.3 |
| | | | Investment | EU | 5 | 3 | 2 |
| 13 | G4 | 100 | Operation | 15 | 18.8 | 22.5 | 26.3 |
| | | | Investment | EU | 5 | 3 | 2 |
| 14 | G5 | 100 | Operation | 14 | 17.5 | 21 | 24.5 |
| | | | Investment | EU | 5 | 3 | 2 |
| 15 | G6 | 100 | Operation | 16 | 20 | 24 | 28 |
| | | | Investment | EU | 4 | 2 | 1.5 |
| 16 | G7 | 100 | Operation | 15 | 18.8 | 22.5 | 26.3 |
| | | | Investment | EU | EU | 6 | 4 |
| 18 | G8 | 100 | Operation | 13 | 16.3 | 19.5 | 22.8 |
| | | | Investment | EU | 5 | 3 | 2 |
| 21 | G9 | 100 | Operation | 14 | 17.5 | 21 | 24.5 |
| | | | Investment | EU | EU | EU | 5 |
| 22 | G10 | 300 | Operation | 15 | 18.8 | 22.5 | 26.3 |
| | | | Investment | EU | 2.5 | 1.5 | 0.5 |
| 23 | G11 | 200 | Operation | 15 | 18.8 | 22.5 | 26.3 |
| | | | Investment | EU | 5 | 3 | 2 |

Investment cost ($/kW/year) Operating cost ($/MWh) EU: existing unit

*1) Case 1: Without considering DR and FSC*

The planning results of this case are presented in Table IV. Results show that new lines connect the existing and new inexpensive units to the nodes with high demands. Economic results are presented in Table VII, which includes profits of generators, consumers, and the total SW. Note that, in all cases, the total SW is obtained by summing up the surpluses of the units, consumers, and planner while subtracting the investment costs of new facilities. As can be seen in Table VII, the present value of the investment costs of installing 6 generating units (three units in bus 1 and three units in bus 2 at $t_2$) and 3 transmission lines (two lines between bus 4 and 6 at $t_1$, and one line between bus 1 and 5 at $t_2$) are $16.9M and $33.9M, respectively. The average LMPs of this case for scenarios 1 to 4 are 12.1, 16.9, 18.4 and 21, respectively. Comparing scenarios 1 to 4 shows that the average LMP has been raised.

*2) Case 2: Considering FSC Allocation*

The results of planning for this case are presented in Table V. Table VII shows the economic results of the expansion plan along with the FSC for the market participants. The present value of the investment costs of installing 6 generating units (three units in bus 1 at $t_2$, and three units in bus 2, one at $t_2$ and the other two at $t_9$) and 3 transmission lines (two lines between bus 4 and 6 at $t_1$, and one line between bus 1 and 5 at $t_9$), and two FSCs (between bus 1 and 2, and bus 1 and 3 at $t_1$) are $16M, $33M, and $9M, respectively. Comparing the results of this case with case 1, in Table IV, shows that although the same as Case 1 the same numbers of lines and units have been installed, the installation time for some lines and units has been postponed, and this is mainly due to installing FSC in the existing lines. From Table VII, it can be observed that in the presence of FSC, the total SW has been decreased by $5M. In this case, the average LMPs for demand scenarios are 1 to 4 are 12, 16.9, 18.2 and 20.2, respectively. Comparing the average LMPs of this case with the previous case reveals that the average LMP is decreased in each demand scenario, as the FSC is installed.

