COMPARATIVE ANALYSIS OF METHODS FOR ESTIMATING ELECTRICITY LOSSES IN PROBLEMS OF OPERATIONAL OPTIMIZATION OF POWER SYSTEM MODES

V.Kh. Nasibov R.R. Alizade E.J. Isgenderov

•

Azerbaijan Scientific-Research and Design-Prospecting Power Engineering Institute
nvaleh@mail.ru , rena_alizade@mail.ru , iskenderelvin@gmail.com

Abstract

The distribution of unscheduled capacity corresponding to the difference between current and forecast values should be carried out according to the criterion of minimum costs for the units involved to cover this capacity. In operational management, the optimization of power distribution is the process of adjusting the regime for active power, obtained during its short-term planning and optimization. Some of the optimization parameters, such as the relative increase in energy consumption and a measure of the efficiency of the use of water resources, can be determined in the optimization of short-term regimes and used in the optimization of operational regimes. Other parameters included in the operational optimization equation are either calculated during operational control using telemetered parameters, or are set. During the operational optimization of the regime, unscheduled power between stations must be distributed in such a way as to ensure the same relative increases in energy consumption at power plant units, taking into account the relative increases in power losses in the network from the power of these stations. The article considers a comparison of two methods for the operational assessment of the relative increments of power losses for the tasks of operational optimization of the mode by active power.

Keywords: Knowledge Assessment, Training, Fuzzy Knowledge Base

I. Introduction

Operational optimization of load distribution in a mixed power system has a number of features, both in terms of the sequence of algorithmic constructions, and in terms of software implementation of the developed algorithms. The possible participation of HPPs in covering unplanned capacity, corresponding to the difference between current and forecast values, makes it necessary to conduct operational optimization of the regime, taking into account the efficient use of water resources in the energy system, and should be carried out according to the criterion of minimum energy consumption at power plants involved in covering this capacity. The implementation of this principle is algorithmically fraught with difficulties associated with the use of the current telemetered mode parameters. At the same time, it is especially difficult to estimate the relative increases in power losses, since the relative increase in power losses from the power of power plants changes both with a change in the network layout and operating parameters [1].

II. Methods for assessing relative growth of power loss

In operational management, the optimization of active power distribution is the process of adjusting the regime for active power obtained during its short-term planning [2-4]. As with short-term planning, in a hydrothermal power system with operational control, the equation for the optimal distribution of active capacities between power plants is the equation:

$$\frac{b_1}{1-\sigma_1} = \lambda_a \frac{q_a}{1-\sigma_a} = \lambda_b \frac{q_b}{1-\sigma_b} = \cdots = \lambda_n \frac{q_n}{1-\sigma_n} \qquad (1)$$

The operational optimization algorithm consists in the implementation of the mode re-optimization equation (1) for active power.

It should be noted that of the parameters included in the operational optimization equation, only the coefficient of efficiency in the use of water resources λ and the coefficients of the characteristics of relative increases in energy consumption at power plant units are determined during short-term forecasting and from preliminary calculations, and the rest are either calculated during operational control using remotely measured parameters, or are set. At the same time, λ, found in the course of short-term forecasting, participate as constant coefficients in characterizing the relative increase in water consumption at HPPs.

In contrast to short-term planning, with operational optimization of the regime for active power, the optimization equation is characterized as follows: when the regime changes, unplanned power between stations must be distributed in such a way as to ensure the same relative increases in energy consumption at power plant units, taking into account the relative increases in power losses in the network from power these stations. At the same time, taking into account the relative increases in power losses from the power of power plants is a correction of the relative increases in energy consumption at the corresponding power plants. To implement the principle of optimality, it is necessary to quickly estimate the power losses and the relative increases in active power losses in the network.

An operational assessment of the relative increments of active power losses in the network is carried out either on the basis of the current values of the power of power plants or voltages in controlled nodes, and are found either by regression equations or by the method of average voltages.

As shown above, the distribution of unscheduled power, corresponding to the difference between current and forecast values, should be carried out according to the criterion of minimum fuel consumption on the units involved in covering this power and correspond to formula (1).

