Energy Systems Research

Volume 2 • Number 2(6) • 2019

Published by
Melentiev Energy Systems Institute
Siberian Branch of Russian Academy of Sciences

Available online: esrj.ru

ISSN 2618-9992

Energy Systems Research

Volume 2 • Number 2 • 2019
International scientific peer-reviewed journal
Available online: http://esrj.ru

About the journal

Energy Systems Research is an international peer-reviewed journal addressing all the aspects of energy systems, including their sustainable development and effective use, smart and reliable operation, control and management, integration and interaction in a complex physical, technical, economic and social environment.

Energy systems research methodology is based on a systems approach considering energy objects as systems with complicated structure and external ties, and includes the methods and technologies of systems analysis.

Within this broad multi-disciplinary scope, topics of particular interest include strategic energy systems development at the international, regional, national and local levels; energy supply reliability and security; energy markets, regulations and policy; technological innovations with their impacts and future-oriented transformations of energy systems.

The journal welcomes papers on advances in heat and electric power industries, energy efficiency and energy saving, renewable energy and clean fossil fuel generation, and other energy technologies.

Energy Systems Research is also concerned with energy systems challenges related to the applications of information and communication technologies, including intelligent control and cyber security, modern approaches of systems analysis, modeling, forecasting, numerical computations and optimization.

The journal is published by Melentiev Energy Systems Institute of Siberian Branch of Russian Academy of Sciences. The journal's ISSN is 2618-9992. There are 4 issues per year (special issues are available). All articles are available online on English as Open access articles.

Topics

- Energy production, conversion, transport and distribution systems
- Integrated energy systems
- Energy technologies
- International, regional, local energy systems
- Energy system protection, control and management
- Smart energy systems, smart grids
- Energy systems reliability and energy security
- Electricity, heating, cooling, gas and oil systems
- Energy system development and operation
- Demand-side management
- Energy economics and policy
- Renewable energy and clean fossil fuel based systems
- Distributed energy systems
- Sustainable energy transitions
- System problems of power and thermal engineering
- Artificial intelligence in energy systems
- Information and communication technologies in energy systems
- Energy systems analysis and modelling
- Computational methods and optimization in energy systems

Contacts

Scientific secretary:	Alexey Mikheev, Dr. of Eng.
E-mail:	info@esrj.ru
Tel:	+7 (3952) 950980 (English, Russian)
Fax:	+7 (3952) 426796
Address:	130, Lermontov str., Irkutsk, 664033, Russia

Contents

A System Of Models To Study Long-Term Operation Of Hydropower Plants In The Angara Cascade 5
N.V. Abasov, V.M. Nikitin, E.N. Osipchuk

Algorithms For Considering The Temperature Of Overhead Conductors In The Calculation Of Steady States Of An Electrical Network 19
Oleg Voitov, Ekaterina Popova, Ludmila Semenova

Locational Marginal Pricing in Multi-Period Power Markets 28
Tatiana A. Vaskovskaya

Energy Security and Critical Facilities of Energy Systems: Methodology and Practice of their Identification on the Example of Russia's Gas and Electric Power Industries 41
Sergey Senderov, Dmitry Krupenev

Imperfection Of Electricity Markets 51
Lev Belyaev

Control Strategies For Maximizing Renewable Energy Utilization In Power Systems 63
Michael Negnevitsky, Evgenii Semshchikov, James Hamilton, Xiaolin Wang ,
Ekaterina Bayborodina

A Technique For Calculation Of Life Limits Of Electrical Network Equipment 72
Alexander Nazarythev

A System Of Models To Study Long-Term Operation Of Hydropower Plants In The Angara Cascade

N.V. Abasov, V.M. Nikitin*, E.N. Osipchuk

Melentiev Energy Systems Institute of Siberian Branch of Russian Academy of Sciences, Irkutsk, Russia

***Abstract* — The paper provides a system of consistent models to study the integrated use of water resources of reservoirs and operating conditions of hydropower plants that constitute the Angara cascade. The system includes many different simulation and optimization models (hydrological, hydraulic, water management, and the hydropower cascade operation control) taking into account the hydrological, climatic and territorial features of the water systems of the Baikal, Angara and Yenisei basins; and the role of the Angara cascade in the operation of the Siberian electric power system. The paper presents a brief description of the models, their parameters, criteria and constraints, and their interaction principles. The models are designed to determine the long-term operating conditions of the Angara cascade of hydroelectric power plants. To this end, it is proposed to use global climate models with the data on the state of the atmosphere and ocean based on which the most probable characteristics of meteorological indices in the region are determined, to make estimates (scenarios) of inflows into the cascade reservoirs in the form of ranges of probability distributions for a period of up to one year. The results of modeling the long-term operation of individual hydroelectric power plants and the entire Angara cascade are presented for 2019–2020. Relying on the assumed long-term water scenario, the estimated water availability scenarios make it possible to evaluate the expected electricity output, the average used capacity and other parameters of the hydroelectric power plants operation, to form prospective energy balances in the power system, and to determine the the prospective load of thermal power plants.**

***Index Terms* — hydropower plant operation, Angara cascade, metamodels, inflow scenarios.**

I. Introduction

In the electric power system of Siberia, 50% of generating capacities are represented by hydroelectric power plants, including 30% of the Angara cascade hydropower plants and 20% of the Yenisei cascade plants. For comparison, the share of hydroelectric power plants in the Unified Power System of Russia accounts for about 17% of the installed capacity of all power plants. The share of hydroelectric power plants in other power systems is much lower: 12 % in the North-West; 10% – in the Central, and 3% – in the Urals [1].

The Angara cascade is located in the Angara river basin and includes Irkutsk, Bratsk, Ust-Ilimsk, and Boguchany hydroelectric power plants (HPPs) with reservoirs of seasonal and long-term regulation with a total live storage capacity of about 100 km3 [2–4]. Figure 1 shows a diagram of the Angara river basin divided into five main areas connected to the catchment basins of the reservoirs of the Angara HPP cascade. Area 1 refers to Lake Baikal [5–7] and the upper and lower pools of the Irkutsk reservoir. Areas 2–4 correspond to the catchment basins of the lateral tributaries to the Bratsk, Ust-Ilimsk, and Boguchany reservoirs. Area 5, 450 km long along the river bed, is important for summer navigation on the Lower Angara and the Yenisei rivers.