*3) Case 3: Considering FSC Allocation and DR*

In this case, LS, LC, and OG are considered as the DR options. The results of planning are presented in Table VI. Comparing Table VI with Table V reveals that the installation times of line $n_{1-5}$ and FSC $u^0_{1-2,3}$ are postponed by one year. Table VII presents the economic results of the proposed model. According to this table, SW in case 3 is increased compared to the previous cases. The present value of the investment costs of installing three generating units (one unit in bus 1 at $t_2$, and two units in bus 2, one at $t_2$ and the other one at $t_9$), (two lines between bus 4 and 6 at $t_1$, and one line between bus 1 and 5 at $t_8$), and two FSCs (between bus 1 and 2, and bus 1 and 3 at $t_2$) are $16M, $33M, and $9M, respectively. Results show that unlike case 1 and case 2 in which 6 generating units have been installed, in this case only three units are required to be installed. Moreover, the total cost for the DR program is $6.4M. Therefore, considering the FSC and DR options, despite increasing investment cost, the total SW is increased by up to $4M. In addition, the profits of all participants are improved. Fig. 5 shows the load profile at bus 2 in the first year. According to this figure, OG and LS options are scheduled by the ISO for the demand aggregators, and due to the DR program, the equivalent load profile is smoother.

Fig. 6 demonstrates the total demand reduction in responsive loads. As can be seen from this figure, except for the first year,

TABLE X
RESULTS FOR IEEE-RTS (CASE 1, 2 AND 3)

| | | Annual profits (M$) | | | Cost (M$) | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Units | Demands | Total SW | Units | Line | FSC | DR | Total |
| Case 1 | | 148 | 306 | 440 | 32 | 104 | - | - | 136 |
| Case 2 | | 153 | 310 | 447 | 32 | 100 | 30.8 | - | 162.8 |
| Case 3 | DR (10%) | 160 | 323 | 450 | 30 | 144 | 51 | 117 | 342 |
| | DR (30%) | 154 | 344 | 456 | 30 | 231 | 23 | 127 | 411 |

TABLE XI
TOTAL LOAD REDUCTION FOR IEEE-RTS (CASE 3)

| Year | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| OG (MW) | 10% | 1172.4 | 1208.7 | 1245 | 1113.4 | 1084.6 | 901.2 | 194 | 0 | 0 | 0 |
| | 30% | 1758.6 | 1733.4 | 1731 | 1503.8 | 1413.0 | 144.6 | 33.6 | 0 | 0 | 0 |
| LS (MW) | 10% | 1172.4 | 1208.7 | 1245 | 1281.3 | 1317.6 | 1353.9 | 1390.1 | 1426.4 | 1462.7 | 1499.1 |
| | 30% | 1758.6 | 1813.1 | 1867.6 | 1922.1 | 1976.6 | 2031.1 | 2085.6 | 2140.1 | 2194.6 | 2248.7 |

TABLE XII
AVERAGE LMP FOR IEEE-RTS

| Scenario | | | $S_1$ | | $S_2$ | $S_3$ | $S_4$ |
|---|---|---|---|---|---|---|---|
| | | | $S_{1'}$ | $S_{1''}$ | | | |
| Price ($/MW) | Case 1 | | 19.1 | 19.1 | 26.5 | 33.4 | 37.3 |
| | Case 2 | | 19 | 19 | 25.8 | 33.2 | 37.1 |
| | Case 3 | DR 10% | 22.5 | 19.2 | 25.3 | 32.9 | 36.3 |
| | | DR 30% | 23.2 | 19.2 | 25.2 | 32.9 | 35.7 |

TABLE XIII
VSS FOR TWO CASE STUDIES

| | VSS | | |
|---|---|---|---|
| | Case 1 | Case 2 | Case 3 |
| Garver System | $527,000 | $513,890 | $513,855 |
| IEEE-RTS 24-bus System | $2,311,257 | $2,215,766 | $2,214,590 |

OG is not scheduled for the other years, however, due to the low cost of the LS, it has been scheduled for all years. While the ISO determines the optimal quantity of the demand to maximize the SW, the LC option cannot increase the profit of load aggregators and is not scheduled by the ISO. Table VIII presents the average LMP in 5 scenarios in case 3. By shifting the load to $S_1$, this scenario is divided into two scenarios $S_{1'}$ and $S_{1''}$. By comparing Tables VIII and the average LMPs obtained in the previous case, a decrease in the LMP at scenario $S_4$ is observed. Moreover, due to the load shifted to scenario $S_{1'}$, the LMP in scenario $S_{1''}$ is more than the LMP in scenario $S_{1'}$.