Included in the denominator of equation (1), the variable σ_i - is the relative increase in active power losses in the network from the power corresponding to the power plant. The use of σ_i values found from short-term calculations is impossible, since with a change in both the network scheme and the mode of operation of the power system, the values of σ_i also change, so it is necessary to use methods for determining σ_i at the pace of the process using the current telemetered mode parameters. Below are two methods for determining the relative increases in active power losses in the network.

III. Construction of analytical characteristics of relative increments of active power losses in electrical networks by node voltage vectors

In operational management, to determine the relative growth of power losses in the power system, telemetry of source voltage vectors can be used without introducing data on the parameters of the electrical network, loads of power plants and consumers into the calculations [5-6].

As is known, in the general case for heterogeneous networks.

$$\sigma_i^P + \vartheta_i^{g} = \frac{2\,(U_1 - U_0)}{U} \tag{2}$$
$$\sigma_i^{g} - \vartheta_i^P = 2\sin\delta_i \tag{3}$$

Where,

σ_i^P, σ_i^{g}, ϑ_i^P, ϑ_i^{g} – relative increments of active power losses by source active power, relative gains of active power by source reactive power, relative increments of reactive power losses by source active power and relative increments of reactive power losses by source reactive power, respectively, U_i- source voltage, U_0 - balancing node voltage, U is the average network voltage, σi is the angle between the voltage vectors of the sources and the balancing nodes.

In the general case, these equations are not enough to determine the relative power losses, since the number of unknowns is greater than the number of equations. For an approximate solution of these equations, we first neglect the inhomogeneity of the network, when the quality factor of all branches is assumed to be the same, i.e.

$$\psi_s = \mathrm{arctg}\frac{x_s}{r_s} = \mathrm{idem} \tag{4}$$

Then, taking into account

$$\vartheta_i^p = -\,\sigma_i^P \mathrm{tg}\psi \tag{5}$$
$$\vartheta_i^Q = -\,\sigma_i^Q \mathrm{tg}\psi \tag{6}$$

Equations (2) and (3) will take the form:

$$\sigma_i^p - \sigma_i^Q \mathrm{tg}\psi = \frac{2(\mathrm{U_i} - \mathrm{U_0})}{\mathrm{U}} \tag{7}$$
$$\sigma_i^Q + \sigma_i^P tg\psi = 2\sin\delta_i \tag{8}$$

By solving equations (7), (8) we obtain the following formulas for the relative gains in active power losses:

$$\sigma_i^p = \frac{2(\mathrm{U_i} - \mathrm{U_0})}{\mathrm{U}} \cos 2\,\psi + \sin\delta 1 \,\sin 2\psi \tag{9}$$
$$\sigma_i^Q = \frac{-(\mathrm{U_i} - \mathrm{U_0})}{\mathrm{U}} \sin 2\psi + 2\sin\delta 1\,\cos 2\,\psi \tag{10}$$

And if we neglect the difference in the phase angles of the power of the nodes, then $\mathrm{tg}\varphi_i = \frac{Q_i}{P_i}$, will be the same for all nodes, and then there will be the following relations between the relative gains in losses: $\sigma_i^Q = \sigma_i^p tg\varphi$ and $\vartheta_i^Q = \vartheta_i^P \mathrm{tg}\varphi$

In this case, equations (2) and (3) will take the following form:

$$\sigma_i^p + \vartheta_i^P \mathrm{tg}\varphi = \frac{2(\mathrm{U_i} - \mathrm{U_0})}{\mathrm{U}} \tag{11}$$
$$\sigma_i^p tg\varphi - \vartheta_i^P = 2\sin \delta\mathrm{i} \tag{12}$$

By solving equations (11) and (12), we obtain the following equations for relative loss increments:

$$\sigma_i^p = \frac{2(U_i - U_0)}{U} \cos 2\varphi + \sin\delta 1 \sin 2\varphi \quad (13)$$

$$\sigma_i^Q = \frac{(U_i - U_0)}{U} \sin 2\varphi + 2\sin\delta 1 \sin 2\psi \quad (14)$$

As can be seen from Figure 1, the sum of the right and left parts of equations (9) and (10) for different values of the quality factor of all branches is a band of possible solutions limited between tgψ_{max} and tgψ_{min} on the voltage plane and an increase in active power losses[7-9].