Since most of the electricity in the electric power system of Siberia is generated by hydropower plants, its operation and management of the operation largely depend on the natural fluctuations in the annual flow of the Angara-Yenisei basin rivers. Depending on the water availability, the range of changes in the electricity generation from the

* Corresponding author.
E-mail: nikitin1310@mail.ru

http://dx.doi.org/10.25729/esr.2019.02.0001
Received September 13, 2019. Revised October 15, 2019
Accepted October 23, 2019. Available online October 31, 2019.

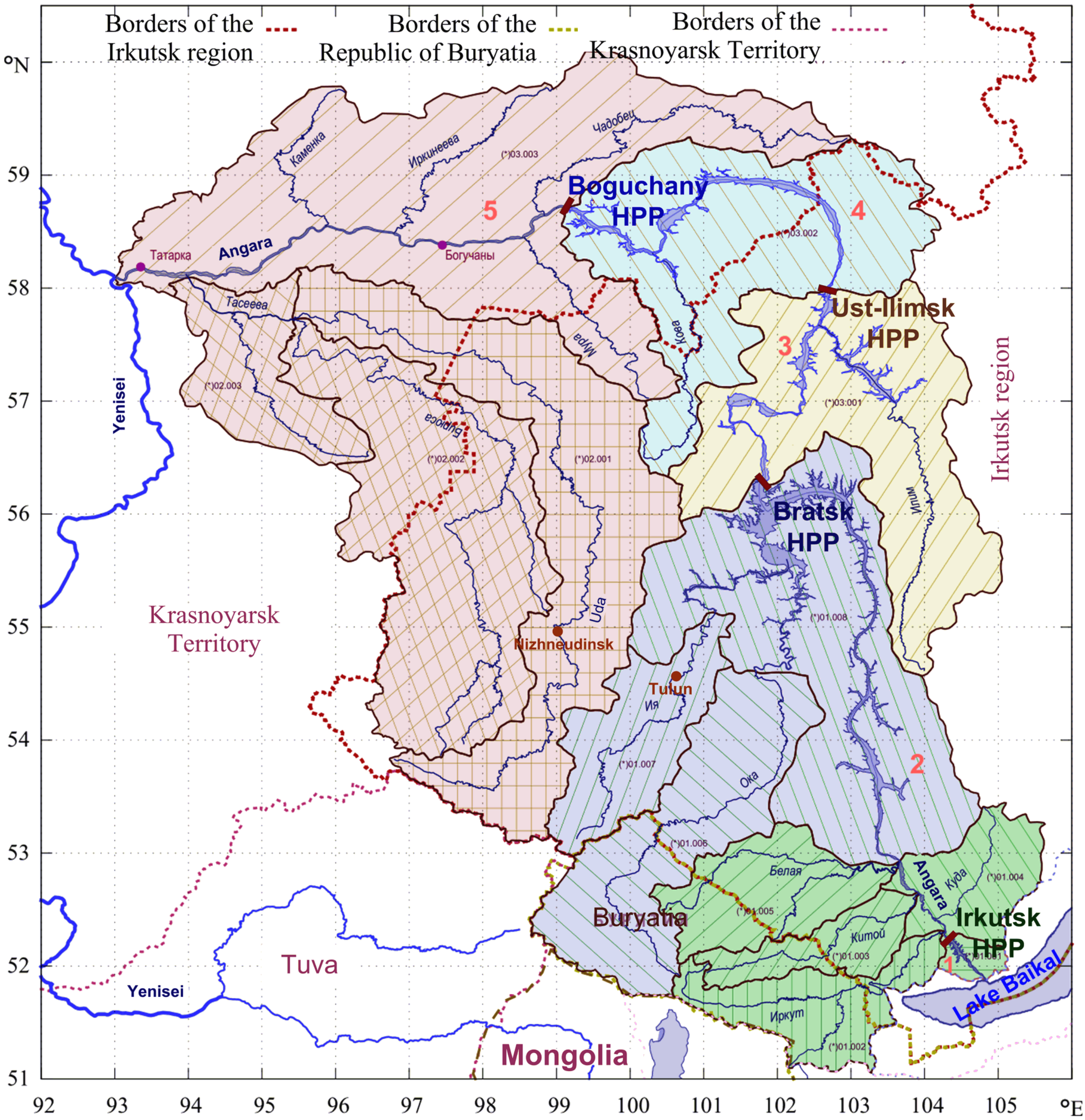


Fig. 1. Map of the Angara HPP cascade reservoirs with catchment basins (1–4) and Lower Angara area (5).

Angara-Yenisei HPP cascade can reach 50 billion kWh per year, including 30 billion kWh from the hydropower plants of the Angara cascade. For example, during the period of extremely low water observed in the Angara cascade of hydropower plants in 2014–2017 (2018), there was a significant decrease in the generation of electricity by hydroelectric power plants (up to 20% in some years). The low water period led to a reduction in the reserves of hydro resources in the reservoirs of the hydroelectric power plants, including the almost complete drawdown of long-term reserves in the Bratsk reservoir. As a result, the electricity output from the hydroelectric power plants decreased and the need arose to additionally load less economical and less environmentally friendly thermal power plants, which increased fuel consumption, electricity cost, and emissions of harmful substances into the environment. As a result, the efficiency and reliability of the entire power system of Siberia decreased.

It is worth noting that the presence of a powerful cascade of hydroelectric power plants in the power system is characterized by both advantages (the use of efficient renewable energy resources) and disadvantages of the power system. The main disadvantage is the uncertainty of the available water resources in the estimated period.

The existing system of planning and management in the electric power industry envisages the estimation of long-term operating conditions and balances of electric power and capacity for a period of 1–2 or more years. To this end, to plan the operation of hydropower plants, it is necessary to take into account the long-term forecast scenarios of water availability, which are probabilistic in nature. The development of such scenarios is an extremely complex problem that does not have unambiguous solutions. In practice, the water-energy calculations for the long-term prospects normally involve statistical average long-term values of water inflows into reservoirs. Under normal (medium) water conditions, this approach does not cause problems but it cannot be applied to low-water and high-water periods.

The noted features of the power system and the hydropower plant cascade, as well as the need to improve the reliability of their operation call for a study of various operating conditions of the hydrosystems based on a variety of simulation and optimization models with the determination and minimization of energy, water, environmental and social risks.

II. Research Methodology

Many effective algorithms and techniques have been developed to study the operation of hydropower plants in recent decades. Many of them have been created since the early 1960s and used in automated dispatch control of power systems to perform water-energy calculations aimed at regulating the storage reservoirs. The mathematical methods (linear, nonlinear, dynamic programming) [8–10] designed to optimize the hydrological regimes, including stochastic [11–14] and multi-criteria [15–17] optimization found wide application.

