Flexibility Optimal Dispatching for Power System Considering Demand Response

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Abstract. With the increasing penetration of renewable energy sources such as wind and solar power, higher requirements of flexible supply ability for power systems are put forward. In this context, an optimal dispatching method considering two types of demand response is proposed to improve power system flexibility. On the demand side, both the time-of-use (TOU) price and interruptible load are used to guide consumers to actively optimize the load curve, so as to relieve the pressure of the flexible supply of conventional units on the supply side. The demand response model consisting of TOU price and interruptible load is built. Then, taking the minimum cost as the objective function, the optimization model for power system dispatching is solved. Finally, the modified IEEE 30 bus system is taken as a case study. The results show that the consideration of two-type demand response in the optimal dispatching can improve the flexibility while ensuring economy, which verifies the effectiveness of the proposed method.

1. Introduction

The concept of demand-side management (DSM) was first proposed by Electric Power Research Institute (EPRI) in 1986 [1], and then it was gradually recognized and widely adopted by various countries [2]-[6]. Demand response, to put it simply, is to guide electricity power users to change the original consumption mode and structure using electricity price or incentive compensation, to transfer or reduce their electricity load in different periods, to adjust and optimize the load curve [7]. To alleviate the contradiction between supply and demand and improve the economy of power system operation, the demand side is taken as the alternative resource of the supply side to meet the power system flexibility requirement.

Demand response can be divided into two types according to different response mechanisms. The first type is price-based demand response [8], [9]. This type refers to guiding power users to change the original model of electricity consumption by changing the price of electricity, to realize the transfer of load between different periods. The second type is incentive-based demand response [10]-[12]. This type refers to that power supply companies directly use incentives to guide users to reduce load when the power supply is insufficient. Users participating in this type of project can obtain corresponding compensation fees according to the prior agreement. The work in [13] analysis the effect that the market structure can have on the elasticity of the electricity demand. Based on this, a computable equilibrium model is established to estimate the time-of-use (TOU) price [14]. Then a more simple and accurate method is obtained based on the original ones.
Under the high rate of renewable energy penetration in the future, system optimization should be emphasized to improve the renewable energy consumption of the power system through demand response. A stochastic planning unit combination model including wind power system is established [15], which considers demand response resources. The case study shows that the wind power consumption of the system can be improved. The optimization model of system consumption of wind power under the background of TOU is established [16], which verifies that TOU is an effective means to promote the consumption of wind power. The work in [17] introduced interruptible load into the power system, established a joint dispatching model of wind power and thermal power, and analysed the impact of interruptible load on system operation economy.

As the penetration rate of renewable energy increases, the flexibility requirements of the power system increase. Large-scale renewable energy is faced with the problem of consumption, and it is difficult to meet the flexibility requirement depending on traditional dispatching methods. Therefore, an optimal scheduling method considering demand response is proposed in this paper, which can improve the renewable energy consumption of the power system while ensuring the economy.

The rest of this paper is organized as follows. Section 2 gives the models of TOU price and interruptible load. And Section 3 gives the optimal dispatching model of the power system considering demand response. Section 4 presents the case studies, which including wind power, photovoltaic (PV), energy storage, and conventional units, and the conclusion is followed in Section 5.

2. Demand response model

2.1. TOU price model

When the TOU price is adopted, there is a substitution relationship between the electricity prices of adjacent periods. To describe the demand elasticity of peak-valley electricity price, we use the self-elasticity coefficient and cross-elasticity coefficient to express:

$$\varepsilon_{ii} = \frac{\Delta P_i / P_i}{\Delta Q_i / Q_i}, \quad \varepsilon_{ij} = \frac{\Delta P_i / P_i}{\Delta Q_j / Q_j},$$

where $\varepsilon_{ii}$ and $\varepsilon_{ij}$ are the self-elasticity coefficient and cross-elasticity coefficient; $i$ and $j$ represent period $i$ and period $j$; $P$ and $Q$ are the electricity consumption and price in the period $i$ before the implementation of TOU price; $\Delta P_i$ and $\Delta Q_i$ are the changes of electricity consumption and price in period $i$ after the implementation of TOU price.

Based on the self-elasticity coefficient and cross elasticity coefficient, the load curve after considering the TOU price can be obtained.

$$P_{iL} = P_i \left(1 + \varepsilon_{ii} \frac{\Delta Q_i}{Q_i} + \sum_{j \neq i} \varepsilon_{ij} \frac{\Delta Q_j}{Q_j}\right)$$

where $T$ is the total number of periods in the scheduling cycle; $P_{iL}$ is the actual load demand in period $i$ after considering TOU price.

