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A bi-level integrated generation-transmission planning model incorporating the impacts of demand response by operation simulation

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ABSTRACT

If all the resources in power supply side, transmission part, and power demand side are considered together, the optimal expansion scheme from the perspective of the whole system can be achieved. In this paper, generation expansion planning and transmission expansion planning are combined into one model. Moreover, the effects of demand response in reducing peak load are taken into account in the planning model, which can cut back the generation expansion capacity and transmission expansion capacity. Existing approaches to considering demand response for planning tend to overestimate the impacts of demand response on peak load reduction. These approaches usually focus on power reduction at the moment of peak load without considering the situations in which load demand at another moment may unexpectedly become the new peak load due to demand response. These situations are analyzed in this paper. Accordingly, a novel approach to incorporating demand response in a planning model is proposed. A modified unit commitment model with demand response is utilized. The planning model is thereby a bi-level model with interactions between generation-transmission expansion planning and operation simulation to reflect the actual effects of demand response and find the reasonably optimal planning result.

1. Introduction

Power system planning conventionally consists of generation expansion planning (GEP) and transmission expansion planning (TEP) [1]. GEP deals with the expansion of generation resources to serve growing electric power demand, while TEP concerns the expansion of the grid network to meet the requirements of power transmission [2–4]. These two planning issues tend to be executed separately, since they have not only different decision variables, objective and constraints but also different stakeholders. However, as the problem of renewable (wind and solar, etc.) generation curtailment becomes increasingly serious, it is currently believed that GEP and TEP should be conducted together to optimize energy utilization and improve investment efficiency, even though some power systems have been deregulated [5,6]. Some scholars have made contributions to this field in recent years. Seddighi and Ahmadi-Javid [1] present a multistage programming model to balance sustainable power generation expansion planning and transmission expansion planning. Aghaei et al. [7] introduce a probabilistic model for generation and transmission expansion planning considering reliability criteria. Moghaddam et al. [8] put forward a coordinated planning model based on interactive and iterative processes between GEP and TEP. Pozo et al. [9] describe a three-level equilibrium model for the expansion of generation and transmission. Rouhani et al. [10] propose a composite generation and transmission expansion model in which the objectives and constraints of GEP and TEP are integrated.

In addition to generation and transmission, load demand is another important part of power systems. Traditionally, the demand side is not considered in planning issues, because the supply-demand balance in power systems is achieved by adjusting supply to meet demand. However, with the development of smart grid, units in the supply side as well as resources in the demand side can be scheduled by the system operator [11]. The concept of Demand Response (DR) appears as "changes in electric usage by end-use customers from their normal consumption patterns

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Nomenclature

Indices

i	candidate generator
j	candidate transmission line
k	demand response source
l	existing generator
n	node
t	year
u	unit
v	hour

Sets

Ω_d	set of demand response sources
Ω_{dlc}	set of demand response sources (load curtailment type)
Ω_g	set of candidate generation units
Ω_G	set of existing generation units
Ω_l	set of candidate transmission lines
Ω_T	set of planning years
Ω_{vg}	set of candidate variable energy generation units
Ω_{vG}	set of existing variable energy generation units

Parameters

C_i/C_l	capacity of the ith candidate generator/lth existing generator (MW)
$Cd_{k,\max}$	potential capacity the kth demand response source (MW)
Clc	cost of load curtailment (yuan)
Cls	cost of load shifting (yuan)
$Ed_{\max}$	upper limit on the amount of electricity output by demand response (MW h)
e_i/e_l	carbon dioxide emission factor of the ith candidate generator/lth existing generator (kg/MW h)
Ef_t	electricity demand forecast in the tth year (MW h)
FC_u	fuel cost of the uth generation unit (yuan)
G_i	construction cost per unit of capacity of the ith candidate generator (yuan/MW)
H_{it}/H_{lt}	utilization hour of the ith candidate generator/lth existing generator in the tth year (h)
H_{kt}	utilization hour of the kth demand response source in the tth year (h)
L_v	load demand in the vth hour (MW)
L_v^0	original load demand in the vth hour (MW)
$Lc_{n,\max}$	upper limit on daily load curtailment at the nth node (MW)
$Lc_{n,v,\max}$	upper limit on load curtailment at the nth node in the vth hour (MW)
$Ls_{n,\max}$	upper limit on daily load shifting at the nth node (MW)
$Ls_{n,v,\max}$	upper limit on load shifting at the nth node in the vth hour (MW)
MU_u/MD_u	minimum continuous on/off time of the uth generation unit
N	total number of nodes in the system
$Nl_{j,\max}$	maximum number of circuits in the jth candidate line
O_i/O_l	operating cost (including fuel cost) per unit of electricity generation of the ith candidate generator/lth existing generator (yuan/MW h)
Od_k	response cost of the kth demand response source (yuan/MW h)
$P_{G\max}$	maximum output of the generator (MW)
$P_{G\min}$	minimum output of the generator (MW)
P_v	price of electric power in the vth hour (yuan)
P_v^0	original price of electric power in the vth hour (yuan)
Pr_C	carbon emissions trading price (yuan/kg)
Pf_t	peak load forecast in the tth year (MW)
R_i/R_l	peak load regulation capacity ratio of the ith candidate generator/the lth existing generator (%)
Rur_u/Rdr_u	ramp-up/ramp-down rate bound of the uth unit (MW/h)
SUC_u/SDC_u	start-up/shut-down cost of the uth unit (yuan)
T_j	construction cost of the jth candidate transmission line (yuan)
U	number of generation units
Uce	upper limit of carbon emissions of the power system (kg)
$Upmax_u/Upmin_u$	maximum and minimum power generation bounds of the uth unit (MW)
$X_{\max}$	maximum number of new generation units in the expansion scheme
$Y_{\max}$	maximum number of new transmission lines in the expansion scheme
β	peak-valley difference rate of the load demand in the system
η	reserve factor
$\theta_{n,\max}/\theta_{n,\min}$	upper and lower limit on the phase angle of the nth node