The development of global climate models brought about the studies on their application in the estimates of future river flow and calculations of hydropower water-energy regimes [18, 19]. Some studies suggest the use of an integrated approach to managing cascades of reservoirs (using the Volga-Kama cascade of hydroelectric plants as an example) with focus on the water system requirements based on various methods of determining surface runoff, allowing for weather parameters, and using digital models of river catchment relief [20].

Given the role of the Angara cascade of hydropower plants and its reservoirs in the operation of the regional power system of Siberia; the water-management systems of the Baikal, Angara and Yenisei basins, as well as the hydrological, climatic and territorial features of the studied object; it is necessary to build a great variety of models (hydrological, hydraulic, water management, simulation, optimization, stochastic and others), because consideration of all aspects of the object operation in one model greatly complicates its use in practice. Figure 2 shows a system of

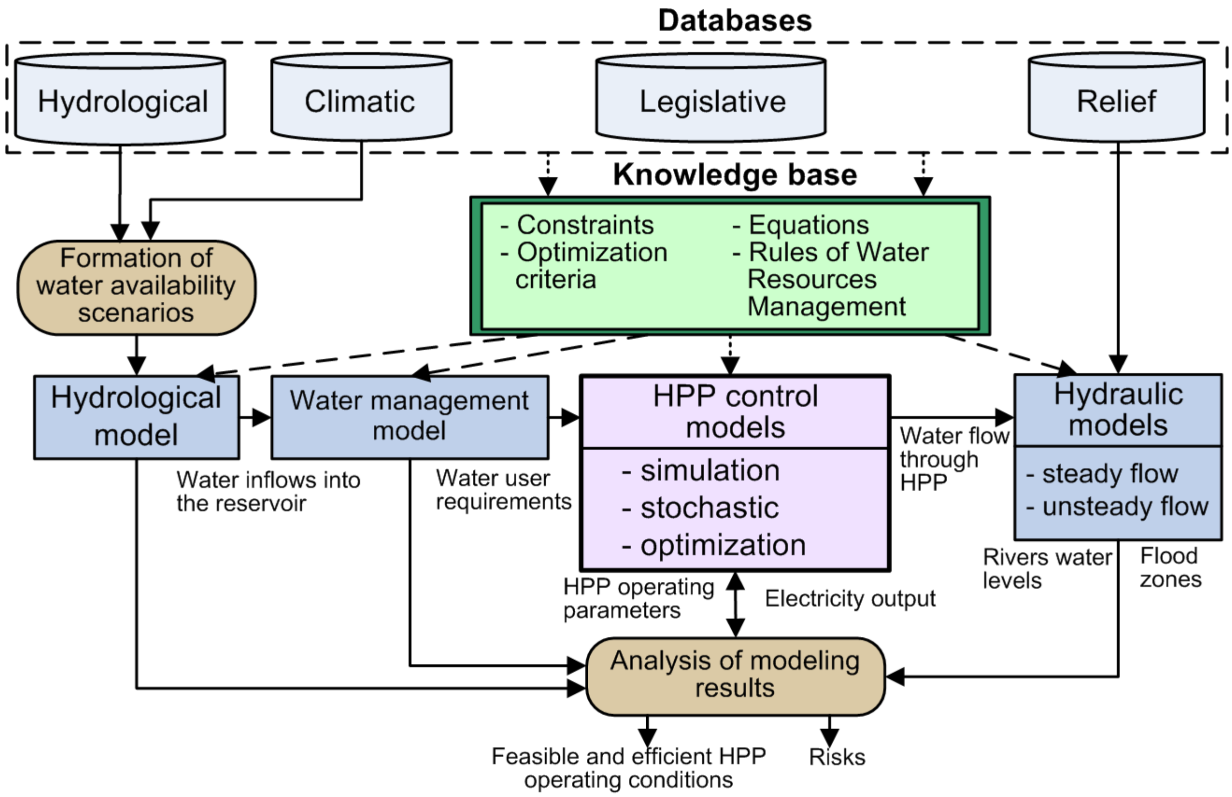


Fig. 2. A system of models for studying the integrated use of water resources of reservoirs and operation of the Angara cascade hydropower plants.

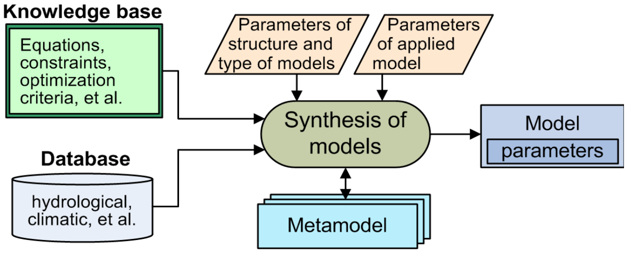


Fig. 3. A diagram of constructing consistent models to study HPP operating conditions.

models developed by a research team from the Laboratory of Hydropower and Water Management Systems at the Melentiev Energy Systems Institute (ESI) SB RAS to study the integrated use of water resources of reservoirs and operation of the hydropower plants of the Angara cascade [21, 22].

The hydrological database includes the collected statistics on the water inflows into the reservoirs of the hydropower plants. The climatic database, including the state of atmospheric meteorological indices for a long period of observations, together with the forecast ensembles of global climate models, is used to build long-term prognostic scenarios of water availability in the cascade reservoirs with the aid of the GeoGIPSAR system developed at ESI SB RAS [23, 24]. The relief database of the Angara river areas is used to build hydraulic models for steady (stationary) and unsteady (non-stationary) flow. These models can be used to determine river levels and, accordingly, periods of water level reaching the specified cross-sections, zones and boundaries of potential flooding. The knowledge base includes formalized current rules for the use of water resources of the reservoirs, as well as various constraints on operating conditions of the Angara cascade of hydropower plants with different criteria for their optimization.

The hydrological model includes balance equations for water inflows and flow rates. The water management model takes into account transport, energy, social, and environmental constraints; the requirements for uninterrupted operation of water intakes, and other requirements of the water management system.

Formation of feasible and optimal operating conditions normally requires multiple uses of various models with a block for analysis of the complex modeling results. There are periodic changes in regulatory documents, significant changes in hydrological and climatic characteristics in recent decades, various criteria used for the formation of effective conditions, which makes it necessary to constantly update the models.

To eliminate the contradictions in the use of different models, the ESI SB RAS has developed an approach to the development of a system of consistent models based on common data and knowledge bases and various model structures based on a metamodeling mechanism, which makes it possible to quickly synthesize unique models based on the description of parameterized model classes, i.e. metamodels [25–28]. A general diagram of this approach is shown in Fig. 3.