After the implementation of TOU price, the difference in electricity sales income is:

$$C^{TOU} = \sum_{i=1}^{T} \left(P_i Q_i - P_{iL} (Q_i + \Delta Q_i)\right)$$

The constraints are as follows.

- Constant total electricity consumption constraint

$$P_i + P_p + P_g = P'_i + P'_p + P'_g$$

where $P_i$, $P_p$, $P_g$, $P'_i$, $P'_p$, and $P'_g$ are the total electricity consumption in peak, valley, and flat periods before and after the implementation of TOU price.
• Price ceiling and floor constraints
\[ Q_i \leq Q_g \leq Q_p \leq Q_i \leq Q_i \]  \hspace{0.5cm} (5)
where \( Q_h \) and \( Q_i \) are the electricity price ceiling and floor.

• Peak-valley price difference constraint
\[ Q_i \geq r_{lg} Q_g, \quad Q_{pg} \geq r_{pg} Q_g \]  \hspace{0.5cm} (6)
where \( r_{lg} \) is the minimum peak-valley electricity price ratio; \( r_{pg} \) is the minimum flat-valley electricity price ratio.

• Power supply company interest not loss constraint
\[ M \geq M_0, \quad M = \sum_{i=1}^{N_l} P_{i}^{IL} (Q_i + \Delta Q_i), \quad M_0 = \sum_{i=1}^{N_l} P_i Q_i \]  \hspace{0.5cm} (7)
where \( M \) is the electricity sale income after the implementation of TOU price; \( M_0 \) is the electricity sale income before the implementation of TOU electricity price.

2.2. Interruptible load model

When the system cannot meet the peak load regulation requirements, partial or all interruptible loads can be interrupted and some economic compensation can be given to the users, to maintain the balance between supply and demand of active power of the system. The cost function of interruptible loads participating in scheduling is as follows.
\[ C_{IL} = \sum_{i=1}^{T} \left( \rho_{il} P_{i}^{IL} \right) \]  \hspace{0.5cm} (8)
where \( \rho_{il} \) is the compensation price of interruptible load; \( P_{i}^{IL} \) is the total amount of interruptible loads participating in scheduling in period \( t \).

The constraints are as follows.

• Interruptible load interrupt quantity constraint
\[ 0 \leq P_{i}^{IL} \leq P_{i}^{IL,\max} \]  \hspace{0.5cm} (9)
where \( P_{i}^{IL,\max} \) is the maximum interrupt amount of the interruptible load.

• Maximum interrupt duration and minimum call interval constraints
\[ \sum_{i=1}^{T} U_{i}^{IP} \leq T_{on,\max}, \quad \left( U_{i}^{IP} - U_{i-1}^{IP} \right) \left( T_{no} - T_{off,\min} \right) \geq 0 \]  \hspace{0.5cm} (10)
where \( U_{i}^{IP} \) is the state variable of the interruptible load in the period \( t \); \( U_{i}^{IP} \) = 1 means called; \( U_{i}^{IP} = 0 \) means not called; \( T_{on,\max} \) is the maximum interruption duration of the interruptible load; \( T_{no} \) is the continuous uninvoked time of interruptible load; \( T_{off,\min} \) is the minimum call interval of the interruptible load.

• Total call time constraints within the schedule cycle
\[ \sum_{i=1}^{T} U_{i}^{IP} \leq T_{sum,\max} \]  \hspace{0.5cm} (11)
where \( T_{sum,\max} \) is the total time that the interruptible load is allowed to be invoked during the scheduling cycle.

• Interruptible load interrupt number constraint
\[ \sum_{i=1}^{T} U_{i}^{IP} \left( 1 - U_{i-1}^{IP} \right) \leq N_{ip} \]  \hspace{0.5cm} (12)
where \( N_{ip} \) is the maximum number of interruptions of interruptible load within the scheduling cycle.
3. Optimal scheduling model of power system

3.1. Objective function

The objective function of the optimal scheduling model is to minimize the cost. It includes coal consumption cost, unit start-up and shutdown costs, charge and discharge costs of energy storage device, operating cost of wind and PV power, penalty cost of abandoning wind and PV power, income difference after implementation of TOU price, and compensation cost of the interruptible load.

$$\min C = \sum_{t=1}^{T} \left[ \sum_{i=1}^{N_C} \left( C_{i,t}^f \left( P_{i,t}^f \right) + C_{i,t}^{up} + C_{i,t}^{dn} \right) + \sum_{k=1}^{N_R} \left( C_{k,t}^{dc} P_{k,t}^{dc} + C_{k,t}^{ch} P_{k,t}^{ch} \right) + \sum_{j=1}^{N_R} \left( C_{j,t}^r P_{j,t}^r + \rho_j \left( P_{j,t}^{r,\max} - P_{j,t}^r \right) \right) \right] + C^{TOU} + C^{IL}$$