And the sum of the right and left parts of the equation (13) and (14) at different values of the phase angles of power is a band of possible solutions limited between tgφ_{max} and tgφ_{min} on the voltage plane and increase in active power losses.

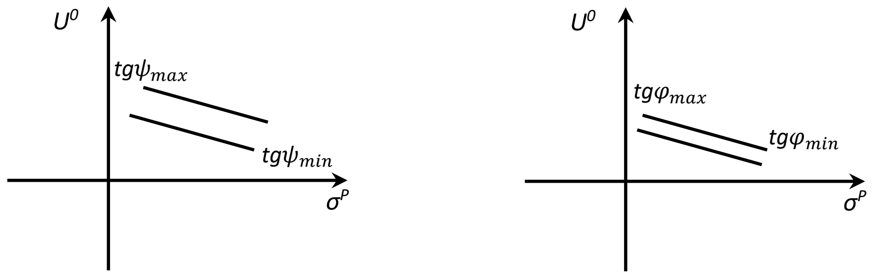

Figure 1.*a) The dependence of σP on voltage at the same quality factors of the branches*
b) The dependence of σP on voltage at the same phase angles of power in the nodes

Adding the left and right parts of equations (9), (10), (13), (14) and dividing by 2, we obtain the equations for the relative increments of active power losses in the network for two averaged parameters.

$$\sigma_\iota = \frac{(U_i - U_0)}{U} (2\cos 2\psi + 2\cos 2\varphi - \sin 2\psi + \sin 2\varphi)$$
$$\sin\delta 1 (\sin 2\psi + \sin 2\varphi + 2\cos 2\psi + 2\sin 2\varphi) \quad (15)$$

Equation (15) is a combination of two graphs shown in fig. 1 and therefore the boundary of possible changes in the relative increments of losses becomes even narrower and therefore the accuracy of the calculations increases. Let us denote the coefficients of two variables $\frac{(U_i - U_0)}{U}$, sinδ1,, inside the brackets, respectively, A and B, then equation (15) will take the form:

$$\sigma_\iota = A \frac{(U_i - U_0)}{U} + B\sin\delta 1 \quad (16)$$

The relative increase in active power losses is obtained as a function of two variables $\frac{(U_i - U_0)}{U}$ and sinδ1, Ui and U0 are the voltages of the source and the balancing node, they are usually maintained at the nominal value, telemetered and can be used at the pace of the control process.

It should be noted that the resulting equation can be used for operational control if the coefficients for two variables $\frac{(U_i - U_0)}{U}$ and sinδ1 are determined from preliminary calculations, since it is not possible to determine the components of the equation inside the brackets at the pace of the process. To obtain a working formula for a quick assessment of the relative increase in power losses, it is necessary to calculate a number of characteristic modes of the power system with the determination of the coefficients A and B in equation 16, and also determine U - the average voltage of the network. The fact is that the use of the U-average voltage of the network is difficult because usually the voltage telemetry contains significant measurement errors. Therefore, to determine the average network voltage, one can use the regression dependences of the average voltage as a function of the voltage of some nodes. To determine these nodes, it is possible to carry out steady state calculations for normal and post-accident modes with the determination of the nodes on the voltage of which the mains voltage mode depends to the greatest extent, the so-called sensor nodes. The voltage of these nodes can be taken as factors for determining the average network voltage.