Variables

Cd_k	capacity of the kth demand response source (MW)
$Lc_{n,v}$	load curtailment at the nth node in the vth hour (MW)
$Ls_{n,v}$	load shifting at the nth node in the vth hour (MW)
$I_{u,v}$	operation status of the uth unit in the vth hour {1, on; 0, off}
Pd_n	power demand of the nth node (MW)
Pg_i	output of the ith generator (MW)
Pg_n	power injection of the nth node (MW)
$Pmax_{n'n}$	upper limit on power flow transmission in the branch between the n'th node and the nth node (MW)
$Up_{u,v}$	power output of the uth unit in the vth hour (MW)
$X_{n'n}$	reactance of the branch between the n'th node and the nth node (p.u.)
x_i	construction decision of the ith candidate generator {1, to be constructed; 0, otherwise}
y_j	number of circuits planned to be constructed for the jth candidate transmission line
θ_n	phase angle of the nth node

in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized" [12]. Based on this definition, DR can be divided into Price Based Demand Response (PBDR) and Incentive Based Demand Response (IBDR) [13]. Refs. [14,15] carry out theoretical research on DR and conduct case study of PBDR and IBDR. Ref. [16] shows several typical implementations of DR programs in practice. Now that DR is playing an increasingly important role in power systems, its impacts on power system planning cannot be neglected. The reduction of peak load in the target year through DR is able to decrease the capacity of generation expansion and transmission expansion [17,18]. Against this background, some scholars have executed researches on planning issues incorporating DR. Yuan et al. [17] introduce a resource planning model considering IBDR, in which load curtailment is regarded as an option for replacing generation expansion to meet peak load demand. Li et al. [18] propose a TEP model with IBDR in order to find the optimal trade-off between transmission investment and load curtailment expenses. Choi and Thomas [19] put forward a GEP model incorporating PBDR, in which the electricity demand projection is revised according to the simulated electricity price. Koltsaklis

and Georgiadis [20] present an integrated multi-regional long-term GEP model that considers the impacts of PBDR on electricity demand projection adjustments.

These researches have made great contributions to the exploration of incorporating DR in planning issues. However, more improvements need to be made, since this is still a novel and growing area. First of all, most work in this area only considers the impact of one type of DR, i.e. IBDR or PBDR, instead of considering them together. In addition, researchers tend to only take into account the effects of load curtailment while ignoring the influences of load shifting. For PBDR, most scholars focus on the forecast revision of total electricity demand rather than load profile. More importantly, DR is essentially a concept at the operation level rather than the planning level [21]. That is why more researches and models incorporating DR are in the area of operation issues, such as unit commitment and distributed dispatch [15,22–26]. When it comes to planning issues considering DR, existing researches often focus on the effect of DR on reducing peak load [17,18]. Usually, the available DR capacity at the moment when peak load appears is subtracted from the value of peak load. However, this approach tends to overestimate the effects of DR, because the load demand at another moment may actually become the new peak load after the comprehensive impacts of DR are considered [27]. This new peak load effect typically occurs in two situations that will be analyzed in detail in the following section of this paper.

Based on this background, this paper proposes a bi-level integrated Generation-Transmission Expansion Planning (GTEP) model incorporating the impacts of DR. The elements in generation side, transmission part and demand side are all taken into account simultaneously. The upper level of the model solves the planning problem. The lower level deals with the modified Unit Commitment (UC) problem considering IBDR and the process of PBDR to simulate system operation on the peak load day. The comprehensive effects of DR on actual peak load are reflected through the observation of its cross-hour influences. By virtue of the iterative interaction between the two levels of the model, a reasonably optimal solution can thus be found.

The main contributions and the most salient features of this paper include: (i) all the elements in power supply side, power transmission part and power demand side are considered together, in order to seek the optimal solution from the perspective of the whole power system; (ii) the influences of both IBDR and PBDR are considered in our planning model; (iii) UC problem is incorporated so that the proposed model is a two-level model, in which the actual comprehensive effects of DR on peak load reduction can be figured out through simulation of the whole peak load day instead of just focusing on the peak load moment; (iv) for IBDR in the model, not only load curtailment but also load shifting are considered; (v) the impacts of PBDR on load profile is reflected via the interactions between UC problem and PBDR process within the lower level of the model.

The rest of this paper is organized as follows. Section 2 discusses the impacts of DR on peak load reduction. Section 3 presents our bi-level integrated GTEP model. Section 4 describes a numerical study with result analysis to test the proposed model. Finally, conclusions are outlined in Section 5.

2. Impacts of demand response on power system planning

2.1. Introduction to IBDR and PBDR

As stated previously, DR can be divided into two main types, i.e. IBDR and PBDR. A brief introduction to them is offered in this subsection to pave the way for the presentation of our model.

IBDR refers to the changes in electricity consumption in response to incentive payments. It is also known as dispatchable DR, which indicates IBDR can be dispatched like generation units [21]. A number of studies have been carried out to incorporate IBDR in UC models or economic dispatch models [22–26]. In terms of effects, IBDR consists of load curtailment and load shifting [28]. The former effect can be treated as avoidable load. Electricity consumers may purely curtail parts of their power demand if they can earn enough financial compensation. The latter effect means consumers may shift parts of their power demand to other time periods if they receive corresponding compensation. Existing studies in the field of planning issues usually consider load curtailment, especially at the peak load moment, which means less generation capacity and transmission capacity are required to meet the peak load demand [17,18]. From another perspective, researchers sometimes ignore whether the curtailed load demand could appear at another time. Strictly speaking, this approach could bring about mistakes.

PBDR means the demand response triggered by changes in electricity price. The impacts of price on electric power consumption are typically studied within a day, as presented in Eq. (1). The matrix on the right side of the equal sign is called an elasticity matrix that is used to reflect the relationship between changes in load demand and changes in electricity price [29]. PBDR also has two forms of effects, load curtailment and load shifting. A diagonal element in the elasticity matrix (for example, e_{11}) is called self-elasticity. This elasticity reflects the load change at a certain moment according to the electricity price at this time. It consists of load shifted to other moments and pure load curtailment. An off-diagonal element in the elasticity matrix (for example, $e_{1,24}$) is called cross-elasticity. This kind of elasticity indicates the load shifted from one moment to another moment according to the electricity price changes at these two moments. Compared with IBDR, there are even fewer studies in the area of planning that consider the effects of PBDR. The existing ones tend to use a simplified way to deal with PBDR. They calculate the average cost to use electricity during a period (for example, the target year) and utilize the rate of change in the cost with self-elasticity to revise the demand projection [19,20]. The effects of PBDR on changing load profile have not been considered in these planning models.

$$\begin{bmatrix} \Delta L_1/L_1^0 \\ \Delta L_2/L_2^0 \\ \Delta L_3/L_3^0 \\ \vdots \\ \Delta L_{24}/L_{24}^0 \end{bmatrix} = \begin{bmatrix} e_{1,1} & \cdots & e_{1,24} \\ \vdots & \ddots & \vdots \\ e_{24,1} & \cdots & e_{24,24} \end{bmatrix} \cdot \begin{bmatrix} \Delta P_1/P_1^0 \\ \Delta P_2/P_2^0 \\ \Delta P_3/P_3^0 \\ \vdots \\ \Delta P_{24}/P_{24}^0 \end{bmatrix} \tag{1}$$

2.2. Actual impacts of DR on peak load reduction

In power system planning, DR is principally regarded as a resource that is able to reduce the peak load demand in the target year. Planners would like to seek an optimal trade-off between DR deployment and generation expansion or transmission expansion (or both).

