Joint planning of distribution network and substation considering the effect of electric heating load

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Abstract. A joint planning method for distribution network and substation considering the influence of electric heating load is proposed based on LCC in this paper. A multi-state model of electric heating load level is obtained by state sampling combination of ordinary load and electric heating load according to Monte Carlo method (MCS). Taking line investment cost, operation and maintenance cost, adjustable capacity transformer investment cost, operation cost, network loss cost and user outage loss cost as objective functions, a joint planning model of distribution network and substation considering the influence of electric heating load is established. The multi-objective optimization problem is transformed into a single-objective optimization problem by weighting, and solved by genetic algorithm with mixed chromosome coding. The simulation results show the effectiveness of the proposed method.

1. Introduction
With the pressure of environmental protection, especially the widespread fog and haze in the northern region in winter, The State Council promulgated the action plan for the air pollution control([2013] 37), the Ministry of Environmental Protection and other four ministries issued the work programme for the prevention and control of air pollution in Beijing-Tianjin-Hebei and its surrounding areas in 2017 ([2017] 29), which explicitly proposed the implementation of large-scale electric heating in the northern region, while the investment of power grids amounts to tens of billions of yuan. Thus, adapting to large scale electric heating load access has become an important issue faced by power grid enterprises.

Electric heating load has obvious seasonal characteristics. In addition, the government promotes clean electric heating throughout the village. The load simultaneous rate in the platform area is higher, and the load peak-valley difference is larger. Traditional planning based on maximum operating conditions is obviously less economic. The transformer is operated under light load for a long time, the loss of the station area is large, and the utilization efficiency of the equipment is low. In view of this problem, some scholars solve the distribution network planning model based on chance constrained programming. However, it implies[1] or permits[2] [3] the constraints of distribution network operation does not completely meet the requirements. At present, in order to cope with the effect of
electric heating load access distribution network, some areas have been equipped with capacity-regulating transformers in practical engineering. When the heating season load increases, transformers automatically adjust to high-grade operation. When the station load decreases, transformers automatically adjust to low-grade operation, and the loss is low in long-term operation. Thus, the application of capacity-regulating transformer in distribution network engineering can better balance the economy and reliability of the coordinated planning scheme. However, there are few in-depth studies on the planning of distribution network with large-scale electric heating load.

Aiming at the deficiency of current research, this paper considers the investment and operation cost of adjustable capacity transformer, considers the joint planning of grid and substation from the point of view of LCC, proposes a distribution network planning model considering the effect of electric heating load, and uses genetic algorithm to solve the model. Numerical examples verify the effectiveness and correctness of the proposed method.

2. Multi state model of electric heating load

In the planning period, normal distribution is used to describe the uncertainty of normal load. Its probability density function is

\[
f(P) = \frac{1}{\sqrt{2\pi}\sigma} \exp\left(-\frac{(P-\mu)^2}{2\sigma^2}\right)
\]

where \(\mu\) is mathematical expectation, \(\sigma\) is standard deviation.

Electric heating load is seasonal load. The typical daily load is used to simulate the discrete operation state, and the operation state probability is determined according to the heating season time. The probability of each state of load is the ratio of the duration of heating season to one year. In this paper, the Monte Carlo method (MCS) [10] is used to sample the normal load and the electric heating load, and a sampling \(N_S \times M\) dimensional matrix reflecting the multi-state of the normal load and the electric heating load is obtained, where \(M\) is the number of random variables sampled, and \(N_S\) is the sampling frequency. From this, a multi state model of electric heating load level \(i\) is obtained.

3. Distribution network planning model considering the effect of electric heating load

3.1. Objective Function

After determining the location of electric heating load, next we determine the joint optimization planning of grid and distribution transformer, which satisfies the safety and reliability of power supply, as well as the minimum annual investment, operation cost, distribution transformer investment cost, operation cost, network loss cost and user outage risk cost. Therefore, this paper establishes a multi-objective optimization programming model with six sub-objectives of line investment cost \(f_1\), operation and maintenance cost \(f_2\), distribution transformer investment cost \(f_3\), distribution transformer operation cost \(f_4\), network loss expectancy \(f_5\) and user outage loss expectancy \(f_6\). The objective function is

\[
\min F = \omega_1 f_1 + \omega_2 f_2 + \omega_3 f_3 + \omega_4 f_4 + \omega_5 f_5 + \omega_6 f_6
\]

1) Annual cost of line investment

\[
C_{\text{invest}} = F_{L,\text{invest}} \frac{r(1+r)^n}{1+r^n} - 1
\]

where \(C_{\text{invest}}\) refers to the cost of investment; \(F_{L,\text{invest}}\) refers to the initial investment cost of the line; \(r\) refers to the discount rate.

2) Annual operation and maintenance cost of line

\[
C_m = \alpha C_{\text{invest}}
\]

where \(C_m\) is the annual operation and maintenance cost of the line, \(\alpha\) is the conversion coefficient of annual operation cost.