The metamodel is a parameterized structure that includes many relations with knowledge base and database objects.

Based on a single knowledge base and a single database, models of different classes (mathematical programming, stochastic, simulation, and others) are synthesized. Planning the operating conditions of the HPP cascade involves consideration of various control methods: setting reservoir levels by the end of the time interval, setting average water flow rates through HPP turbines, assigning a guaranteed average power or electricity output from hydropower plants.

The problem of operating the hydropower plants in the power system and in the water management system lies in the difficulty of describing and considering a large number of processes and their parameters: the requirements of the participants in the water management, including energy industry, the influence of natural, climatic, economic, and social factors.

The proposed approach is characterized by:

- the development of many models based on a single database and a single knowledge base, coordinated with respect to input and output parameters and constraints;
- the creation of an environment for the synthesis of the management models with various water and energy optimization criteria based on the processing of long-term hydrological statistical data and their model options (for example, the formation of artificial time series for 1000 years or more);
- the modeling of long-term operating conditions of hydropower plant cascades according to synthesized prognostic scenarios of water availability with their different probabilities;
- the development of a flexible parameterized software environment for the synthesis, start, and development of models based on the creation of universal and specialized libraries of support programs;
- the combination of the use of own and external software;
- the consideration of the specifics of the basins of Lake Baikal, the Angara, theYenisei, and the Angara cascade.

III. Research models of Angara HPP cascade

The hydrological model serves as a basis for the study of the Angara HPP cascade operation. The water inflows and discharges in the cascade are schematically presented in Fig. 4.

For the Bratsk reservoir, additional lateral tributaries (the Irkut, the Kitoy, and the Belaya rivers) were considered, which is associated with the potential flooding of large areas in the lower reach of the Irkutsk HPP, determined by the flow through its hydrosystem and these lateral tributaries [29].

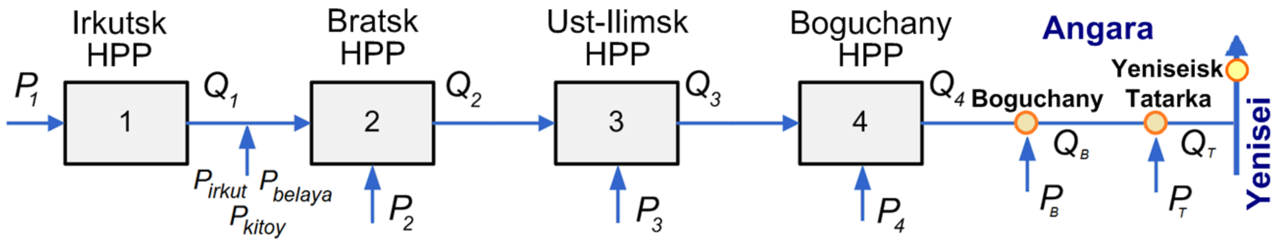


Fig. 4. A scheme of the Angara HPP cascade

The hydrological model of the Angara cascade can be represented by the following equations:

$$\begin{aligned}
&\frac{dV_i}{dt} = P_i(t) - Q_i(t) + \overline{Q}_{i-1}(t) - \Lambda_i(t),\\
&Q_B(t) = Q_4(t) + P_B(t),\\
&Q_T(t) = Q_B(t) + P_T(t), Q_0(t) = 0,\\
&\Lambda_i(t) = R_i^{isp}(t) + R_i^{filtr}(t) + R_i^{pz}(t) + R_i^{tr}(t),\\
&t \in [t_0, T],\ i = \overline{1,4},
\end{aligned} \tag{1}$$

where i – an HPP index (1 – Irkutsk, 2 – Bratsk, 3 – Ust-ILimsk, and 4 – Boguchany HPPs);
t – time on the set interval $[t_0, T]$; V_i, (t) – the volume of water in the reservoir;
P_i, (t) – lateral (full) water inflow into reservoir; Q_i, (t) – flow through HPP cross-section; $\overline{Q}_{i-1}(t)$ – water consumption of the upper stage of the HPP cascade, given the lag time; Q_B, Q_T, P_B, P_T – flows and lateral inflows into the Lower Angara for the Boguchany and Tatarka points where the Angara river levels are monitored; $\Lambda_i(t)$ – function of an additional impact of evaporation from the reservoir surface $R_i^{isp}(t)$, filtering through the dam $R_i^{filtr}(t)$, changes in the subsurface component $R_i^{pz}(t)$, changes in the volume of a water area between the reservoir and upper stage of the HPP $R_i^{tr}(t)$. The indices of inflows $P_i(t)$ can be taken from the hydrological base or specified by various prediction scenarios built by the GeoGIPSAR system.

The values of functions $\Lambda_i(t)$, except for evaporation, can be neglected for practical calculations, which is due to the complexity of estimate of the listed indices and their relatively small influence on the total inflow. Evaporation plays a significant role in dry periods on Lake Baikal, therefore, its indices are included in the final available inflow into the Irkutsk reservoir.
For the given time interval, equation (1) can be approximately written in the finite difference form:

$$\begin{aligned}
\Delta V_i^{\tau}(t) = [Q_{i-1}^{\tau}(t) + P_i^{\tau}(t) - Q_i^{\tau}(t) -\\
R_i^{isp}(t)] \cdot \tau, Q_0^{\tau}(t) = 0, i = \overline{1,4}
\end{aligned} \tag{2}$$

Constraints on the upper reach:

$H_i^{UMO} \le H_i(t) \le H_i^{NPU}$ – for normal water conditions;
$H_i^{UMO-} \le H_i(t) \le H_i^{FPU}$ – for extreme water conditions;

Constraints on the flow rates:

$$q_i^{turb}(t,j) \le q_i^{\max}(h_i), \quad q_i^{hol}(t,k) \le q_i^{hol,\max}(h_i)$$

Statistical calibration functions:

$$z_i = \varphi_i^z(Q_i, H_{i+1}^{vb}), \quad E_i^{\max} = \varphi_i^E(Q_i, h_i),$$
$$H_i = \psi_i(V_i), \quad V_i = \psi_i^{-1}(H_i)$$

where $\Delta V_i^{\tau}, P_i^{\tau}, Q_i^{\tau}, R_i^{\tau}$ – average values of the function on the time interval $[t, t+\tau]$. The lag time of the changed water flow from the Boguchany HPP is determined by the average speeds for the respective sections.