To determine the coefficients A and B, calculations were made for some characteristic modes of the Azerenerji energy system. The results of calculations with the determination of the coefficients A and B are given below:

№	A	B
1	0.0021	0.172
2	0.0025	0.165
3	0.0022	0.167
4	0.0024	0.169
5	0.0023	0.168

It can be seen from the table that coefficient A changes in ten-thousand digits, and B - in thousandth digits, so the arithmetic average value will correspond quite accurately to the desired coefficients:

Avr.= 0.0023, Vav.= 0.168 and equation (16) will take the form:

$$\sigma_\iota = 0.0023\,\frac{(U_i - U_0)}{U} + 0.168\sin\delta 1 \qquad (17)$$

To determine U - the average voltage of the network as a function of the voltages of some nodes, calculations of normal modes and post-emergency modes were carried out in the Azerenergy system, obtained by typical outages of some power lines, a total of 64 calculations. As a result, 7 nodes were identified, on the voltage of which the mains voltage mode depends to the greatest extent, the so-called sensor nodes. The voltages of these nodes were determined as factors for determining the average network voltage. Below, without details, the found regression coefficients for the mean stress are given.

U= 121 + 0.7722 UHOV + 0.4930 UMUSH +0.5923 UKHUR+
0.2215 UMAS+ 0.4622 UAKSU+0.2123 UAGC+0.3311 UAGS (18)

In this case, the standard deviation (SD) at the experimental points is 0.7%, and in the basic modes, when all factors are taken at an average level, the SD is 1.5%, which is at the level of the error in measuring telemetered node voltages. Thus, according to the telemetered values of the voltages of the sources, the balancing node and the 7 nodes listed above, it is possible to determine the relative increases in power losses in the network at the pace of the process.

Numerous calculations of the relative increases in power losses by the voltage vectors of the nodes show that the error for the minimum and maximum modes is greater (8%) than for the typical average modes (5%), when operational optimization of the modes by active power is possible.

IV. Construction of analytical characteristics of the relative increase in losses in the network by the active capacities of power plants

Here, it is required to build the dependence ΔP(Pi) on the basis of the experiment planning matrix, where Pi is the load of power plants participating in the operational optimization of the regime. As is known, on the basis of the experiment planning matrix, equations are obtained with normalized values of the factors, i.e. varying from +1 to -1. For management purposes, not normalized, but natural values of factors are needed. In this regard, the construction of equations by natural values and their analysis are considered [10].

To obtain a regression equation with natural values of the factors, regression equations were constructed to determine the power losses in the power system, where the following power plants were the factors with the ranges of change in their total load for characteristic modes.

1. Shimal PP (760-560 MW)
2. Sumgayit PP (500-300 MW)
3. Canub PP (700-500 MW)
4. Azerbaijan TPP (1780-1580 MW)
5. Gobu PP (380-180 MW)

Regression models were obtained in a fractional-factorial experiment of the type N=25-1=24=16, in which the results of ΔP analyzes show a fairly high accuracy of the models. The planning matrix, indicating the interaction of factors used as additional factors and the interaction used in the regression equation, are given below. The losses ΔP in the network, obtained as a result of calculating the steady state using the corresponding program, are also indicated there.

Tab. 1

Table 1: *Planning matrix*

№	Shimal PP X1	Sumgayit PP X2	Canub PP X3	Azerbaijan TPPX4	Gobu PP X5	ΔP
1	760+j400	500+j300	700+j400	1780+j900	380+j200	110,7
2	530+j280	500+j300	700+j400	1780+j900	180+ j100	99,1
3	760+j400	300+ j160	700+j400	1780+j900	180+ j100	98,4
4	530+j280	300+ j160	700+j400	1780+j900	380+j200	97,1
5	760+j400	500+j300	500+ j280	1780+j900	180+ j100	101,8
6	530+j280	500+j300	500+ j280	1780+j900	380+j200	99,9
7	760+j400	300+ j160	500+ j280	1780+j900	380+j200	99,2
8	530+j280	300+ j160	500+ j280	1780+j900	180+ j100	104,9
9	760+j400	500+j300	700+j400	1580+ j800	180+ j100	100,9
10	530+j280	500+j300	700+j400	1580+ j800	380+j200	99,1
11	760+j400	300+ j160	700+j400	1580+ j800	380+j200	98,4
12	530+j280	300+ j160	700+j400	1580+ j800	180+ j100	104,1
13	760+j400	500+j300	500+ j280	1580+ j800	380+j200	102
14	530+j280	500+j300	500+ j280	1580+ j800	180+ j100	107,4
15	760+j400	300+ j160	500+ j280	1580+ j800	180+ j100	106,5
16	530+j280	300+ j160	500+ j280	1580+ j800	380+j200	105,3

Below, without details, the regression equation ΔP and the relative increase in power losses for characteristic modes are carried out.