3) Annual line cost expectation
where $\overline{C}_{L,\text{loss}}$ refers to the expected network loss cost, $\tau_{\text{max}}$ refers to the maximum load loss hours, $C_{\text{pu}}$ refers to the purchase cost to the higher power grid (yuan / kWh), $\Delta P_k$ refers to the network power loss (kW) under the operation state $k$, $N_S$ refers to the operation state number of distribution system.

4) Annual cost of adjustable capacity transformer investment

$$C_{\text{invest}} = F_{T,\text{invest}} \times r(1+r)^n \frac{r}{(1+r)^n-1}$$

where $C_{\text{invest}}$ is the cost of investment; $F_{T,\text{invest}}$ is the initial investment cost of the transformer; $r$ is the discount rate.

5) Expectation of annual consumption cost of adjustable capacity transformer

$$\overline{C}_{T,\text{loss}} = C_{\text{pu}} \sum_{k=1}^{N_S} \left( T_k \Delta P_k + T_0 \Delta P_0 \right) / N_S$$

In Equation (8), it is assumed that the transformer can be automatically adjusted to the minimum loss capacity under different operation conditions. $\overline{C}_{T,\text{loss}}$ is the expectation of consumption cost of adjustable capacity transformer, $T_k$ is the running time of distribution transformer in running state $k$. $C_{\text{pu}}$ is the purchase cost to the higher power grid (yuan / kWh), $\Delta P_k$ is the active power loss (kW) of the adjustable capacity transformer under the running state $k$ and the capacity rating. $\Delta P_0$ is the reactive power loss (kW) of the adjustable capacity transformer under the running state $k$ and the capacity rating. $N_S$ is the operation state number of distribution system.

3.2. Constraint Condition

Combining with the technical criteria for grid operation and planning, the grid planning satisfies the constraints of power balance, node voltage, radial network, branch power flow and reliability.

1) Power balance constraint

$$P_i = U_i \sum_{j=1}^{n} U_j (G_{ij} \cos \theta_{ij} + B_{ij} \sin \theta_{ij})$$

$$Q_i = U_i \sum_{j=1}^{n} U_j (G_{ij} \sin \theta_{ij} - B_{ij} \cos \theta_{ij})$$

where $P_i$ and $Q_i$ are the active and reactive power injected into node $i$; $U_i$ and $U_j$ are the voltage amplitudes of node $i$ and $j$ respectively; $G_{ij}$ and $B_{ij}$ are the conductance and admittance of branch $ij$ respectively; and $\theta_{ij}$ is the angle difference between node $i$ and $j$.

2) Node voltage constraint

$$U_i^\text{max} \leq U_i(x,k) \leq U_i^\text{min} \quad i \in \Omega_{\text{node}}$$

where $U_i(x,k)$ is the voltage value of node $i$ under state $k$; $U_i^\text{min}$ and $U_i^\text{max}$ are the upper and lower limits of branch $i$; and $\Omega_{\text{node}}$ is the set of system nodes.

3) Line current constraint

$$\overline{I}(i,k) \leq I_i^\text{max} \quad i \in \Omega_{\text{line}}$$

where $\overline{I}(i,k)$ is the current of branch $i$ under state $k$, and $I_i^\text{max}$ is the maximum allowable current of branch $i$. $\Omega_{\text{line}}$ is a collection of system lines.

4) Reliability constraint

$$R_{\text{ASA}I} \geq \overline{R}_{\text{min}}$$

$$R_{\text{ASA}I} = \frac{R_{\text{total}} \times 8760 - \sum_{j=1}^{N} U_j N_j}{R_{\text{total}} \times 8760}$$
where $R_{\text{ASAI}}$ is the average power supply availability, $N_{\text{total}}$ is the total number of users in the system, 8760 is the number of hours per year, $U_j$ is the average annual outage time of affected users when the fault occurs, and $N_j$ is the number of users affected during failure.

5) Radial structure constraint
The planned network plan needs to meet the radiated power supply requirements.

4. Solution of distribution network planning model considering the influence of electric heating load based on LCC
The process of solving the model is as follows:

1) Input information such as grid frame, distribution transformer and initial parameters of genetic algorithm.

2) By using Monte Carlo method (MCS) to sample $NS$ times of normal load and electric heating load, a multi-state load model is established to reflect the complex operating conditions of distribution network.

3) Initialize the population and set the number of iterations $G_0=1$;

4) Calculate the objective function value of each planning plan. Verify the $NS$ running status of the plan in turn. Using forward and backward substitution algorithm for power flow calculation. If the constraint condition is violated, the objective function value is assigned a penalty value. Otherwise, we can get the expected value of the objective function of the scheme.

5) Genetic operations of selection, crossover and mutation are needed to generate new populations.

6) Determines whether iteration termination condition is satisfied., if it is satisfied, the result is output, otherwise, turn to step 4.