Water inflow functions $P_i^{\tau}(t)$ have large interannual and seasonal variations, which significantly complicates the management of the regimes. The hydrological model makes it possible to calculate the natural regimes of each reservoir using the equations of water volume dynamics. This model can also be used to determine the natural flow from Lake Baikal based on the family of curves of correlation between its level and the level of upper reaches of the Irkutsk hydropower plant dam. All lateral inflows and effective inflow into Lake Baikal are determined by the corresponding probability distribution functions (Kritsky-Menkel three-parameter distribution, Pearson type III distribution, etc.), which are built based on hydrological statistics in ten-day and monthly temporal resolution for the period of 1903–2018.

The water management model allows for the consumptive water use in different parts of the Angara river. Then equations (1) will take the form:

$$\begin{aligned}
&\frac{dV_1}{dt} = P_1(t) - Q_1(t) - \Lambda_1(t) - \beta_1(t)\ ,\\
&\frac{dV_2}{dt} = Q_1(t) + P_2(t) + P_{irkut} + P_{kitoy} + P_{belaya}\\
&- Q_2(t) - \Lambda_2(t) - \beta_2(t)\ ,\\
&\frac{dV_3}{dt} = Q_2(t) + P_3(t) - Q_3(t) - \Lambda_3(t) - \beta_3\ (t),\\
&\frac{dV_4}{dt} = Q_3(t) + P_4(t) - Q_4(t) - \Lambda_4(t) - \beta_4\ (t),
\end{aligned} \tag{3}$$

where functions $\beta_i(t)$ determine the total consumptive water withdrawal by water users at the relevant macro area with constraints $\beta_i(t) \le \beta_i^{\max}$.

The main water management constraints are:

$q_{ij}(t) \geq q_{ij}^{\min}$ – flow rates for all water withdrawals of macro area i and area j should be larger than the minimum permissible ones for the area;

$h_{ij}(t) \geq h_{ij}^{\min}$ – similarly, the levels of the river by area for the open water in the zone of water withdrawal should be higher than the minimum permissible ones.

For the normal (failure-free) operation of water diversion points in the lower reach of Irkutsk hydropower plant at present the required flow rates through the hydrosystem should be no less than 1300 m3/s (1250 m3/s when the hard ice cover is formed).

For the Bratsk reservoir, the level of the upper reach should not be below 392.73 m of the Baltic Elevation System (BS) (according to the operating conditions of the diversion facility in Svirsk). Indices of consumptive water use by water consumers are taken into account in water balance equations.

Normal navigation conditions in the lower reach of the Irkutsk hydropower plant require the flow rate through the hydrosystem to be no less than 1500 m3/s during the period from May to October. For the Bratsk reservoir, the navigation level according to the current rules [3] should be at least 394.73 m BS during the period from June to October. For the Ust-Ilimsk and Boguchany reservoirs, the normal navigation levels correspond to 295.5 and 207.5 m BS, respectively. The level of pre-flood drawdown for each reservoir as of May 1 should not exceed 456.15 m of Pacific Altitude System (PS) for Lake Baikal; 400.23 m BS for Bratsk reservoir; 295.19 m BS for Ust-Ilimsk reservoir, and 207.20 m BS for the Boguchany reservoir.

For all reservoirs in the cascade, the maximum permissible level of the upper reach is limited to the normal water surface (NWS), except for periods of extremely high floods.

The most severe limitation in the summer-autumn period (from May to October) is the maintenance of the Lower Angara and Yenisei levels not lower than the minimum permissible levels for the three control sites (Boguchany – not lower than 0 cm; Tatarka – not lower than 180 cm; Yeniseisk – not lower than 300 cm relative to the base marks of the corresponding water points), providing navigation on the Yenisei.

Water withdrawal constraints (limits and norms of permissible impacts) are taken into account for each section of the Angara river basin.

The hydraulic model is used to estimate the flooding zones in the lower reach of the Irkutsk hydropower plant, as well as in the unregulated areas of the Lower Angara for the current calculation of the Angara river levels at the control cross-sections of Boguchany and Tatarka.

The calculations for the steady-state flow are based on the Chezy equation [30] used to calculate the average flow velocity in an arbitrary cross-section:

$$\upsilon = C\sqrt{R \cdot I} \tag{4}$$

$$\begin{gathered} P = \sum\nolimits_{(i)} l_i, \; S = \sum\nolimits_{(i)} s_i, \; B = \sum\nolimits_{(i)} b_i, \\ l_i = \sqrt{h_i^2 + b_i^2}, \; s_i = (h_{i-1} + h_i) \cdot b_i / 2, \; i = \overline{1, N}, \\ R = S / P, \; Q = \upsilon \cdot S, \; K = C \cdot S \cdot \sqrt{R}, \\ C = R^y / n_i, \; y = 1/6, \end{gathered} \tag{5}$$

where P – wetted perimeter; S – area; B – width; Q – flow rate; K – flow rate characteristic; h_i, b_i, l_i, s_i, n_i – depth, width, length, area, and roughness of the i-th section of the cross-section.

For the case of a small change in the river level, the iteration method is used to calculate these indices with a given error based on given and calculated flow rates.

For a given flow rate, the morphometric characteristics are calculated for each of the cross-sections, starting with the last one located downstream, for which the level is determined by the Chezy equation. The roughness coefficients for the initial calculations are divided into two parts: the riverbed one in a range of 0.02–0.05 and the floodplain one in a range of 0.05–0.07. The roughness coefficients are specified through verification of levels for several hydrological points (the Irkutsk hydropower plant dam, the Yunost Island, the bridge, the river port, the village of Bokovo, and the town of Angarsk) according to the available statistical indices of daily levels of the Angara river in the high water years (1971, 1973, 1985, 1988, 1994, 1995, 1998, and others).

After the iterative procedures of the level refinement in each basic cross-section, the structure of their characteristics is formed. These characteristics are used to determine the parameters of intermediate cross-sections with a water surface level change uniform in length and refinement of hydraulic parameters.

For the *unsteady flow* associated with unregulated lateral inflows, the difference scheme of calculations based on the Saint-Venant equations is applied. Estimation of an average ten-day flow at point X, situated at distance L from the initial one, can be defined as follows:

$$\begin{gathered} Q^X = {}^1\!/_T \cdot [Q^- \Delta t + Q^+ (T - \Delta t) + \\ q^- \tau + q^+ (T - \tau)], \end{gathered} \tag{6}$$

where Q^-, Q^+ – flow rates in the initial cross-section for the previous and current ten days; q^-, q^+ – similar average ten-day lateral inflows in the section; Δt, τ – the lag time of the main and lateral inflow to point X; T – ten days (c).

