The Optimization of CPP Strategy based on Load Data Analysis

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Abstract—This paper analyzes the optimization of critical peak pricing(CPP) policy. It includes two aspects: the selection of CPP dates and CPP time intervals, and the determination of electricity prices at CPP days. For the former aspect, temperature -triggering method is employed to determine the CPP dates, and the frequency distribution of the time intervals where critical peak loads(CPLs) appear is used to determine the CPP time intervals. For the latter aspect, firstly the load response model under CPP based on load-price elasticity and load transfer potential(LTP) is built. Then with the objective of cutting critical peak loads(CPLs), the optimization model is established and solved to obtain the optimal pricing strategy on CPP days, considering the fee balance mode and the fee increase mode. The results show that the second mode surpasses the first mode.

Index Terms—Fee balance mode, fee increase mode, load-price elasticity, load transfer potential.

I. INTRODUCTION

Energy crisis is now a big challenge for human beings, therefore the scientific ways of the energy consumption are of more concern. As a major energy, electricity is no exception. Critical peak pricing(CPP) policy is the incentive-based demand side management method. It guides the effective use of electricity by increasing electricity price at high demand periods and decreasing it at low demand periods.

There are many practices of CPP policy in China and abroad. For example, the CPP policy, implemented by the power company of Wisconsin, U.S., specifies that the consumers are informed of the CPP implementation before 19:00 of the previous day and the electricity price is 7 times of regular price; the policy is effective on load shifting. As another example, in Shandong Province of China, the CPP policy is implemented from June to August, and the electricity price at CPP time intervals is increased by 70% of the regular peak price.

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CPP strategies have been studied in many literatures. In [1], load forecasting method is used for CPP day triggering and clustering method is used for CPP time interval selection; then a dynamic decision-making model is proposed to optimize the peak rate and the rebate, considering the influence of electric vehicles. Literature [2] uses Great Britain power market index prices and market index volumes to statistically analyze the electricity price distribution and demand distribution, and lay a foundation for the future Britain CPP tariff design. Literature [3] uses the CPP policy to attack the problem of wind power curtailment, integrating the interests of wind farms, power consumers, and power company. In [4], critical peak pricing with load control in a cost-emission-based unit commitment model is investigated. In [5], the profit of energy service provider(ESP) for CPP implementation is maximized through the timing of CPP implementation, which is based on predicting the market electricity prices and evaluating a swing option.

This paper optimizes the CPP policy based on load data and provides a reference for the formulation of CPP policies in practice.

II. CPP DATE AND TIME INTERVAL SELECTION

The screening of CPP dates is to locate the date when critical peak loads(CPLs) arise. Due to the strong correlation between load and temperature, temperature triggering is used for this purpose.

The CPP time intervals can be selected based on the frequency distribution of the time intervals where CPLs arise.

III. LOAD RESPONSE MODEL

The pricing strategy of CPP policy investigated in this paper involves the electricity price increase at CPP time intervals and the decrease at valley pricing(VP) time intervals. The electricity price at CPP time intervals is unique in this paper; that is, if there are multiple separate CPP time intervals, the electricity price at these time intervals are equal.

Define the load-price elasticity as

$$\varepsilon_t = \frac{|\Delta Q_t|}{|\Delta p_t|} \tag{1}$$

where ε_t is the load-price elasticity at time t, $|\Delta Q_t|$ is the absolute value of power consumption change at time *t*, and $|\Delta p_t|$ is the absolute value of electricity price change at time *t*.

Due to the electricity price lift at CPP time intervals, the loads of these intervals drop. There are two reasons behind the load drop: some loads are just shut down under CPP policy, and others are transferred to non-CPP time intervals. The CPP load transfer factor is defined as the proportion of CPP load drop that results from the load transfer to non-CPP time intervals. As loads at CPP time intervals tend to transfer to time intervals with higher load-price elasticity and lower electricity price, the CPP load transfer potential(LTP) is defined as

$$LTP_{cpp\ ij} = |p_i - p_j| \times \varepsilon_j \tag{2}$$

where i and j are the ordinal numbers of CPP and non-CPP time intervals respectively; p_i and p_j are the electricity prices at corresponding time intervals; ε_j is the load-price elasticity at the *j*th non-CPP time interval. Then the CPP loads transferred to non-CPP time intervals are distributed proportionately according to the corresponding LTPs.