The output of the expensive unit, located at bus 3, in cases 2 and 3, are 200 MW and 156.8 MW, respectively, and shows that the DR can effectively decrease the generating cost of the expensive units. However, compared to case 1, the total SWs by considering FSC in case 2 is decreased by 1.4%, while considering FSC and DR in case 3 resulted in a 1% increase. This shows the effectiveness of joint consideration of FSC and DR in the planning problem.

*B. IEEE-RTS 24-bus System*

The market structure of the IEEE-RTS 24-bus system consists of 11 units and 17 loads [23], [28]. As can be seen in Table IX, for this system, some power plants have decided to construct new units. There is an aggregator at each load bus, and the data of the DR offer and the load demand scenarios are the same as the previous case study. Similar to the previous case study, this system is investigated under three different conditions: G&TEP, G&TEP considering FSC, and G&TEP considering DR and FSC. In this case study, the DR is considered with two participation levels of 10% and 30%.

*1) Case 1: Without considering DR and FSC*

New facilities to be installed are as follows.

- Year 1: lines $3n_{1-5}$ and generating units $G_1(u_3,u_4)$, $G_2(u_3)$, $G_3(u_3,u_4)$ , $G_{10}(u_2,u_3,u_4)$, $G_{11}(u_4)$.
- Year2: line $n_{1-5}$, and units $G_1(u_2)$, $G_2(u_3,u_4), G_3(u_2)$, $G_4(u_2,u_3,u_4)$, $G_7(u_3,u_4)$, $G_3(u_2)$, $G_9(u_4)$.

where $G_h(u_j)$ refers to unit $j$ of generator $h$.

*2) Case 2: Considering FSC Allocation*

New facilities to be installed in this case are as follows.

- Year 1: lines $2n_{1-5}$, units are similar to case 1 at first year 1, and FSCs in existing lines are: $u_{1-3,3}^0$, $u_{2-6,3}^0$.
- Year 2: lines $2n_{1-5}$, units are similar to case 1 at year 2 and FSC in existing line is $u_{12-23,1}^0$.

*3) Case 3: Considering FSC Allocation and DR*

In this case, the capacities of the three DR options are the same. New units, lines, and FSCs obtained for 10% of DR at each load bus are as follows.

- Year 1: lines $4n_{1-5}$, generating units $G_1(u_3,u_4)$, $G_3(u_3,u_4)$, $G_{10}(u_2,u_3,u_4)$ , and FSCs $u_{1-3,3}^0$, $u_{2-6,3}^0$.
- Year 2: line $n_{2-4}$, units $G_1(u_2)$, $G_2(u_3,u_4)$, $G_3(u_2)$, $G_4(u_2,u_3,u_4)$, $G_7(u_3,u_4)$, $G_8(u_2,u_3,u_4)$, $G_9(u_4)$, $G_{11}(u_2,u_3)$, and FSCs $u_{12-23,3}^0$, $u_{13-23,1}^0$, year 5: line $n_{2-4}$, and year 6: FSC $u_{4-9,3}^0$.

Considering 30% of the DR at each load bus, the following results are obtained.

- Year 1: lines $2n_{1-5}$, $n_{16-17}$, $n_{17-22}$, units $G_1(u_2,u_3)$, $G_3(u_4)$, $G_{10}(u_2,u_3,u_4)$, $G_{11}(u_3,u_4)$ and FSC $u_{2-6,3}^0$.
- Year 2: lines $2n_{1-5}, n_{2-4}$, units $G_1(u_4)$, $G_2(u_3,u_4)$, $G_3(u_2,u_3)$, $G_4(u_2,u_3,u_4)$, $G_7(u_3,u_4)$, $G_8(u_2,u_3,u_4)$, and FSC $u_{2-6,3}^0$, and year 3; FSC $u_{5-10,3}^0$.