However, the impacts of DR on peak load reduction may be overestimated if only the peak load moment is focused on, which is the typical approach of most studies [27]. The original peak load projection minus DR capacity is estimated to be the peak load value that should be met by generation capacity and transmission capacity. This approach may underrate the actual peak load demand. There are two typical situations in which this may occur. The first situation is that some reduced load demand could appear in later periods, which can increase the load demand at later moments such that the load demand at these moments might become the actual new peak load. Fig. 1 illustrates this situation. The black continuous curve in the figure is the daily load curve.

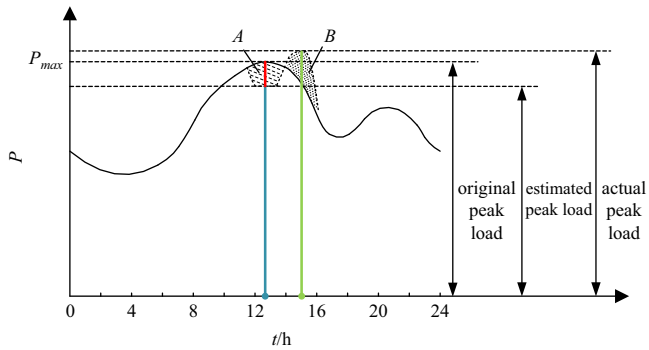

Fig. 1. Schematic diagram of the impacts of load shifting on peak load.

Area *A* indicates load reduction triggered by the system operator. But the load could appear later (Area *B*). The red line segment represents the load reduction caused by DR. The blue line segment represents the estimation of new peak load after DR if only the peak load moment is focused. However, the green line segment denotes the actual peak load demand after the comprehensive impacts of DR are considered. Apart from the peak load value, the peak load moment is also changed (from the blue dot to the green dot in the horizontal axis). The second situation is that even if the reduced load demand at the peak load moment does not shift to other moments (i.e. load curtailment only), the load demand level at another moment could still become the new peak load if the load demand at the original peak load moment decreases greatly enough. Fig. 2 represents such a situation. The blue line segment may be treated as the peak load after load curtailment. However, the actual new peak load should be the green line segment.

2.3. Effects of incorporating UC in planning model

To cope with potential mistakes in estimating DR's impacts on load demand, we recommend consideration of the effects of DR during the whole peak load day instead of just at the peak load moment. Besides, day is the typical time scale for the analysis of DR, since different days tend to share similar temporal distribution of DR potential.

UC model is an ideal choice to solve this problem. Traditionally, UC has seldom been utilized in planning, since UC is an operation level problem that focuses on the daily schedule of generators' output [30]. But DR is in fact also a concept at the day-to-day operation level, as discussed previously. Therefore, a modified UC model considering DR can better reflect the effects of DR on peak load reduction, thereby affecting planning issues. IBDR can be considered together with the dispatch of generation units within an entire day, so that the cross-hour influences of DR on the peak load can be observed. The influences of PBDR can be assessed through

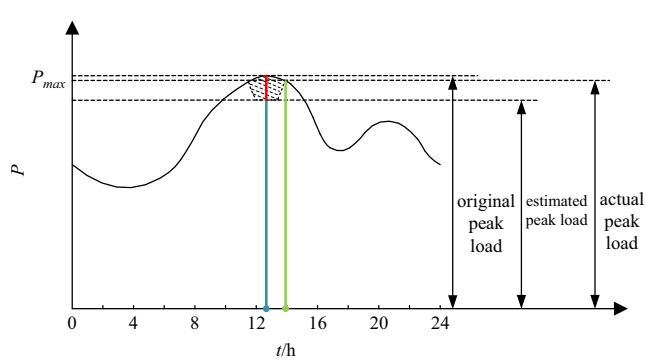

Fig. 2. Schematic diagram of the impacts of load curtailment on peak load.

an iteration mechanism between the hourly cost result of UC and the PBDR module [25]. From the results of this iteration, the actual load curve is determined. Consequently, we can find whether the peak load still appears at the original peak load moment or at another moment and what its value is. If this value is returned into the planning model, reasonable adjustments can be made to the planning results.

3. Bi-level integrated GTEP model

In this paper, a bi-level integrated GTEP model is proposed. The upper level solves the planning problem. Its model is introduced in Section 3.1. The lower level deals with the operation simulation of the peak load day in the target year. The UC model is put forward in Section 3.2. The operating procedure of the whole bi-level model including the iterative interaction mechanism is explained in Section 3.3.

3.1. Integrated GTEP model

3.1.1. Objective

The GTEP is a mixed integer nonlinear programming problem. Its objective is to minimize the overall cost, which consists of investment in generation expansion, investment in transmission expansion, operating costs of all the generation units, and cost of carbon emissions as shown in following equations.

$$\min Cost = Cost_{GE} + Cost_{TE} + Cost_{Ope} + Cost_{Emi} \tag{2}$$

$$Cost_{GE} = \sum_{i\in\Omega_g} x_i \cdot C_i \cdot G_i \tag{3}$$

$$Cost_{TE} = \sum_{j\in\Omega_l} y_j \cdot T_j \tag{4}$$

$$Cost_{Ope} = \sum_{t\in\Omega_T}\sum_{i\in\Omega_g} x_i \cdot O_i \cdot C_i \cdot H_{it} + \sum_{t\in\Omega_T}\sum_{l\in\Omega_G} O_l \cdot C_l \cdot H_{lt} + \sum_{t\in\Omega_T}\sum_{k\in\Omega_d} Od_k \cdot Cd_k \cdot H_{kt} \tag{5}$$

$$Cost_{Emi} = Pr_C \cdot \left(\sum_{t\in\Omega_T}\sum_{i\in\Omega_g} x_i \cdot E_i \cdot C_i \cdot H_{it} + \sum_{t\in\Omega_T}\sum_{l\in\Omega_G} E_l \cdot C_l \cdot H_{lt} \right) \tag{6}$$

3.1.2. Constraints

As an optimization model, the GTEP model includes several aspects of constraints as shown below.