Similarly, the electricity price drop at VP time intervals results in its load increase that also divides into two parts: the newly switched-on loads and the transferred loads. Then, the VP load transfer factor is defined as the proportion of VP load increase under CPP policy that results from the non-VP load transfer. As the time intervals with higher load-price elasticity and higher electricity prices tend to transfer more loads to VP time intervals, the VP load transfer potential is defined as

$$LTP_{vp\ ij} = |p'_i - p'_j| \times \varepsilon'_j \tag{3}$$

where i and j are ordinal numbers of the VP and non-VP time intervals respectively; p'_i and p'_j are the electricity prices at corresponding time intervals; ε'_j is the load-price elasticity at the *j*th non-VP time interval. Then the non-VP loads transferred to VP time intervals are distributed proportionately according to the corresponding LTPs.

IV. PRICING OPTIMIZATION ON CPP DAYS

In this paper, two CPP modes are investigated, that is, the fee balance mode and the fee increase mode. The former keeps the total electricity fees that the power company collects before and after CPP implementation equal. The latter does not follow such criterion; instead, it uses the fee increase under CPP policy to purchase interruptible load(IL) service and further cut the CPLs.

A. Pricing Optimization for Fee Balance Mode

The primary purpose of CPP policy is to cut CPLs and improve the efficiency of power system. So the objective function is set as the minimization of the maximum load of all CPP days.

As for the constraints, the total electricity fees that the power company collects before and after CPP implementation are equal. Besides, in order to reduce risk, the magnitude of price adjustments at CPP and VP time intervals must be set within certain limits. The optimization model is as follows.

$$\min \max_{\substack{1\le i\le N_{cp}\\ 1\le j\le N_T}} (P(dp_1, dp_2)_{ij}) \tag{4}$$

$$\begin{aligned} s.t.\ & \sum_{i=1}^{N_{cp}}\sum_{j=1}^{N_T} p(dp_1, dp_2)_j \cdot P(dp_1, dp_2)_{ij} - \\ & \sum_{i=1}^{N_{cp}}\sum_{j=1}^{N_T} p(0,0)_j \cdot P(0,0)_{ij} = 0 \end{aligned} \tag{5}$$

$$0 \le dp_1 \le \Delta_1 \tag{6}$$

$$0 \le dp_2 \le \Delta_2 \tag{7}$$

where i is the ordinal number of CPP days, $1 \le i \le N_{cp}$, $i \in \mathrm{Z}$; j is the ordinal number of time units of a day, $1 \le j \le N_T$, $j \in \mathrm{Z}$; dp_1 is the electricity price increase at CPP time intervals with respect to the electricity price at peak pricing(PP) time intervals, and dp_2 is the electricity price decrease at VP time intervals; $p(dp_1, dp_2)_j$ is the electricity price function at time unit j of a day with respect to dp_1 and dp_2; $P(dp_1, dp_2)_{ij}$ is the load function at time unit j of CPP day i with respect to dp_1 and dp_2; if dp_1 and dp_2 are both put as zero, i.e., $p(0,0)_j$ and $P(0,0)_{ij}$, it denotes the situation where CPP policy is not implemented; Δ_1 and Δ_2 denote the upper limits of dp_1 and dp_2 respectively.

B. Pricing Optimization for Fee Increase Mode

The objective function for fee increase mode is identical to that for fee balance mode.

In this mode, the fee increase is used for interruptible load(IL) purchases at CPP time intervals; hence there is an equality constraint that the IL purchase cost equals the electricity fee increase. Also, there are minimum up- and down-time constraints for ILs. Besides, for risk reduction, the fee increase and electricity price adjustments should be within proper bounds. The optimization model is as follows.

$$\min \max_{\substack{1\le i\le N_{cp}\\ 1\le j\le N_T}} (P(dp_1, dp_2)_{ij} - \sum_{k=1}^{N_{IL}} PI_{ij}^k) \tag{8}$$

$$\begin{aligned} s.t.\ dR = & \sum_{i=1}^{N_{cp}}\sum_{j=1}^{N_T} \{p(dp, dp_2)_j \cdot [P(dp_1, dp_2)_{ij} - \\ & \sum_{k=1}^{N_{IL}} PI_{ij}^k]\} - \sum_{i=1}^{N_{cp}}\sum_{j=1}^{N_T} p(0,0)_{\mathrm{j}} \cdot P(0,0)_{ij} \le \Delta \end{aligned} \tag{9}$$

$$\sum_{i=1}^{N_{cp}}\sum_{j=1}^{N_T}\sum_{k=1}^{N_{IL}} pi^k \cdot PI_{ij}^k = dR \tag{10}$$

$$PI_{\min}^k \cdot S_{ij}^k \le PI_{ij}^k \le PI_{\max}^k \cdot S_{ij}^k \tag{11}$$