The economic results for all cases are presented in Table X. Comparing the investment costs of cases 1 and 2 reveals that despite increasing the cost, installing the FSC increases the total annual SW up to $7M. Considering the DR in load aggregators along with FSC allocation, the total SW is increased. Moreover, in case 3 the total SW is increased due to the higher DR level utilization. However, the total SWs, compared to case 1, considering new strategies (DR and FSC) are increased 1.5% in case 2 as well as, in case 3, increased 2.2% and 3.6% for DR participation of 10% and 30%, respectively. Table XI shows the total load reduction (OG and LS) for two DR levels in all planning horizon. Since the objective function of the subproblem is to determine the consumption so that the optimal SW is obtained, therefore, a load reduction does not necessarily increase the SW such that the LC option is not considered in case 3. Table XII presents the average LMP for all cases. As can be seen, installing the FSC and utilizing the DR decreases the average price in scenario S4 (scenario with a heavy load). In case 3, due to shifting the load from $S_4$ to $S_1$, the average LMP is increased.

To show the advantage of using a stochastic programming approach over a deterministic one, a well-known metric, the value of the stochastic solution (VSS), is utilized [29]. Table XIII shows the VSSs for the first two cases of the test systems. This metric, for all the case studies, confirms the advantage of using the proposed stochastic model. Moreover, it can be seen that the VSSs decrease from case 1 to case 3 that is mainly due to the degree of freedom that the FSCs and DRs add to the power system. This results in more flexibility, and consequently, better decisions are made for the scenario-based model.

*C. Two- and Four-Area IEEE-RTS System*

In order to show the implementability of the proposed approach on large scale systems, two systems such as two- and four-area IEEE-RTS systems are studied. The topology of two-area RTS system, shown in Fig. 7 (a) is derived from [28]. According to [28], the topology of the IEEE-RTS 24-bus system as a single area is labeled by "Area A". The two-area system is developed by merging two single areas "Area A" and "Area B" by the following three interconnections.

- 51 mile 230 kV line connecting bus 23 and bus 41.
- 52 mile 230 kV line connecting bus 13 and bus 39.
- 42 mile 230 kV line connecting bus 7 and bus 27.

The four-area system is formed by adding two more single areas ("Area C" and "Area D") to the two-area system by the same three interconnections shown in Fig. 7 (b). All the generating units for all areas are similar and labeled for areas A, B, C and D as $G_1$-$G_{11}$, $G_{12}$-$G_{22}$, $G_{23}$-$G_{33}$, and $G_{34}$-$G_{44}$, respectively. The market structure for all areas is the same as the previous case study. These systems are investigated under three different conditions such as G&TEP, G&TEP considering FSC, and G&TEP considering DR and FSC. The DR is considered with the participation level of 30%.

The results for the two-area IEEE-RTS system are as follows.

*1) Case 1: Without considering DR and FSC*

New facilities to be installed are as follows.

- Year 1: lines $3n_{1-5}, 3n_{25-29}$, and $n_{26-28}$; and the generating units $G_1(u_2,u_3,u_4)$, $G_2(u_3,u_4)$, $G_3(u_2,u_3,u_4)$, $G_4(u_2,u_3,u_4)$, $G_5(u_2,u_3,u_4)$, $G_6(u_2,u_3,u_4)$, $G_7(u_3,u_4)$, $G_8(u_2,u_3,u_4)$, $G_{10}(u_2,u_3,u_4)$, $G_{11}(u_2,u_3,u_4)$, $G_{12}(u_2,u_3,u_4)$, $G_{13}(u_3,u_4)$, $G_{14}(u_2,u_3,u_4)$, $G_{15}(u_2,u_3,u_4)$, $G_{16}(u_2,u_3,u_4)$, $G_{17}(u_2,u_3,u_4)$, $G_{18}(u_3,u_4)$, $G_{19}(u_2,u_3,u_4)$, $G_{20}(u_4)$, $G_{21}(u_2,u_3)$, and $G_{22}(u_2,u_3,u_4)$.
- Year 2: lines $n_{2-4}$, and $n_{17-22}$.

*2) Case 2: Considering FSC Allocation*

New facilities to be installed in this case are as follows.

- Year 1: lines $3n_{1-5}$, $n_{2-4}$, $3n_{25-29}, n_{26-28}$, and $n_{41-46}$; the generating units are similar to case 1 at the first year without considering $G_{20}(u_4)$; and FSCs in the existing lines $u^0_{2-6,3}$.
- Year 10: FSCs in the existing lines $u^0_{23-41,3}$, and $u^0_{8-10,2}$.