(1) Supply-demand balance constraints

The essence of power system planning is to guarantee that the load demand and electricity demand in the future can be met. Eq. (7) is the constraint that ensures the maximum load demand is met, while Eq. (8) makes sure that electricity demand is fulfilled.

$$\sum_{i\in\Omega_g} x_i \cdot C_i + \sum_{l\in\Omega_G} C_l + \sum_{k\in\Omega_d} Cd_k \geqslant (1+\eta) \cdot Pf_t \tag{7}$$

$$\sum_{i\in\Omega_g} x_i \cdot C_i \cdot H_{it} + \sum_{l\in\Omega_G} C_l \cdot H_{lt} + \sum_{k\in\Omega_{dlc}} Cd_k \cdot H_{kt} \geqslant Ef_t \tag{8}$$

(2) Peak load regulation capacity constraint

Since more and more variable generation will be integrated in power systems in the future, the peak load regulation capacity should be taken into consideration in planning issues [31]. This

constraint ensures the regulation capacity of conventional generation can offset the variability of intermittent generation (wind, solar, etc.) and load demand, as represented in Eq. (9). As shown in the Nomenclature part, R_i/R_l means the peak load regulation capacity ratio of the ith candidate generator/the lth existing generator, where the peak load regulation capacity ratio of a generator refers to the ratio of its peak load regulation capacity to its installed capacity [31].

$$\sum_{\substack{i\in\Omega_g\\ i\notin\Omega_{vg}}} x_i\cdot R_i\cdot C_i+\sum_{\substack{l\in\Omega_G\\ l\notin\Omega_{vG}}} R_l\cdot C_l+\sum_{k\in\Omega_d} Cd_k \geqslant \beta\cdot P_t+\sum_{i\in\Omega_{vg}} x_i\cdot C_i+\sum_{l\in\Omega_{vG}} C_l \quad (9)$$

(3) Expansion scale constraints

Generation expansion scale, transmission expansion scale and demand response potential are also taken into account in the model. Eq. (10) denotes the upper limits on the number of new generation units to be built. Eq. (11) and Eq. (12) respectively show the upper limits on the number of circuits in each transmission channel and the total number of new transmission lines. Eq. (13) indicates the upper bound of available demand response resources.

$$\sum_{i\in\Omega_g} x_i \leqslant X_{\max} \quad (10)$$

$$0 \leqslant y_j \leqslant Nl_{j,\max} \quad (11)$$

$$\sum_{j\in\Omega_l} \mathrm{sign}(y_j) \leqslant Y_{\max} \quad (12)$$

$$Cd_k \leqslant Cd_{k,\max} \quad (13)$$

(4) Power flow constraints

In order to ensure that the expansion scheme can meet the requirements of power system operation in the target year, constraints on grid network operation at the peak load moment should be considered. Eq. (14) ensures that the output of each unit is within a reasonable range. Eq. (15) refers to the power balance at each node. Eq. (16) puts an upper bound on the power flow of each transmission line. Eq. (17) shows constraints on the phase angle of each node.

$$Pg_i \leqslant C_i \quad i\in\Omega_g,\Omega_G \quad (14)$$

$$Pg_n - Pd_n = \sum_{n'=1}^{N} \frac{\theta_{n'}-\theta_n}{X_{n'n}} \quad (15)$$

$$\left|\frac{\theta_{n'}-\theta_n}{X_{n'n}}\right| \leqslant \underset{n'n}{\mathrm{Pmax}} \quad (16)$$

$$\theta_{n,\min} \leqslant \theta_n \leqslant \theta_{n,\max} \quad (17)$$

(5) Carbon emission constraint

Eq. (18) represents the constraint on total carbon emissions of the power system.

$$\sum_{t\in\Omega_T}\sum_{i\in\Omega_g} x_i\cdot e_i\cdot C_i\cdot H_{it}+\sum_{t\in\Omega_T}\sum_{l\in\Omega_G} e_l\cdot C_l\cdot H_{lt} \leqslant Uce \quad (18)$$

3.2. UC model

3.2.1. Objective

Modifications have been made on a traditional UC model so that the IBDR can be dispatched together with generation units. The UC model is also a mixed integer nonlinear optimization problem. It aims to find the optimal schedule for daily operation. The objective is to minimize the overall cost including fuel cost, start up cost and shut down cost of generators and incentive cost of demand response as shown in Eq. (19).

$$\begin{aligned}\min C_{UC} &= \sum_{v=1}^{24}\sum_{u=1}^{U}[FC_u\cdot Up_{u,v}+I_{u,v}(1-I_{u,v-1})\cdot SUC_u+(1-I_{u,v})\\ &\quad\cdot I_{u,v-1}\cdot SDC_u]+\sum_{v=1}^{24}\sum_{n=1}^{N}[Clc\cdot Lc_{n,v}+Cls\cdot\max\{0,Ls_{n,v}\}]\end{aligned} \quad (19)$$

3.2.2. Constraints

Conventionally, UC model has constraints related to the output of generators, constraints related to the operation of grid network, and constraints related to the reserves in the system. In this modified UC model considering DR, relevant constraints on DR should also be taken into account to ensure the reasonable utilization of this resource.

(1) Generation output constraints

The output of each generator should meet certain requirements for unit performance and operating status. The Eq. (20) represents the upper and lower limits on the power output of each generation unit. Eq. (21) and Eq. (22) respectively denote the ramp-up rate and ramp-down rate of each unit. Eqs. (23) and (24) indicate the minimum on and off time of each unit.

$$Upmin_u\cdot I_{u,v} \leqslant Up_{u,v} \leqslant \underset{u}{Upmax}\cdot I_{u,v} \quad (20)$$

$$Up_{u,v}-Up_{u,v-1} \leqslant Rur_u \quad (21)$$

$$Up_{u,v-1}-Up_{u,v} \leqslant Rdr_u \quad (22)$$

$$\sum_{v'=v+1}^{v+MU_u}(1-I_{u,v'})+(I_{u,v}-I_{u,v-1})\cdot MU_u \leqslant MU_u \quad (23)$$

$$\sum_{v'=v+1}^{v+MD_u} I_{u,v'}+(I_{u,v-1}-I_{u,v})\cdot MD_u \leqslant MD_u \quad (24)$$

(2) Network operation constraints

The dispatch of various units determines the operating status of the grid network. Therefore, limits at each node and each branch should be considered during the process of UC. Eq. (25) ensures the power balance at each node in the system. Eq. (26) shows the upper bound and lower bound on the phase angle of each node. Eq. (27) defines the constraint on power flow transmission in the branch in the system.

$$Pg_{n,v}-Pd_{n,v}=\sum_{n'=1}^{N}\frac{\theta_{n',v}-\theta_{n,v}}{X_{n'n}} \quad (25)$$

$$\theta_{n,\min} \leqslant \theta_{n,v} \leqslant \theta_{n,\max} \quad (26)$$

$$\left|\frac{\theta_{n',v}-\theta_{n,v}}{X_{n'n}}\right| \leqslant P_{n'n,\max} \quad (27)$$

(3) Reserve constraints

Reserve is a very crucial issue for power systems, so relevant constraints should be taken into account in the UC model. An increasing amount of intermittent generation renders this issue more important for the safe operation of power systems, so we choose a way to calculate the requirements of reserves in which intermittent generation are treated differently from conventional

generation. Eqs. (28) and (29) refer to the requirements of total contingency reserve and spinning reserve in the system, where $CR1$ is 5% of hydro generation + 7% of other conventional generation (excluding intermittent generation) + 10% of intermittent generation (wind power, solar power, etc.), and $CR2$ is the power loss due to the outage of the largest generating unit at each hour [32].