5. Case study
5.1. Parameters
The typical daily load curve of electric heating load is shown in Figure 1. The planning area [5] is shown in Figure 2. The network consists of 42 lines to be built. The power supply point is 1 (35/10.5 kV substation) to 24 load nodes (10/0.4 kV substation) and the voltage level is 10 kV.

For branch data and load node initial power expectation, see literature [5]; variance is 10-4, planning scheme life is 10 years. the discount rate $r$ is 12.5%, the annual operation and maintenance cost coefficient is 0.155, and the $R_{\text{ASAI}}$ is greater than 99.9% under the reliability constraint. The allowable fluctuation range of node voltage is ±7%; the purchasing price is 0.394 yuan / (kW h) to the higher power grid; the heating season is 6 months; the weight of each objective function is set to 1. Electric heating load is connected to nodes 7, 9, 11, 17, 18, 23.. The unit power loss cost [6] is shown in Table 1, and the transformer parameters is shown in Table 2.

![Figure 1: Typical daily load curve of electric heating load](image1)

![Figure 2: Graph of available supply routes of 25 nodes](image2)
Table 1. Typical value of unit outage costs

| Importance of load | Outage cost (¥/kWh) |
|--------------------|---------------------|
| 1                  | 5.292               |
| 2                  | 51.045              |
| 3                  | 104.363             |

Table 2. Transformer parameters

| Transformer type | Construction cost (ten thousand yuan) | No-load loss (W) | No-load current (%) | Load loss (W) |
|-----------------|----------------------------------------|------------------|---------------------|---------------|
| S11 (160/50)    | 3                                      | 280              | 0.7                 | 2310          |
| S11 (315/100)   | 4.5                                    | 480              | 0.55                | 3830          |
| S11 (400/125)   | 6                                      | 570              | 0.5                 | 4520          |
| S11 (160)       | 2                                      | 280              | 1.5                 | 2310          |
| S11 (315)       | 3                                      | 480              | 1.4                 | 3830          |
| S11 (400)       | 4                                      | 570              | 1.3                 | 4520          |

5.2. Calculations and Analysis

The genetic algorithm was used to solve the programming model. The population size was 200, the number of iterations was 50, the crossover probability $P_c = 0.9$ and the genetic variation rate $P_m = 0.02$ were set. In this paper, two methods are used to calculate and compare the results. Method 1: Considering the effect of electric heating load, capacitance-regulating transformer is used to supply electric heating load in actual planning; Method 2: Selecting non-capacitance-regulating transformer plan according to the maximum operating condition of the system without considering the effect of electric heating load.

The results of grid and substation planning are shown in tables 3 and 4.

Table 3. Results of planning schemes

| Cost (ten thousand yuan) | Method 1 (Plan A) | Method 2 (Plan B) |
|--------------------------|-------------------|-------------------|
| Total cost               | 138.14            | 142.13            |
| Annual investment cost of line | 74.74             | 75.58             |
| Annual operation and maintenance cost of line | 11.58             | 11.71             |
| Annual investment cost of transformer | 4.06              | 2.25              |
| Annual operation cost of transformer | 2.50              | 4.62              |
| Network loss expectation cost | 11.79             | 12.53             |
| Customer outage cost expectation | 33.46             | 35.44             |
| Reliability index         | 99.972%           | 99.972%           |

Table 4. The corresponding network routes of the planning schemes

| planning scheme | network planning for distribution network | Transformer planning for distribution network |
|-----------------|-------------------------------------------|-----------------------------------------------|
| Plan A          | 2,5,7,9,10,11,13,21,22,23,24,26,28,29,32,33,34,35,36,37,39,40,41,42 | S11 (315/100), S11 (315/100), S11 (315/100) |
| Plan B          | 2,6,9,12,13,16,21,22,23,24,26,28,29,30,31,32,33,34,35,36,37,39,40,41 | S11 (160), S11 (315), S11 (160), S11 (160), S11 (160) |

When using the proposed algorithm, the planning scheme is plan A, and the total cost of the plan A is 138.14 ten thousand yuan. At the same time, the result of traditional algorithm planning is B, the
The total cost of the plan B is 142.13 ten thousand yuan. According to table 4, the substation planning plan is very different. The initial investment cost of substation in plan A is 4.06 ten thousand yuan, higher than that in plan B, while the operation cost of substation in plan A is 2.5 ten thousand yuan, lower than that in plan B. Therefore, the plan A is reasonable. Therefore, the whole life cycle cost of substation has great influence on the planning results.

The route planning plan is shown in Figure 3.

![Figure 3. Graph of the planning result of network](image)

6. Conclusions

A joint planning method of distribution network and substation is proposed in this paper, considering the influence of large-scale electric heating load on distribution network planning and the energy-saving characteristics of capacity-regulating transformer. It can better deal with the impact of peak and valley load difference on distribution network planning and reduce the total investment and operation cost of power grid enterprises. It is of great significance for the current power grid enterprises to invest in electric heating load supporting power grid construction.

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