$$S_{ij}^k = 0,\ \text{if } j \notin \mathrm{SET}_{cpp} \tag{12}$$

$$S_{ij}^{k\ \text{on}} \ge S_{\min}^{k\ \text{on}},\ S_{ij}^{k\ \text{off}} \ge S_{\min}^{k\ \text{off}} \tag{13}$$

$$0 \le dp_1 \le \Delta_1 \tag{14}$$

$$0 \le dp_2 \le \Delta_2 \tag{15}$$

where k is the IL ordinal number, $1 \le k \le N_{IL}$, $k \in \mathrm{Z}$;

dR is the fee increase under CPP policy; $\overline{dR}$ is the fee increase upper bound; Δ is the amount of interrupted load for the kth IL at time unit j of CPP day i; pi^k denotes the interruption price of the kth IL; $PI_{\min}^k$ and $PI_{\max}^k$ are the minimum and maximum interruptible capacity; S_{ij}^k denotes the on-off state of the kth IL, and S_{ij}^k is 0-1 integer variable; SET_{cpp} is the set of the ordinal numbers of CPP time units. $S_{ij}^{k\text{ on}}$ and $S_{ij}^{k\text{ off}}$ are the up- and down-time of interruption, and $S_{\min}^{k\text{ on}}$ and $S_{\min}^{k\text{ off}}$ are the corresponding lower limits respectively; other variables are the same as those in fee balance mode.

V. CASE STUDY

A. Screening of CPP Dates

The load data of one area are used for the case study. Because CPLs only appear in July and August at this area, so analysis is conducted only on those days. The 24-point daily load profiles of the two months are shown in Fig. 1.

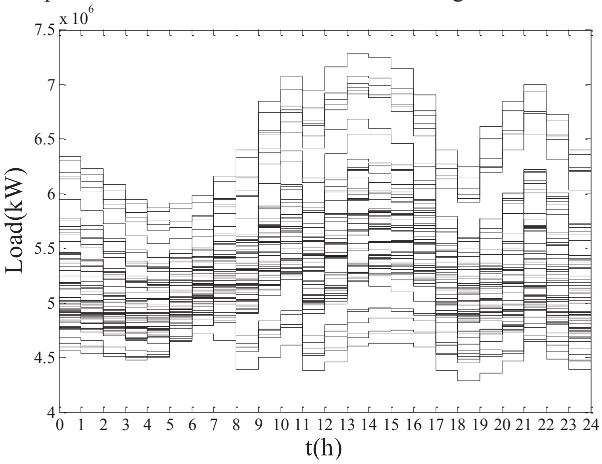

Fig. 1 The 24-point daily load profiles in July and August of the research area

To simplify the analysis, suppose the CPP policy is implemented on customers previously under the same electricity price policy. The aggregated load profiles of these customers in July and August are shown below.

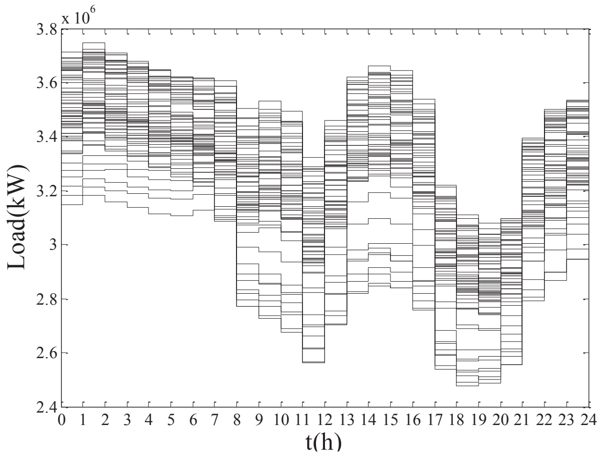

Fig. 2 The aggregated 24-point daily load profiles of CPP target customers in July and August.

According to temperature and load data of the area, the plot of maximum daily temperature and maximum daily loads of the workdays in July and August is shown below.

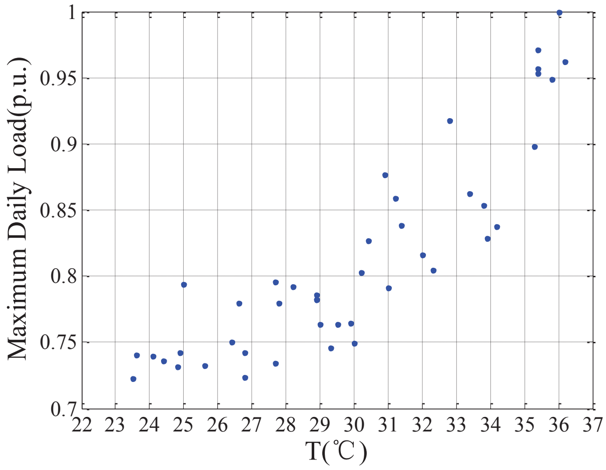

Fig. 3 The relationship between maximum daily load and maximum daily temperature.