$$\sum_{u=1}^{U}(1-I_{u,v})\cdot Upmax_u \geqslant \max\{CR1, CR2\} \tag{28}$$

$$\sum_{u=1}^{U}I_{u,v}\cdot(Upmax_u - Up_{u,v}) \geqslant 0.5\cdot\max\{CR1, CR2\} \tag{29}$$

(4) Demand response constraints

Since DR is considered in this modified UC model, constraints should be set to reflect the potential limits and operation requirements of DR. Eqs. (30) and (31) limit the potential power of load curtailment and load shifting at each node at each time. Eqs. (32) and (33) represent the potential amount of electricity curtailment and electricity shifting within the whole day. Eq. (34) means the load shifting balance during the day at each node.

$$Lc_{n,v} \leqslant Lc_{n,v,\max} \tag{30}$$

$$Ls_{n,v} \leqslant Ls_{n,v,\max} \tag{31}$$

$$\sum_{v=1}^{24}Lc_{n,v} \leqslant Lc_{n,\max} \tag{32}$$

$$\sum_{v=1}^{24}\max\{0, Ls_{n,v}\} \leqslant Ls_{n,\max} \tag{33}$$

$$\sum_{v=1}^{24}Ls_{n,v} = 0 \tag{34}$$

3.3. Bi-level integrated GTEP model

As stated before, the integrated planning model proposed in this paper consists of two levels. The upper level solves the GTEP problem introduced in Section 3.1. The lower level deals with the UC problem considering IBDR put forward in Section 3.2 and the process of PBDR presented in Section 2. The schematic diagram of the bi-level model is depicted in Fig. 3.

The upper level of the model transfers the results of generation expansion and transmission expansion to the lower level. The lower level aims to simulate the operation of the peak load day in the target year to test the planning results. The actual effects of IBDR and PBDR are embodied in the lower level. Firstly, a solution to the UC problem with IBDR is worked out. Then, the hourly cost to consume electric power is calculated and passed to the PBDR module in which the load profile is adjusted accordingly. The updated load demand curve is transmitted back. The UC problem is solved again, which means the hourly electricity consumption cost will also change. The loop repeats until the difference between the actual peak load values in two adjacent iterations is lower than a predefined threshold. After that, the lower level finishes its work and offers some feedback, the actual peak load demand in the system and the load demand at each bus at the actual peak load moment, to the upper level. The upper level will consequently revise the solution to the GTEP problem. The iteration loop between the upper level and the lower level will not stop until the planning results in two adjacent iterations are the same. The program flowchart of the whole model is illustrated in Fig. 4.

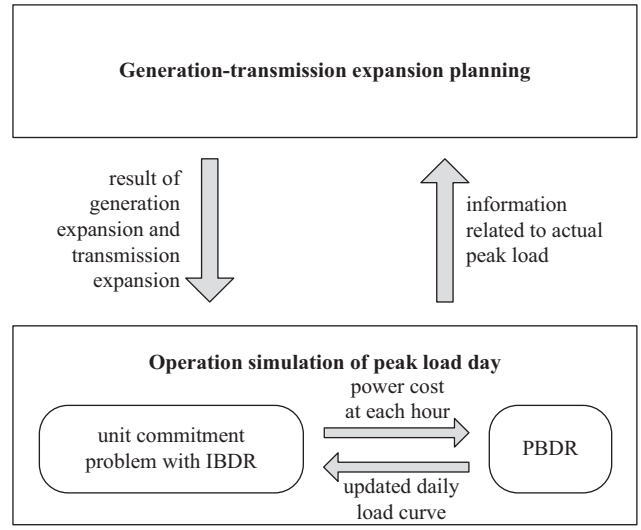

Fig. 3. Schematic diagram of the bi-level planning model.

The interactions between the two levels are very important, not only because the planning results can be tested with the operation simulation for the peak load day to ensure its effectiveness, but also because the actual comprehensive effects of DR can be reflected. If the impacts of DR are only considered at the peak load moment, its effects on reducing load demand tend to be overestimated as stated in Section 2. As a consequence, the generation capacity and transmission capacity may not be enough for the secure operation of the system.

4. Numerical study

4.1. Input data and scenario settings

In order to verify the effectiveness of the proposed model, a numerical study is carried out based on the IEEE 30 bus system which is a very common choice in researches on power system planning issues [8,33–37]. The system contains 6 generation units, 30 node buses and 41 transmission lines. The first bus node serves as the balance node in the system. The construction time of each unit and transmission line is not considered in this study. The parameters of generation unit candidates are shown in Table 1 [38]. The information on transmission line candidates is listed in Table 2 [39,40]. The maximum number of circuits in each transmission line is two.

It is assumed that there is IBDR potential at Bus 5, Bus 7, Bus 8 and Bus 21. There are low DR potential scenario and high DR potential scenario in terms of the amount of available DR resources in this numerical study, in order to test the influences of different scales of DR potential. The form, upper bound, available time and cost of these DR resources in low DR potential scenario and high DR potential scenario are presented in Table 3 and Table 4, respectively. The elasticity matrix for PBDR is from Ref. [41].

Other parameters in the model are set as follows. The planning is oriented to target year and the planning period is 10 years. The peak load demand at each node is forecasted to increase by 50% during the period. The load curve shape is from Ref. [42]. The forecast of electricity demand in the target year is 2000 GW h. The carbon emissions trading price is 52 yuan/ton [43]. The reserve rate is 30%. The maximum number of new generation units is 5. The maximum number of new transmission lines is 10. The upper limit on annual carbon dioxide emissions is 3000 thousand tons.