Since the lateral inflows are, as a rule, much less than the main inflow and the lag time is much less than Δt, equation (6) can be simplified as follows:

$$Q^X \approx {}^1\!/_T \cdot [Q^- \Delta t + Q^+ (T - \Delta t)] + q^+. \tag{7}$$

The lag time of the changed flow can be determined by the average current velocity in the section according to the Chezy equation: $\Delta t = {}^L\!/_\upsilon$, where L is a distance between the cross-sections.

Models for complex management of the Angara cascade hydroelectric plants operation include many simulation and optimization models. The main components of the metamodel designed to study the HPP operation management are shown in Fig. 5. To consider the HPP cascade it is necessary to develop the metamodels for each HPP and for the entire cascade.

Simulation models determine all the necessary parameters, criteria and constraints for water-energy calculations based on hydrological, water-management and energy models. They make it possible to carry out end-to-end calculations for the entire period of the statistics collection (since 1899) or for individual studied periods (for low-water and high-water periods, since the beginning of HPP operation, since the year of introduction/changes in the Rules for Water Resource Management (RWRM), etc.), as well as to calculate model inflows. Water flows through the HPP cross-sections are determined not only by reservoir operating curves but also by special algorithms taking into account prognostic water availability indices.

The construction of simulation models to study different HPP operating conditions requires that the flow rate through the HPP cross-sections at each considered period be uniquely determined. When modeling the natural regimes of the Irkutsk hydropower plant, we determine the flow rate by the family of correlation curves between the level of Lake Baikal and the level of the upper reach of the dam. When modeling the winter operation of the Bratsk HPP, it is necessary to set its flow rate so that the total capacity of all HPPs of the Angara-Yenisei cascade has a certain guaranteed value. The summer operation of the Bratsk HPP should provide the flow rate for navigation in the Lower Angara, as well as the filling of the Ust-Ilimsk and Boguchany reservoirs and subsequent maintenance of their levels.

Multi-criteria optimization models include several models ranked by priority of optimization criteria for the use of water resources by different water users, provided their requirements are met with given normative reliability. The main modeling parameters are a set of several reservoir operating curves that take into account the specifics of individual water users. Their internal parameters can vary. The formal description of the models and the notations they contain are given below:

$t=(y,d)$ – discrete time, y – year,
d – ten days (month);
P_t – actual inflow into the reservoir at time t;
P_t^* – predicted inflow;
q_t – the flow rate through the HPP cross-sections;
h_t^+ – level of the upper reach at the end of the period $[t, t+\tau]$;
h_t^- – level of the lower reach;
Δh_t – head;
N_t – HPP power;
E_t – electricity output over the period $[t, t+\tau]$, where τ is period duration;

$\omega_t(k,\theta_k)=\{q_t, h_t^+, h_t^-, \Delta h_t, N_t, E_t, \theta_t^{\omega}\}$ is a set of basic calculated parameters that are determined by the function $\omega_t(k,\theta_k)=F^{\omega}(D_k(\theta_k), P_t, P_t^*, h_{t-1})$ over the time interval $[t, t+\tau]$; θ_t^{ω} are additional parameters considering detailed operating parameters (for example, efficiency, total and effective heads, loading of hydropower units, etc.); $D_k(\theta_k)$ is the k-th reservoir operating

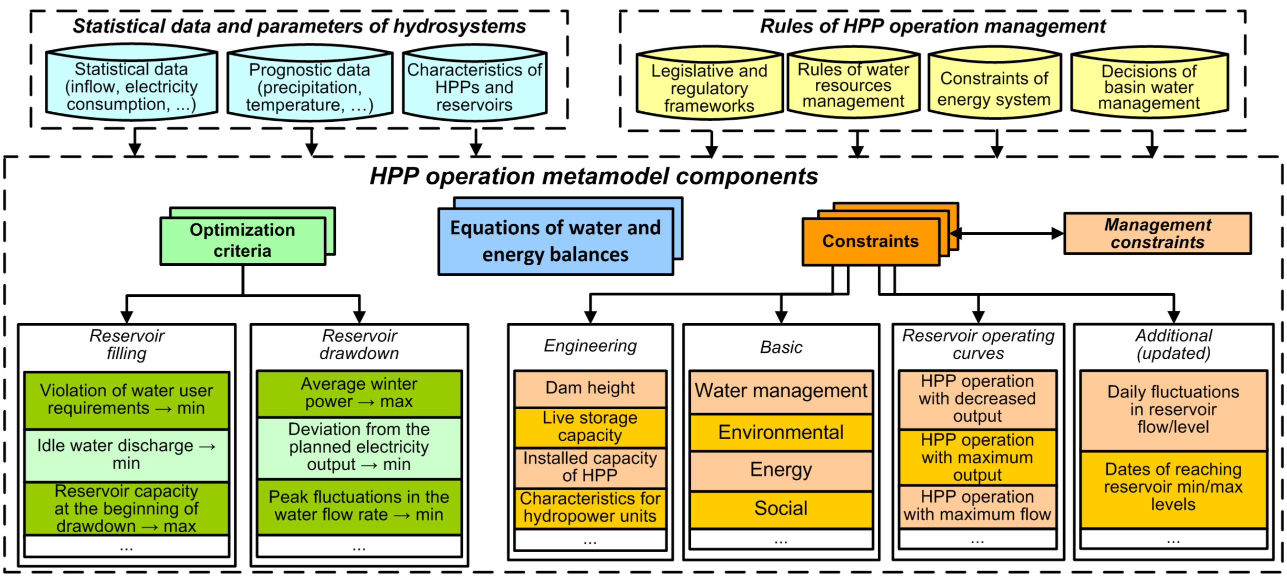


Fig. 5. The structure of the main components of the HPP operation metamodel

curve with a set of internal parameters θ_k from a set of the studied $\overline{D} = \{D_k(\theta_k) : k = \overline{1,K}; \theta_k \subset \overline{\theta}_k\}$;

$\Omega_{t_1 \to t_2}(k, \theta_k) = \left(\{\omega_t(k, \theta_k), (P_t, P_t^*) : t \in [t_1, t_2]\}\right)$ – end-to-end calculations of operating conditions for the period $[t_1, t_2]$;

$\overline{\Omega}_{t_1 \to t_2} = \{\Omega_{t_1 \to t_2}(k, \theta_k) : k = \overline{1,K};\ \theta_k \subset \overline{\theta}_k\}$ – matrix of solution options for all the reservoir operating curves and variation in the internal parameters from the set $\overline{\theta}_k$;

$\Lambda = (\lambda^A, \lambda^B, \lambda^E, \lambda^T, \lambda^R, \lambda^S)$ – vector of availabilities after meeting: A – operational and technical constraints, B – water withdrawal requirements, E – energy requirements; T – water transport requirements; R – fisheries requirements; S – territory non-flooding requirements;

$\Lambda\ (k, \theta_k) = F^{\Lambda}(\Omega_{t_1 \to t_2}(k, \theta_k))$ – function for determining the availability at a time interval $[t_1, t_2]$ and in the reservoir operating curve $D_k(\theta_k)$.