In the figure, the maximum daily load(p.u.) is the ratio of the maximum daily load to the yearly maximum load.

Define CPL as the load greater than or equal to 95% of the yearly maximum load. Then, as indicated in Fig. 3, if the critical triggering temperature is set as 35°C, then all the CPP dates can be screened.

B. Selection of CPP Time Intervals

According to the load data, the CPLs only appear in 5 days of the year, that is, July 22 to 23 and August 4 to 6. The frequency distribution of the appearances of CPLs on each time interval is shown in Fig. 4.

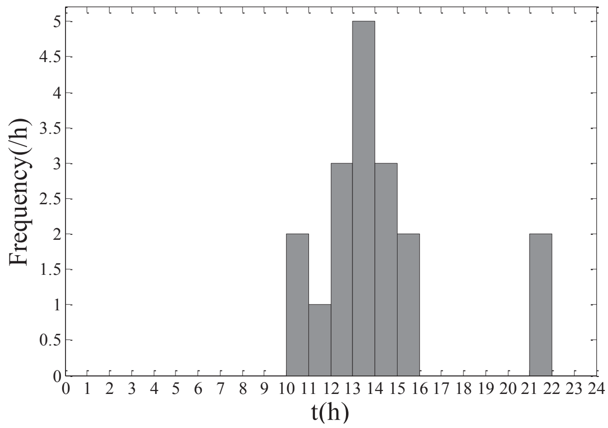

Fig. 4 Frequency distribution of the appearances of CPLs on each time interval of all CPP day.

So the proper selection of CPP time intervals is 10:00-16:00 and 21:00-22:00.

C. Estimation of Load-price Elasticity Distribution

The peak-flat-valley pricing policy has been implemented in this area for a long time. The time intervals of each electricity price is shown below.

Peak Pricing: 9:00-12:00, 19:00-22:00

Flat Pricing: 12:00-19:00, 22:00-24:00

Valley Pricing: 0:00-8:00

For CPP target customers, the peak price is 1 yuan, the flat price is 0.6 yuan, and the valley price is 0.3 yuan.

There are 6 intersections of electricity price intervals in a day, i.e., endpoints at 0, 8, 12, 19, 22, and 24 o'clock as shown in Fig. 5.

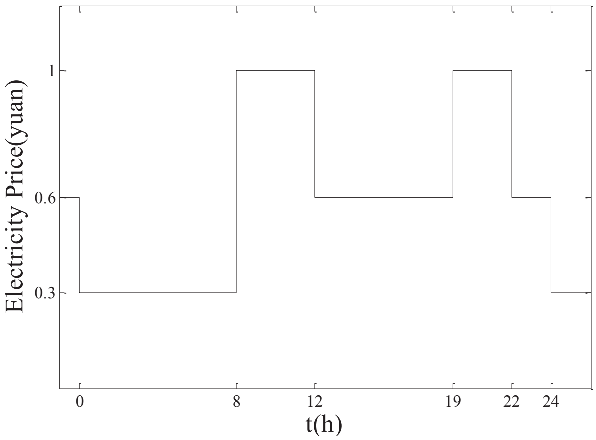

Fig. 5 Daily electricity price distribution.

Use the absolute load differential one hour before and after each endpoint divided by the absolute electricity price differential as the endpoint elasticity. So six endpoint elasticities can be obtained. The load-price elasticity for each electricity price interval is calculated as the average of two endpoint elasticities at the interval. Then the load-price elasticity distribution of each day can be estimated. As an example, Fig. 6 displays the load elasticity of one day.

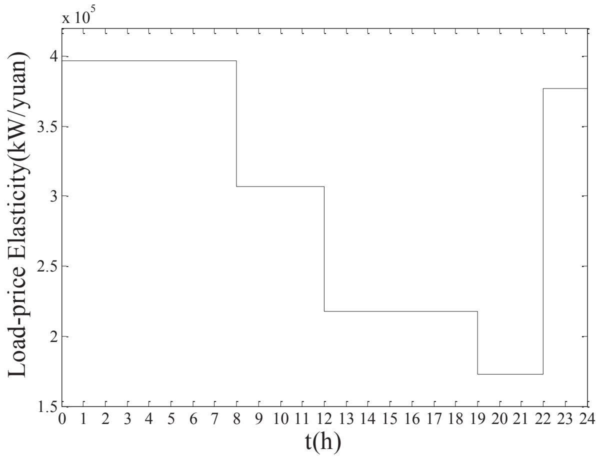

Fig. 6 Load-price elasticity distribution of one day.