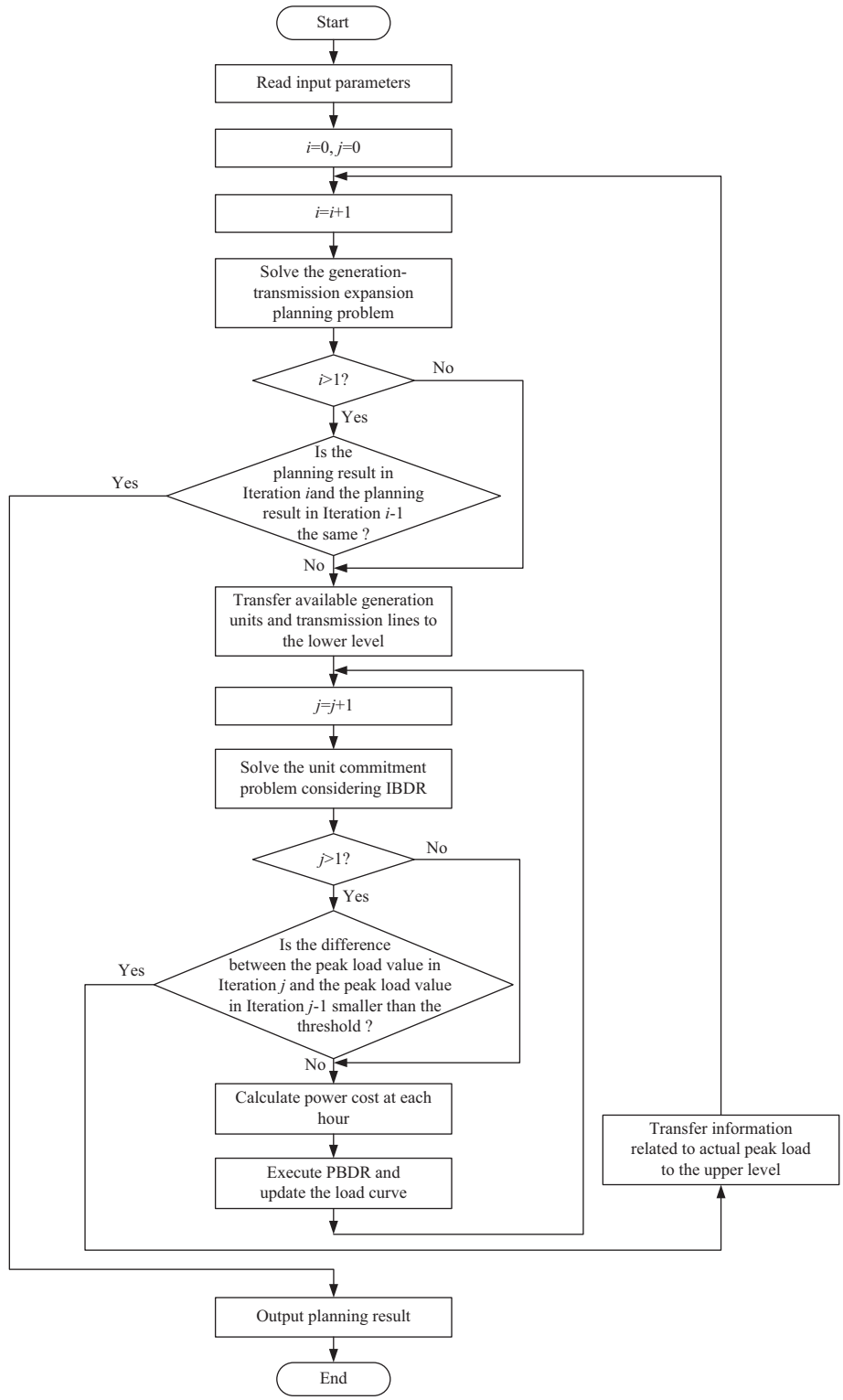

Fig. 4. Flowchart of the planning model.

There are five scenarios in total in the numerical study, as expressed in Table 5. In Scenario 1, DR is not considered. The GTEP problem is solved by the single-level planning model introduced in Section 3.1, since the bi-level model is almost unnecessary if no DR is taken into account. In Scenario 2 and Scenario 3, GTEP is carried out with low DR potential as shown in Table 3. The model used in Scenario 2 is simply the planning model presented in Section 3.1, while the model used in Scenario 3 is the whole bi-level planning model. In Scenario 4 and Scenario 5, it is assumed that there is greater DR potential as shown in Table 4. The planning problem in Scenario 4 is solved with the single-level planning model, while the solution to the problem in Scenario 5 is found with the bi-level planning model.

The model is constructed and solved in GAMS [44]. The solver is BONMIN (Basic Open-source Nonlinear Mixed INteger

Table 1
Generation unit candidates.

No.	Site	Energy source	Capacity (MW)	Peak-load regulation capacity ratio (%)	Carbon dioxide emissions factor (kg/MW h)	Annual utilization hours	Investment cost (Million yuan[a] /MW)	Operating cost (yuan/MW h)
G1	24	Coal	100/200/300	50	880	5000	3.60	400
G2	29	Coal	100/200/300	50	880	5000	3.72	400
G3	19	Gas	50/100/150	100	460	3500	3.22	600
G4	20	Gas	100/200/300	100	460	3500	3.22	600
G5	24	Wind	50/100/150	100	0	2000	9.50	20
G6	15	Wind	50/100/150	100	0	2000	8.50	20

[a] Yuan is the monetary unit in the People's Republic of China. 1 yuan ≈ 0.155 dollar.

Table 2
Transmission line candidates.

No.	Starting node No.	Terminal node No.	Capacity (MW)	X (p.u.)	Investment cost (Million yuan)	No.	Starting node No.	Terminal node No.	Capacity (MW)	X (p.u.)	Investment cost (Million yuan)
T1	1	2	30	0.06	50	T15	9	10	50	0.11	90
T2	1	3	15	0.19	50	T16	9	11	60	0.21	80
T3	2	4	10	0.17	50	T17	10	20	10	0.21	50
T4	2	5	30	0.20	60	T18	10	21	20	0.07	80
T5	2	6	10	0.18	50	T19	10	22	10	0.15	50
T6	3	4	10	0.04	50	T20	12	13	40	0.14	60
T7	4	6	10	0.04	50	T21	12	15	20	0.13	60
T8	4	12	10	0.26	40	T22	12	16	10	0.20	50
T9	5	7	15	0.12	70	T23	15	18	10	0.22	50
T10	6	7	40	0.08	60	T24	16	17	10	0.19	50
T11	6	8	25	0.04	50	T25	18	19	10	0.13	50
T12	6	9	15	0.21	70	T26	22	24	10	0.18	50
T13	6	10	10	0.56	60	T27	27	28	10	0.40	50
T14	6	28	10	0.06	50						

Table 3
IBDR resources (low DR potential scenario).

Bus	Form	Response power upper bound (MW)	Daily response electricity upper bound (MW h)	Available time	Cost (yuan/MW h)
Bus 5	Load curtailment	32	32	10am–1 pm	400
Bus 7	Load shifting	12	24	8 pm–10 pm	300
Bus 8	Load shifting	18	36	11am–3 pm	300
Bus 21	Load curtailment	8	8	12 pm	400

Table 4
IBDR resources (high DR potential scenario).

Bus	Form	Response power upper bound (MW)	Daily response electricity upper bound (MW h)	Available time	Cost (yuan)
Bus 5	Load curtailment	48	48	9am–1 pm	400
Bus 7	Load shifting	24	48	8 pm–11 pm	300
Bus 8	Load shifting	36	72	11am–5 pm	300
Bus 21	Load curtailment	12	12	12 pm	400

Table 5
Scenario settings.