*3) Case 3: Considering FSC Allocation and DR*

- Year 1: lines $2n_{1-5}$, $n_{16-17}$, and $n_{17-22}$; the units are similar to case 1 at the first year; and FSCs in the existing lines $u^0_{2-6,3}$.
- Year 10: line $n_{41-46}$; and FSCs in the existing lines $u^0_{25-27,2}$.

The results for four-area IEEE-RTS system are as follows.

*1) Case 1: Without considering DR and FSC*

New facilities to be installed are as follows.

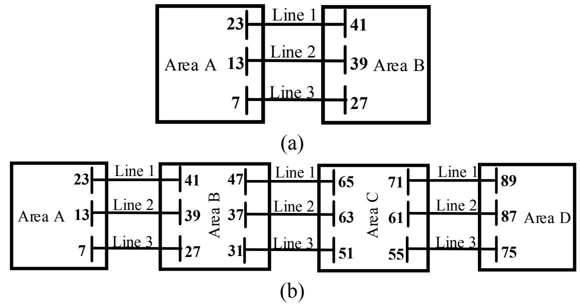


Fig. 7. IEEE-RTS systems— (a): two-area, and (b): four-area

TABLE XIV
RESULTS FOR TWO-AREA IEEE-RTS (CASE 1, 2 AND 3)

| | Annual profits (M$) | | | Cost (M$) | | | | |
|---|---|---|---|---|---|---|---|---|
| | Units | Demands | Total SW | Units | Line | FSC | DR | Total |
| Case 1 | 6178 | 7163 | 13104 | 1332 | 290 | - | - | 1622 |
| Case 2 | 6312 | 7157 | 13128 | 1322 | 292 | 9.8 | - | 1623.8 |
| Case 3 | 6502 | 7403 | 13635 | 1324 | 254 | 8.3 | 284 | 1870.3 |

TABLE XV
RESULTS FOR FOUR-AREA IEEE-RTS (CASE 1, 2 AND 3)

| | Annual profits (M$) | | | Cost (M$) | | | | |
|---|---|---|---|---|---|---|---|---|
| | Units | Demands | Total SW | Units | Line | FSC | DR | Total |
| Case 1 | 12415 | 14272 | 26221 | 2685 | 435 | - | - | 3120 |
| Case 2 | 12255 | 14189 | 26301 | 2711 | 437 | 11 | - | 3159 |
| Case 3 | 12222 | 14843 | 27199 | 2690 | 430 | 3 | 569 | 3692 |

TABLE XVI
TOTAL LOAD REDUCTION FOR TWO- AND FOUR-AREA IEEE-RTS (CASE 3)

| Year | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| OG | 2A | 1190 | 1190 | 1190 | 1190 | 1190 | 1190 | 1190 | 1080 | 950 | 932 |
| (MW) | 4A | 2344 | 2344 | 2344 | 2344 | 2344 | 2344 | 2344 | 2344 | 2344 | 2200 |
| LS | 2A | 1172 | 1172 | 1172 | 1172 | 1172 | 1172 | 1172 | 1172 | 1172 | 1172 |
| (MW) | 4A | 2344 | 2344 | 2344 | 2344 | 2344 | 2344 | 2344 | 2344 | 2305 | 2305 |

2A: two-area RTS system; 4A: four-area RTS system

TABLE XVII
AVERAGE LMP FOR TWO-AREA IEEE-RTS

| Scenario | | $S_1$ | | $S_2$ | $S_3$ | $S_4$ |
|---|---|---|---|---|---|---|
| | | $S_{1'}$ | $S_{1''}$ | | | |
| Price ($/MW) | Case 1 | 29.43 | 29.43 | 42.9 | 53 | 55 |
| | Case 2 | 29.53 | 29.53 | 42.6 | 54.3 | 56.1 |
| | Case 3 | 31.9 | 29.6 | 42.5 | 55.2 | 55 |