(13)

where $N_C$, $N_R$, and $N_R$ are the number of conventional units, energy storage units and renewable energy units; $C_{i,t}$, $C_{i,t}^{up}$, and $C_{i,t}^{dn}$ are the coal consumption cost, start-up cost and shutdown cost of conventional unit $i$ in period $t$; $P_{i,t}^f$ is the real output of conventional unit $i$ in period $t$; $C_{k,t}^{ch}$ and $C_{k,t}^{dc}$ are the charging and discharging costs of the energy storage device $k$ in period $t$; $P_{k,t}^{ch}$ and $P_{k,t}^{dc}$ are the charging and discharging power of the energy storage system $k$ in period $t$; $C_{j,t}^r$ is the operating cost of renewable energy units $j$; $P_{j,t}^r$ and $P_{j,t}^{r,\max}$ are the real output and prediction output of renewable energy units $j$ in period $t$. $\rho_j$ is the penalty cost of abandoning wind and PV power.

The coal consumption cost of the conventional unit can be expressed as a quadratic function.

$$C_{i,t}^f \left( P_{i,t}^f \right) = a_i \left( P_{i,t}^f \right)^2 + b_i P_{i,t}^f + c_i$$

(14)

where $a_i$, $b_i$, and $c_i$ are the coal consumption coefficient of conventional unit $i$.

3.2. Constraint Condition

- Power balance constraint

$$\sum_{i=1}^{N_C} P_{i,t}^f + \sum_{j=1}^{N_R} P_{j,t}^r + \sum_{k=1}^{N_R} \left( P_{k,t}^{dc} - P_{k,t}^{ch} \right) + P_{i,t}^{IL} = P_{i,t}^{PL}$$

(15)

- Hot standby constraint

$$\sum_{i=1}^{N_C} \left( u_{i,t} P_{i,t}^{\max} - P_{i,t}^f \right) \geq \eta P_{i,t}^{PL}$$

(16)

where $u_{i,t}$ is the operating state variable of conventional unit $i$ in period $t$ (1 for operating and 0 otherwise); $P_{i,t}^{\max}$ is the maximum output of conventional unit $i$; $\eta$ is the hot standby coefficient.

- Unit output and ramp constraints

$$u_{i,t} P_{i,t}^{\min} \leq P_{i,t}^f \leq u_{i,t} P_{i,t}^{\max}, -R_{i,t}^{\min} \leq P_{i,t}^f - P_{i,t-1} \leq R_{i,t}^{\max}$$

(17)

where $P_{i,t}^{\min}$ is the minimum output of conventional unit $i$; $R_{i,t}^{\max}$ and $R_{i,t}^{\max}$ are the ramp rate of conventional unit $i$.

- Startup/shutdown cost constraints

$$C_{i,t}^{up} \geq H_i \left( u_{i,t} - u_{i,t-1} \right), C_{i,t}^{up} \geq 0, C_{i,t}^{dc} \geq J_i \left( u_{i,t} - u_{i,t-1} \right), C_{i,t}^{dc} \geq 0$$

(18)

where $H_i$ and $J_i$ are the single startup cost and shutdown cost of conventional unit $i$.

- Startup/shutdown time constraints

$$\sum_{t=1}^{T} \left( 1 - u_{i,t} \right) \geq T_{dn} \left( u_{i,t-1} - u_{i,t} \right), \sum_{t=1}^{T} u_{i,t} \geq T_{up} \left( u_{i,t} - u_{i,t-1} \right)$$

(19)

where $T_{dn}$ and $T_{up}$ are the minimum shutdown and start-up times of conventional unit $i$. 


• Energy storage devices power constraints

\[ 0 \leq P_{k,t}^{ch} \leq P_{k,t}^{ch,max} U_{k,t}^{ch}, \quad 0 \leq P_{k,t}^{dc} \leq P_{k,t}^{dc,max} U_{k,t}^{dc}, \quad U_{k,t}^{ch} + U_{k,t}^{dc} \leq 1 \]  
where \( U_{k,t}^{ch} \) and \( U_{k,t}^{dc} \) are the charging decision variable (1 for charging and 0 otherwise) and discharging decision variable (1 for discharging and 0 otherwise) of energy storage device \( k \) in period \( t \).