Scenario No.	DR potential			Model	
	None	Low	High	Single-level planning	Bi-level planning
Scenario 1	√			√	
Scenario 2		√		√	
Scenario 3		√			√
Scenario 4			√	√	
Scenario 5			√		√

Table 6
Computation time in each scenario.

Scenario No.	Computation time (s)
Scenario 1	8.7
Scenario 2	11.4
Scenario 3	213.6
Scenario 4	12.9
Scenario 5	367.2

programming), which is capable of solving mixed integer nonlinear programming problems [45]. All the work is implemented on a computer with Intel Core 2.50 GHz and 4 GB RAM.

4.2. Principle results

Planning solution can be found through running the model with the computation time shown in Table 6. Planning results including generation expansion scheme and transmission expansion scheme in each scenario are listed in Table 7. The number in the parentheses in the transmission expansion results indicates the number of circuits in each transmission line [40]. The total expansion capacity of generation and transmission in each scenario is listed in Fig. 5. Various types of costs are presented in Fig. 6.

The original load curve and actual load curve after DR in Scenario 3 are shown in Fig. 7. The blue curve is the forecast load curve in the peak load day in the target year, which is an input parameter in the planning model. The load curve is initially used at the lower level in the bi-level planning model to simulate the system operation, in order to figure out the actual effect of DR on reducing the peak load. The red curve corresponds to the actual load demand

Table 7
Planning results in each scenario.

Scenario No.	Generation expansion	Transmission expansion
Scenario 1	G1(100 MW), G2(100 MW), G4(100 MW), G5(50 MW)	T4(1), T17(2), T11(1), T19(2)
Scenario 2	G1(100 MW), G3(50 MW), G5(50 MW), G6(50 MW)	–
Scenario 3	G1(100 MW), G3(50 MW), G4(100 MW), G6(50 MW)	T1(1), T11(1), T24(1)
Scenario 4	G1(100 MW), G5(50 MW), G6(50 MW)	–
Scenario 5	G2(100 MW), G3(50 MW), G5(50 MW), G6(50 MW)	T11(1)

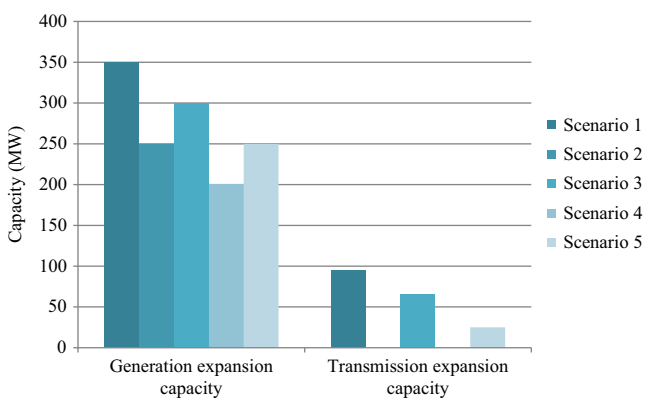

Fig. 5. Expansion capacity in each scenario.

that needs to be met by generation units through transmission lines. The difference between these two curves is caused by IBDR and PBDR. Similarly, the original load curve and actual load curve after DR in Scenario 5 are shown in Fig. 8. The difference between the actual load curve and the original load curve is larger in Scenario 5 than in Scenario 3, because there are more available DR resources in Scenario 5.

The highest point of the blue curve is the peak load forecast. As shown in Fig. 7 and Fig. 8, not only the peak load value but also the peak load moment have been changed by DR in Scenario 3 and Scenario 5. The original peak load and actual peak load after DR in these two scenarios are listed in Table 8. Besides, the estimated peak load by the traditional approach (used in Scenario 2 and Scenario 4), i.e., the forecasting value of peak load minus the capacity of DR, is also presented in Table 8.

In both scenarios, the peak load is reduced by virtue of DR. But the reduction effects are overestimated by traditional approaches adopted in existing planning issues, which means that peak load is underestimated. Fig. 9 depicts the estimated peak load reduction rate, actual peak load reduction rate and peak load underestimation rate in low DR potential scenario and high DR potential scenario.

4.3. Discussion

4.3.1. Positive impacts of DR on the planning results

Through the comparison of the results in Scenario 1, Scenario 3 and Scenario 5, the impacts of DR can be verified. Firstly, generation expansion capacity and transmission expansion capacity are reduced. In Scenario 1, the capacities of generation expansion and transmission expansion are 350 MW and 95 MW, respectively. In Scenario 3, they are reduced to 300 MW and 65 MW due to the effects of DR. In Scenario 5, they are further decreased to 250 MW and 25 MW when more DR resources are available. Secondly, the numbers of transmission lines and total circuits to be constructed are reduced. In Scenario 1, the numbers of lines and circuits are 4 and 6, respectively. In Scenario 3, the numbers are lowered to 3 and 3. In Scenario 5, the results are 1 and 1. Thirdly, various costs decline by virtue of DR. The generation expansion cost and transmission expansion cost in Scenario 3 and in Scenario 5 are respectively lower than those in Scenario 1. In terms of operating cost and carbon emissions cost, Scenario 3 and in Scenario 5 also have better performance. When it comes to the overall cost of the planning problem, the result in Scenario 3 is 9.1% lower than that in Scenario 1, and the result in Scenario 5 is 21.8% lower than that in Scenario 1 as shown in Fig. 6. The mechanism by which these benefits accrue is that DR drives down the peak load. We conclude that DR has greatly positive impacts on power system planning. Besides, the impacts will be greater if more DR participations are taken into account, since Scenario 5 has even better performances than Scenario 3 in terms of various indicators. In summary, DR is of great importance for power systems.

4.3.2. Significance of the bi-level model in estimating the actual impacts of DR

This paper proposes a bi-level planning model that incorporates the operation simulation of the peak load day, in order to reflect the actual impacts of DR on peak load reduction. If traditional planning approaches are utilized, the planning results will be that in Scenario 2 and Scenario 4. Therefore, through the comparison between Scenario 3 and Scenario 2 as well as the comparison

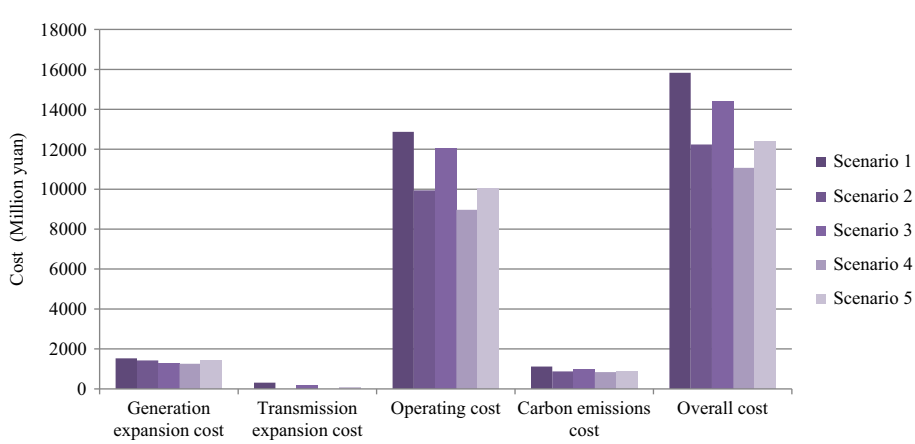

Fig. 6. Various costs in each scenario.