TABLE XVIII
AVERAGE LMP FOR IEEE FOUR-AREA IEEE-RTS

| Scenario | | $S_1$ | | $S_2$ | $S_3$ | $S_4$ |
|---|---|---|---|---|---|---|
| | | $S_{1'}$ | $S_{1''}$ | | | |
| Price ($/MW) | Case 1 | 29.5 | 29.5 | 42.5 | 55 | 56.9 |
| | Case 2 | 29.4 | 29.4 | 42.6 | 54.6 | 56 |
| | Case 3 | 31.8 | 29.4 | 42.7 | 54.9 | 54.8 |

- Year 1: lines $3n_{1-5}, 3n_{25-29}, 3n_{49-53}, n_{50-52}$, and $3n_{73-77}$; the generating units $G_1(u_2,u_3,u_4)$, $G_2(u_3,u_4)$, $G_3(u_2,u_3,u_4)$, $G_4(u_2,u_3,u_4)$, $G_5(u_2,u_3,u_4)$, $G_6(u_2,u_3,u_4)$, $G_7(u_3,u_4)$, $G_8(u_2,u_3,u_4)$, $G_{10}(u_2,u_3,u_4)$, $G_{11}(u_2,u_3,u_4)$, $G_{12}(u_2,u_3,u_4)$, $G_{13}(u_3,u_4)$, $G_{14}(u_2,u_3,u_4)$, $G_{15}(u_2,u_3,u_4)$, $G_{16}(u_2,u_3,u_4)$, $G_{17}(u_2,u_3,u_4)$, $G_{18}(u_3,u_4)$, $G_{19}(u_2,u_3,u_4)$, $G_{20}(u_4)$, $G_{21}(u_2,u_3)$, $G_{22}(u_2,u_3,u_4)$, $G_{23}(u_2,u_3,u_4)$, $G_{24}(u_3,u_4)$, $G_{25}(u_2,u_3,u_4)$, $G_{26}(u_2,u_3,u_4)$, $G_{27}(u_2,u_3,u_4)$, $G_{28}(u_2,u_3,u_4)$, $G_{29}(u_3,u_4)$, $G_{30}(u_2,u_3,u_4)$, $G_{31}(u_4)$, $G_{32}(u_2,u_3)$, $G_{33}(u_2,u_3,u_4)$ ), $G_{34}(u_2,u_3,u_4)$, $G_{35}(u_3,u_4)$, $G_{36}(u_2,u_3,u_4)$, $G_{37}(u_2,u_3,u_4)$, $G_{38}(u_2,u_3,u_4)$, $G_{39}(u_2,u_3,u_4)$, , $G_{40}(u_3,u_4)$, $G_{41}(u_2,u_3,u_4)$, $G_{42}(u_4)$, $G_{43}(u_2,u_3)$, and $G_{44}(u_2,u_3,u_4)$.
- Year 7: line $n_{89.9-4}$
- Year 8: lines $n_{66-70}, 2n_{74-76}$
- Year 9: line $n_{26-28}$,
- Year 10: lines $n_{44-47}, 2n_{2-4}$.

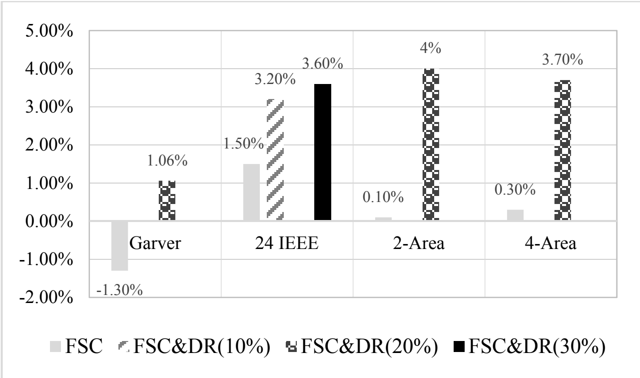


Fig. 8. Percentage of SW change per strategy (strategy 1: FSC and strategy 2: FSC&DR)

*2) Case 2: Considering FSC Allocation*

New facilities to be installed in this case are as follows.