• Energy storage devices charge capacity constraints

\[ E_{k,t}^{min} \leq E_{k,t}^{max}, \quad E_{k,t=0} = E_{k,t-T}, \quad E_{k,t} = (1 - \delta_k) \cdot E_{k,t-1} + \eta_k^{ch} P_{k,t}^{ch} \Delta T - \frac{1}{\eta_k^{dc}} P_{k,t}^{dc} \Delta T \]  
where \( E_{k,t} \) is the charge capacity of the energy storage device \( k \) at time \( t \); \( E_{k,t}^{max} \) and \( E_{k,t}^{min} \) are the maximum and minimum charged capacities of the energy storage device \( k \); \( \delta_k \) is the self-discharge coefficient of the energy storage device \( k \); \( \eta_k^{ch} \) and \( \eta_k^{dc} \) are the energy conversion efficiency in the charging and discharging process of the energy storage device \( k \).

3.3. Solving Method

The coal consumption cost is a quadratic function, which needs piecewise linearization.

\[ C_{ij} (P_{i,t,s}, u_{i,t}) = \sum_{k=1}^{m} k_{i,s} P_{i,t,s}^{G} + u_{i,t} C_{0,i} \]  
where \( C_{0,i} = a_i \left( P_{i,t,s}^{G,min} \right)^2 + b_i P_{i,t,s}^{G,min} + c_i \); \( 0 \leq P_{i,t,s}^{G,min} \leq \frac{P_{i,t,s}^{G,max} - P_{i,t,s}^{G,min}}{m} ; \quad P_{i,t,s}^{G} = \sum_{i=1}^{m} P_{i,t,s}^{G} + P_{i,t,s}^{G,min} ; \quad m \) is the number of the piecewise; \( k_{i,s} \) is the slope of each piecewise of the coal consumption function after piecewise linearization; \( C_{0,i} \) is the coal consumption cost when the unit operates with minimum output; \( P_{i,t,s}^{G} \) is the output of each piecewise of unit \( i \).

After the coal consumption cost is linearized, the proposed model is transformed into a mixed integer linear programming (MILP) model, which can be solved by calling the CPLEX solver.

4. Case study

4.1. Case introduction

The modified IEEE 30 bus system is taken as a case study, as shown in figure 1. The unit parameters are shown in table 1. Selecting 24 hours of a typical day as the scheduling period, the predicted output curves of wind and PV power within this day are shown in figure 2.

![Figure 1. The modified IEEE 30 bus system.](image1)

![Figure 2. The prediction of wind and PV power.](image2)
### Table 1. The unit parameters

| Unit | $P_i^{\text{min}}$(MW) | $P_i^{\text{max}}$(MW) | $a_i$ ($) | $b_i$ ($) | $c_i$ ($) | $R_{g}^{\text{dan/up}}$ (MW/h) | $T_{up}$ (h) | $T_{dn}$ (h) |
|------|----------------|----------------|--------|--------|--------|----------------|--------|--------|
| 1    | 155            | 78             | 0.00463 | 10.6940 | 142.7348 | 78               | 5      | 5      |
| 2    | 100            | 50             | 0.00712 | 19.1000 | 230.0000 | 50               | 4      | 4      |
| 3    | 76             | 38             | 0.00876 | 13.3272 | 81.1364 | 38               | 3      | 3      |
| 4    | 76             | 38             | 0.00895 | 13.3538 | 81.2980 | 38               | 3      | 3      |
| 5    | 100            | 50             | 0.00612 | 18.1000 | 218.3350 | 50               | 4      | 4      |
| 6    | 50             | 25             | 0.01036 | 19.3272 | 87.1364 | 25               | 3      | 3      |

#### 4.2. Simulation results and analysis

When demand response is not considered, the optimal scheduling results are shown in figure 3. The total operating cost is $208,316, in which the amount of abandoned wind and PV power is shown in figure 4. When considering demand response, the load response curve and the original curve are shown in figure 5. In this case, the optimal scheduling results are shown in figure 6. The total operating cost is $208,119, and there is no amount of abandoned wind and PV power. Comparative analysis of figure 3 and figure 6 can draw the following conclusions.

- The amount of abandoned wind and PV power can be reduced by considering the demand response. This can promote the consumption of renewable energy.
- After considering the demand response, the fluctuation of output of conventional units becomes smaller, which is beneficial to the operation and maintenance of conventional units.
- After considering the demand response, the charging and discharging times of the energy storage device are reduced, which is conducive to prolonging its service life.
5. Conclusion
The increasing penetration of renewable energy sources has brought great challenges to power balance, which requires improving the flexible supply capacity of the power system. Based on two kinds of demand response models, i.e., TOU price-interruptible load and time of use price load-interruptible load, an optimal dispatching model of power systems considering demand response is established. Taking the modified IEEE 30-bus system as a case study, the simulation results are compared and analyzed. It can be concluded that considering the two-type demand response can improve the flexibility of the power system while ensuring the economy.

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