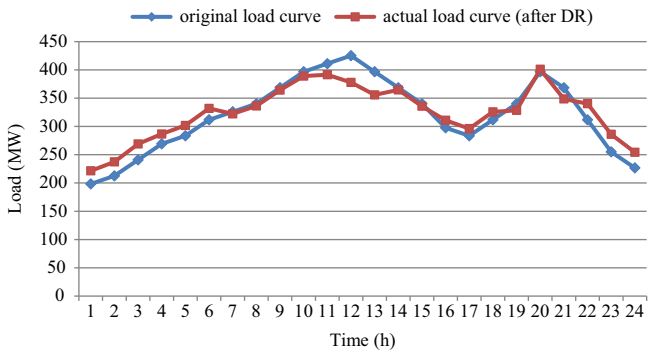

Fig. 7. Original load curve and actual load curve in Scenario 3.

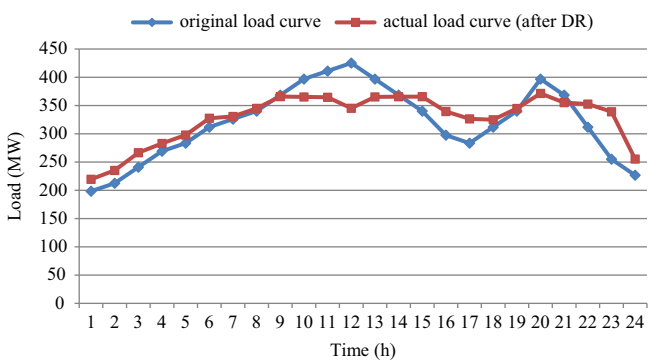

Fig. 8. Original load curve and actual load curve in Scenario 5.

Table 8
Peak load information in low DR potential scenario and high DR potential scenario.

	Low DR potential scenario	High DR potential scenario
Original peak load (MW)	425.1	425.1
Estimated peak load after DR (MW)	355.1	305.1
Actual peak load after DR (MW)	401.1	371.4

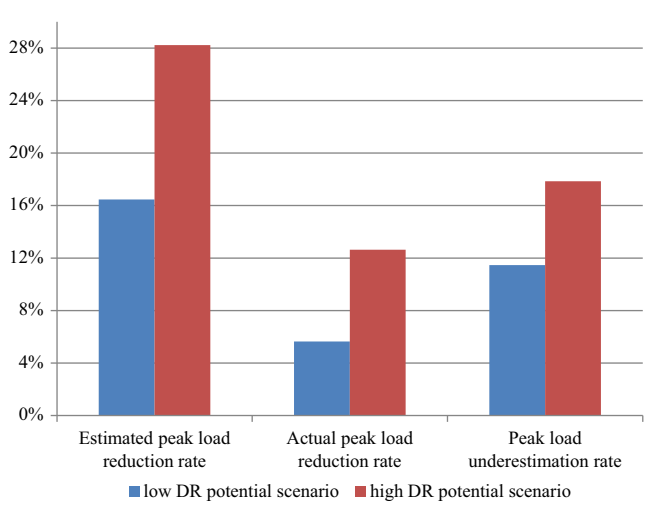

Fig. 9. Peak load reduction rate and peak load underestimation rate in low DR potential scenario and high DR potential scenario.

between Scenario 5 and Scenario 4, the significance of the bi-level model can be verified.

The contribution of DR to planning is made by means of peak load reduction. Existing approaches usually focus on power reduction at the peak load moment. However, the load demand at another moment (before or after the original peak load moment) may unexpectedly become the new peak load as a result of DR. Therefore, traditional approaches may overestimate the effects of DR on decreasing peak load, which is verified by the planning results in the numerical study. The generation expansion capacity in Scenario 2 is lower than that in Scenario 3, and so is the transmission expansion capacity. Similarly, the capacity of generation expansion and transmission expansion in Scenario 4 are lower than those in Scenario 5. However, these reductions in expansion capacity are not reasonable, because even though the load demand at the original peak load moment can be met, the actual peak load demand caused by DR that appears at another moment may not be met. As shown in Table 8, the peak load is always underestimated by the single-level planning model. The underestimated rate is 11.5% in low DR potential scenario and 17.9% in high DR potential scenario. As shown in the planning results, the underestimated rate is large enough to have adverse effects on obtaining a reasonable planning result. Moreover, the influence would be even more exacerbated with the increase of the available amount of DR. The actual new peak load value should be between the original peak load value and the new load value at the original peak load moment. Therefore, the single-level planning model may offer an irrational planning result, while the bi-level planning model can ensure that the expansion of generation and transmission is able to meet the load demand at every moment.

5. Conclusion

This paper proposes a bi-level integrated generation-transmission expansion planning model in order to seek an optimal expansion scheme for the whole power system. GEP and TEP are combined together. Moreover, the impacts of DR are taken into account. The planning model incorporates a lower level to simulate the operation of the peak load day in the target year. A modified UC model is utilized at this level. IBDR is considered in the UC model, and there is an interaction mechanism between PBDR and the UC model at the lower level. Through the iteration of interactions between the upper level and the lower level, the comprehensive impacts of DR can be reflected. Particularly, the actual peak load can be determined more precisely. Therefore, a reasonable planning result can be obtained.

The numerical study verifies the effectiveness of the proposed model. Through the results analysis of the case study, significances of the novel planning approach are found. On one hand, DR is able to contribute to the decrease of generation expansion capacity and transmission expansion capacity. Consequently, the overall cost of the planning issue can be significantly decreased. On the other hand, the bi-level model including the operation simulation of the peak load day can more accurately approximate the actual impacts of DR on peak load reduction. Thus, this model is capable of preventing inadequate expansion of generation and transmission. The case study is representative, since it contains comprehensive contents for power system planning issues. When the model is applied to a power system in reality, the main difference lies in specific parameters, so the model should also make sense.

This study is a first attempt to build the bi-level GTEP model incorporating the effects of DR. Apart from its advantages, it inevitably has certain drawback. The computational cost will largely increase when the planning for all the elements in supple side, grid part and demand side are carried out simultaneously, especially

two sorts of iteration are constructed in the model to comprehensively and accurately reflect the impacts of DR. As a result, high-performance computers are necessary if the model is applied to a large scale power system.

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