The main objective is to simultaneously maximize the vector of criteria:

$$(\lambda^A, \lambda^B, \lambda^E, \lambda^T, \lambda^R, \lambda^S) \to \max(\overline{\Omega}_{t_1 \to t_2}) \quad (8)$$

$$\Lambda_i \geq \Lambda_i^{\min} : i = \overline{1, K^{\Lambda}}, \quad (9)$$

where the magnitude $\Lambda_i^{\min}$ depends on the selected water user, for example, according to normative indices, the normal water consumption by the number of uninterrupted years is $\Lambda_1 \geq 95$ for water supply, $\Lambda_4 \geq 85$ for water transport, and $\Lambda_5 \geq 75$ for fishery.

The sequences of ranking the criteria by water user determine different options of HPP water resources management.

The specific feature of the calculation of the Bratsk HPP operating conditions is simultaneous consideration of the basic parameters of three (Bratsk, Ust-Ilimsk, and Boguchany) HPPs. Moreover, when calculating the average winter power of the Angara-Yenisei cascade, it is necessary to take into account the Yenisei cascade operation.

When solving problem (8)–(9), a subset of the matrix (corresponds to the Pareto set) is formed, from which the most acceptable solutions are selected.

For the energy option, the sequence of priorities of criteria (9) will have the form:

$$(\lambda^A, \lambda^B, \lambda^E, \lambda^T) \to \max(\overline{\Omega}_{t_1 \to t_2}), \quad (10)$$

For the transport option, this sequence will have the form:

$$(\lambda^A, \lambda^B, \lambda^T, \lambda^E) \to \max(\overline{\Omega}_{t_1 \to t_2}), \quad (11)$$

In the considered statements, the priorities of the first level are strict compliance with technical and operational constraints and water intake requirements. As a rule, these constraints can be included in each considered reservoir operating curve. Then, generally, the maximization of the availability criteria (11) can be written as follows:

$$(\lambda^E, \lambda^T, \lambda^R, \lambda^S) \to \max(\overline{\Omega}_{t_1 \to t_2}) \quad (12)$$

Some regulation options can be of priority only in certain periods. For example, the priority of reducing the risks of inundation of Irkutsk during periods of increased flow through the hydrosystem or the priority of permissible fluctuations in reservoir water levels under daily and weekly regulation during the periods of fish spawning. These priorities and limitations can be taken into account in problem (8)–(12), the solution to which forms a sustainable option for water resources management in the Angara river basin. A specific feature of the model is the possibility of studying the operating conditions not only throughout the full retrospective period but also at any randomly given time.

In practice, problems (10)–(12) are solved by specialized methods designed to optimize the cascade HPP operating conditions, which are formed based on the long-term reservoir operating curves. The standards established to meet the requirements of water users are determined by the Methodological Instructions on the Development of Reservoir Management Rules.

IV. Formation of long-term scenarios of water inflows into the HPP reservoirs

The reservoir operating curves currently used to manage the HPP operation are based on the statistical characteristics of inflows and allow reservoir levels to be managed according to the current total inflows and achieved water levels in each reservoir. They, however, do not allow long-term planning of water users and consumers' operation. In this regard, an important condition for planning is the development of future water inflow scenarios.

At present, the practice of the HPP operation involves along with the reservoir operating curves, the series of statistical hydrological indices and water availability forecasts provided by the Meteorological Office for a period of up to 1–3 months. As already noted, this does not meet the current needs of water and energy organizations that carry out long-term management and planning of the operation. Furthermore, due to global and regional climate change, the use of meteorological statistics alone for predictive water availability assessments becomes inefficient. Given the significant advances in the development and use of global climate models over the past decades, it seems appropriate to use them for long-term water availability assessments for a period of up to one year. One such model is the global climate model CFS-2 (Climate Forecast System) developed by the Environmental Modeling Center (EMC), a member of the international organization National Centers for Environmental Prediction (NCEP) [31]. This model is used daily to update an ensemble (set) of forecasts of the state of the atmosphere and the ocean with a time interval from several hours to 9 months for the entire globe. The ensemble approach used in the global