For the operational optimization of the active power mode, the controlled parameters are the capacities of the power plants Shimal ES, Sumgayit ES, Janub ES and Azerbaijan TPP, and therefore the relative increases in power losses are determined as partial derivatives of the equation of power losses with respect to the capacities of the corresponding stations.

$$\Delta P = 622{,}97 - 0{,}3201{*}X1 - 0{,}3405X2 - 0{,}3445X3 - 0{,}2185X4 - 0{,}357X5 + 0{,}000118X1X2 + 0{,}000106X1X3 + 0{,}000107X1X4 + 0{,}000105X2X3 + 0{,}000105X2X4 + 0{,}000102X3X4$$

$$\sigma 1 = -0{,}3201 + 0{,}000118X2 + 0{,}000107X4$$
$$\sigma 2 = -0{,}3405 + 0{,}000118X1 + 0{,}000105X3$$
$$\sigma 3 = -0{,}3445 + 0{,}000106X1 + 0{,}000105X2$$
$$\sigma 4 = -0{,}2185 + 0{,}000107X1 + 0{,}000105X2$$

The resulting models at all experimental points have a very high accuracy. Numerous calculations show that the standard deviation of the calculated data from the experimental data is on average 4% for the maximum and minimum modes, and 7% for the middle modes, when operational optimization is possible. If we take into account that the proposed regression equations will be used in the additional optimization of the regime with the operational management of the distribution of approximately 200 MW of unscheduled active power, then the above deviations fall within the accuracy of the initial data and they can be used for the purposes of operational optimization.

V. Discussion

[1] N. Yusifbayli, V. Nasibov, R. Alizade Power consumption management and equalization of the load schedules of Azerbaijan power system. Rudenko International Conference "Methodological Problems in Reliability Study of Large Energy Systems" (RSES 2022) Volume 384, 2023

[2] Christoph Graf, Federico Quaglia&Frank A. Wolak Simplified Electricity Market Models with Significant Intermittent Renewable Capacity: Evidence from Italy https://www.nber.org/papers/w27262

[3] Mariano Ventosa, Alvaro Baillo, Andres Ramos, Michel Rivier Electricity market modeling trends. Energy Policy, Volume 33, Issue 7, May 2005

[4] The European Electricity Market Model EMMA Model documentation, Latest version http://neon-energie.de/emma

[5] M. Y. Hassan; M. P. Abdullah; A. S. Arifin; F. Hussin; M. S. Majid Electricity market models in restructured electricity supply industry, https://ieeexplore.ieee.org/document/4762618

[6] L.S. Belyaev Electricity market problems, 2009 https://isem.irk.ru/upload/iblock/228/228f43e79d0cd2692c29ae64199ad2e2.pdf

[7] Hawker G., Bell K., Gill S. Electricity security in the European Union. The conflict between national Capacity Mechanisms and the Single Market. Energy Research & Social Science, №24, 2017

[8] L.S. Belyaev, O.V. Marchenko, S.V. Podkovalnikov Growth of electrical energy prices necessary for energy system development at transition to competitive market https://www.researchgate.net/publication/292808323_Growth_of_electrical_energy_prices_necessary_for_energy_system_development_at_transition_to_competitive_market

[9] Site of State Statistical Committee of the Republic of Azerbaijan, https://www.stat.gov.az/index.php

[10] L.A. Barroso; T.H. Cavalcanti; P. Giesbertz; K. Purchala Classification of electricity market models worldwide. International Symposium CIGRE/IEEE PES, New Orleans, LA, USA, 2005