- Year 1: lines $3n_{1-5}$, $n_{2-4}$, $3n_{25-29}$, $n_{26-28}$, , $3n_{49-53}$, $n_{50-52}$, $3n_{73-77}$, and $n_{74-76}$; units are similar to case 1 at the first year without considering $G_{20}(u_4)$; and FSCs in the existing lines $u^0_{26-30,1}$, $u^0_{50-54,1}$, and $u^0_{74-78,1}$
- Year 9: FSCs in the existing lines $u^0_{2-6,2}$,
- Year 15: FSCs in the existing lines $u^0_{8-10,3}$ and $u^0_{32-34,3}$

*3) Case 3: Considering FSC Allocation and DR*

- Year 1: lines $3n_{1-5}$, $n_{2-4}$, $3n_{25-29}$, $3n_{49-53}$, $n_{50-52}$, $3n_{73-77}$; units are similar to case 1 at the first year; FSC in the existing lines $u^0_{2-6,3}$.
- Year 9: line $n_{89-94}$,
- Year 10: line $n_{74-76}$.

Economic results for two systems are presented in Tables XIV and XV. Results show that the total SWs, compared to case 1, are increased for both systems considering new strategies (DR and FSC). For cases 2 and 3 of the two-area IEEE-RTS system, the increases are about 0.18% and 4%, respectively, and for cases 2 and 3 of the four-area IEEE-RTS system, the increases are about 0.3% and 3.7%, respectively. Moreover, the investment costs for two-area IEEE-RTS system in cases 2 and 3 have been increased by 0.11% and 15.3%, respectively, while the increases for cases 2 and 3 of the four-area IEEE-RTS system are 1.2% and 18% in, respectively. Table XVI shows the total load reduction (OG and LS) for two DR levels over the planning horizon. The average LMPs for two systems are brought in Tables XVII and XVIII. As can be seen from these tables, some consumers can shift their consumption to the first scenario with a lower price that is more financially beneficial to them. It is worth mentioning that the proposed model requires about 2 and 3.5 hours to solve the two- and four-area IEEE-RTS systems, respectively, that proves the computational efficiency.

Fig. 8 shows the percentage of SW changes of strategy 1, with FSC, and strategy 2, with FSC and DR, relative to baseline. It can be seen that under strategy 2, with FSC and DR, the increase of SW is greater than Strategy 1 in all case studies. It is shown that DR with shifting the load to an off-peak scenario, can reduce the investment cost in the generation side and improve the whole welfare.

## V. Conclusion

In this paper, a dynamic G&TEP model considering the FSC allocation and DR has been proposed in the presence of uncertainty in offering prices. In this model, the aggregators in addition to demand bids propose the LS, OG and LC options in the ISO's market clearing problem. A benders decomposition approach has been used to handle the proposed model. Commonly-used test systems such as Garver's and the IEEE-RTS 24-bus systems have been used to verify the model and test its potential. Results show that considering multi-optional DR in G&TEP problem can improve the SW, while installing the FSC not only improves the SW but also enhances the operational performance of the transmission network and redistribute active power more efficiently. Moreover, taking into account the customer DR and FSC allocation in the planning model provides more flexible options to the ISOs for scheduling the available energy resources and new facilities in the planning process.

On the other hand, more often than not the planning models, when applied to a very large-scale power system, due to a huge number of decision variables, become computationally intractable. However, the proposed model, compared to the existing planning model, by considering the aforementioned DR options jointly with FSC devices, provides more degree of freedom that improves its applicability in real-world power systems. To this end, the proposed model has been tested on two- and four-area IEEE-RTS systems. Results prove the effectiveness and usefulness of the model in handling larger scale power systems within a high computational efficiency.

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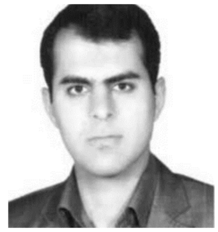

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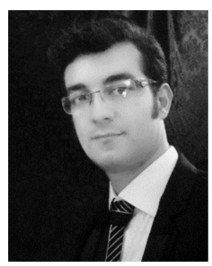

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