D. Pricing Optimization for Fee Balance Mode

Based on the load data and the load response model, the pricing optimization can be conducted. Suppose the CPP and VP load transfer factor are both 10%, and put Δ_1 and Δ_2 in (6) and (7) as 0.5 yuan and 0.2 yuan respectively. The optimal pricing strategy is achieved by employing the fmincon function of MATLAB; that is, dp_1 is set as 0.0310 yuan and dp_2 is set as 0.2000 yuan. The maximum daily load of CPP days is cut by 1.10%.

E. Pricing Optimization for Fee Increase Mode

Put Δ in (9) as 1% of the total electricity fees collected on all CPP days before CPP implementation. All increased fees are used for IL purchases at CPP time intervals. Suppose that there are 10 ILs available, and the details are shown in TABLE I. Other parameters are set identical to those in fee balance mode.

TABLE I Interruptible load parameters.*

k	pi (yuan/kWh)	$PI^k_{\min}$ (MW)	$PI^k_{\max}$ (MW)	$S^{k\ \mathrm{on}}_{\min}$ (h)	$S^{k\ \mathrm{off}}_{\min}$ (h)
1	0.7	6	14	1	2
2	0.9	5.8	27.5	1	2
3	0.85	7	21	1	2
4	1.2	5.5	34	1	2
5	0.9	10	47	2	0
6	1.1	12	27	2	1
7	1.3	11	32	0	2
8	1.45	14	30	3	1
9	1.35	20	25	1	3
10	0.95	17	32	2	1

*The table headers correspond to parameters in (10) – (13).

This problem belongs to nonlinear mixed-integer programming optimization. Use the sectionalized method to linearize the problem, and then the MATLAB-based CPLEX toolbox is employed to achieve the optimal results: dp_1 is set as 0.0510 yuan and dp_2 is set as 0.2000 yuan; the IL purchase strategy on the 5 CPP days is shown in Fig. 7 and Fig. 8. The maximum daily load of CPP days is cut by 5.12%. Therefore, the fee increase mode surpasses the fee balance mode.

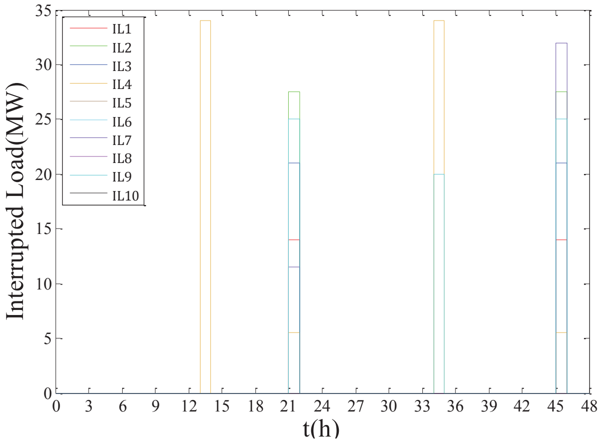

Fig. 7 The IL purchase strategy from July 22 to 23.

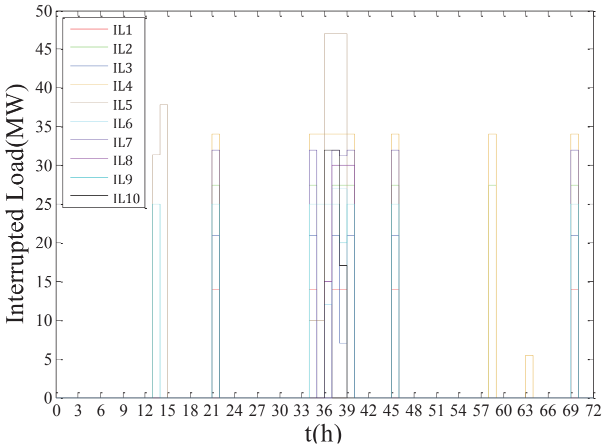

Fig.8 The IL purchase strategy from August 4 to 6.

VI. CONCLUSION

This paper analyzes the optimization of CPP policy. Temperature triggering is employed to screen the CPP dates, and the statistical method is used for the CPP time interval selection. Then the pricing optimization on CPP days is conducted based on the load response model, considering the fee balance mode and the fee increase mode. The results indicate that the fee increase mode surpasses the fee balance mode.

However, in this paper, the CPP and VP load transfer factor are assumed to be certain values. So further efforts should be put on the determination and sensitivity analysis of the two parameters.

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