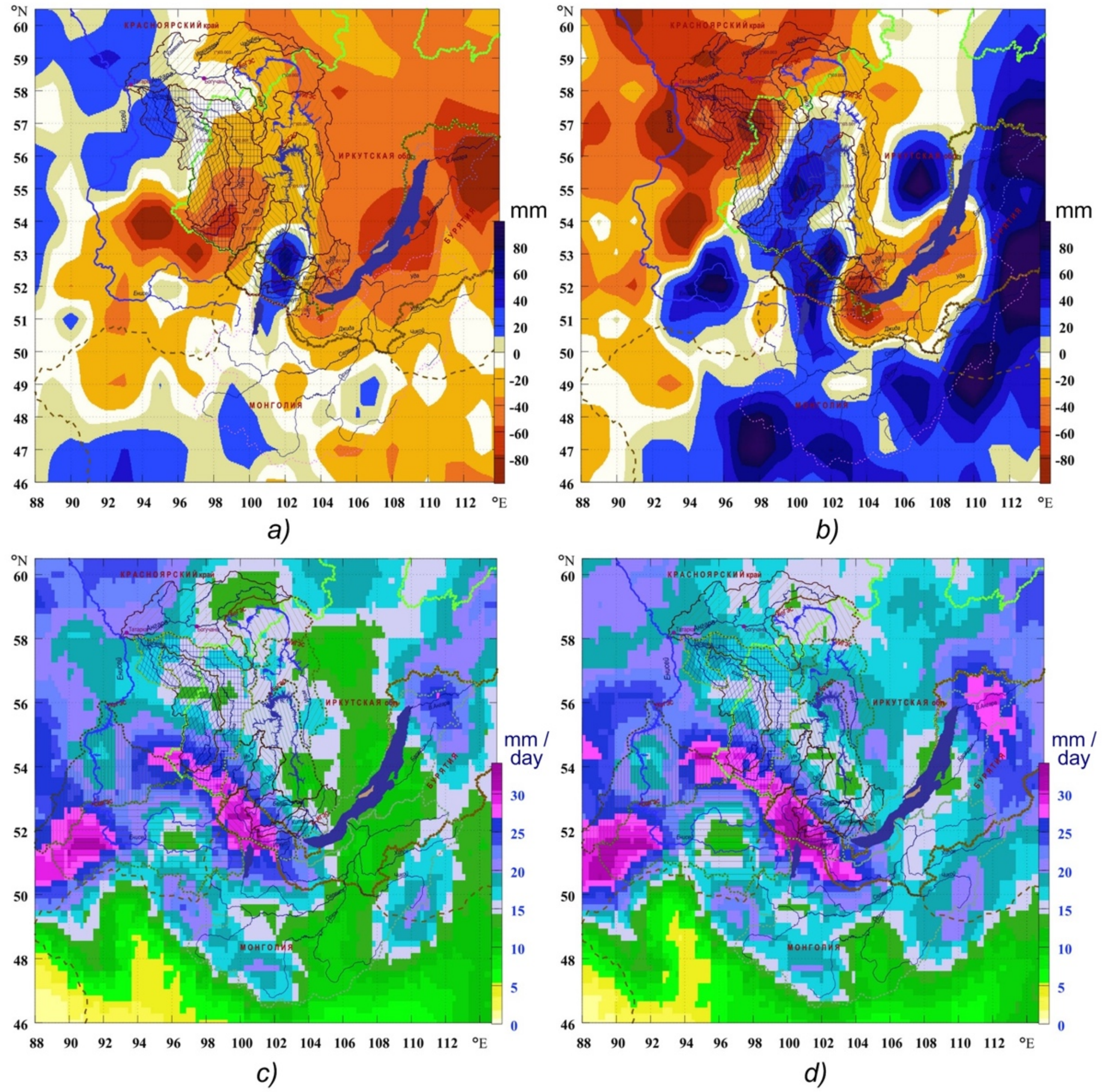


Fig. 6. Examples of anomalies in the Angara reservoir catchment basins: deviation of average summer precipitation in 2014–2017 compared to those in 1996–2013 (a); summer precipitation anomalies in 2018 (b); prognostic indices of precipitation intensities in June (c) and July (d) in 2019 (based on the 10 forecast ensembles of the CFS-2 model).

climatic model allows the probabilistic estimations of the atmosphere state to be formed for a long term.

A research team of the Melentiev Energy Systems Institute SB RAS has developed special components in the GeoGIPSAR system for monitoring, collection, and processing of modeling results. These components make it possible to quickly generate long-term estimates of precipitation, temperatures, pressure, and geopotential in the basins of Lake Baikal, the Angara and Yenisei rivers and periodically update them (weekly, every ten days, monthly, quarterly). Examples of an analysis of the climatic situation in the basins of Lake Baikal and Angara reservoirs in the past period and estimated data of the global models are shown in Fig. 6. The Figures show the estimated data of the global climatic model CFS-2 for the considered region on the anomalies of precipitation and temperature for the period from May to August 2019. The map of temperature anomalies in July-August shows a high probability of increased water for the basins of Lake Baikal and the Angara river and average water in the Yenisei basin.

The processed data of the forecast ensembles of meteorological parameters are used to make estimations of

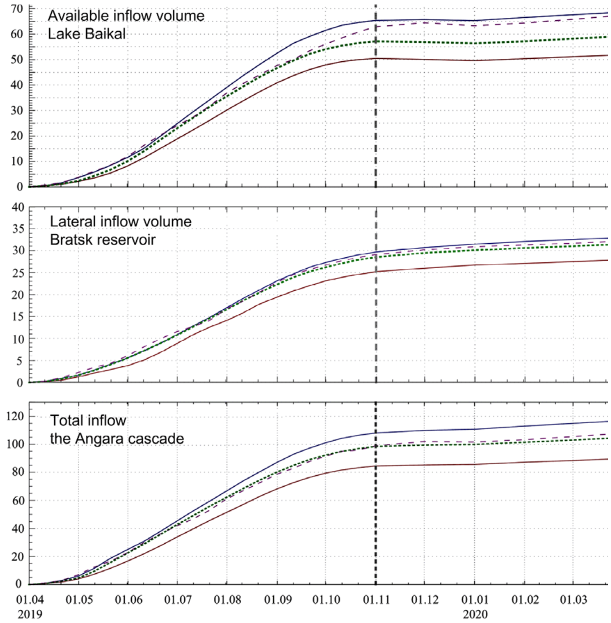


Fig. 7. An example of three forecast scenarios of available water inflow into Lake Baikal (a), lateral inflow into the Bratsk reservoir (b) and total inflow into the Angara HPP cascade (c) for the 2019–2020 water year.

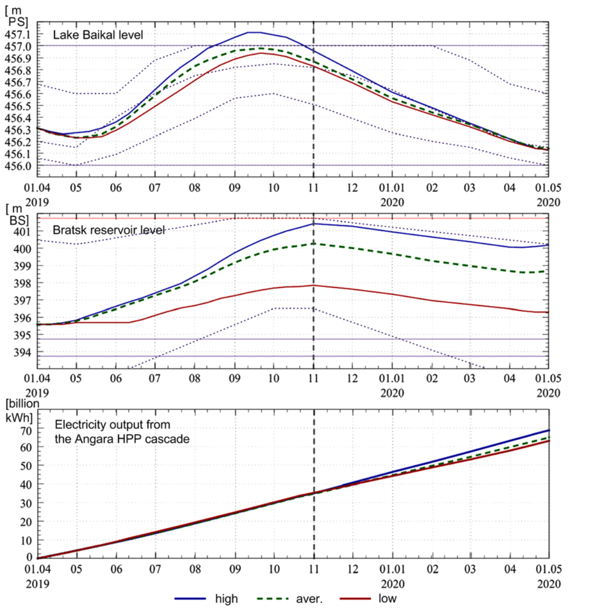


Fig. 8. Modeling of the levels of Lake Baikal, the Bratsk reservoir, and electricity output from the Angara cascade of hydropower plants for the 2019–2020 water year under different inflow scenarios.

the inflows into the cascade reservoirs in the form of ranges of probability distributions. The final prognostic scenarios are determined by an automated procedure including components of a search for analog years, rejection of low-probability events, processing of regression relationships between the meteorological indices and flows in rivers, and refinement of their boundaries using the experts' estimations made with other models [32–35]. Due to the considerable global changes in the regional climate, the study does not consider the technique for the selection of optimal prognostic models based on the machine learning methods, which is related to the need to verify their efficiency based on both retrospective and forecast samples.

Figure 7 shows an example of three scenarios of water inflow into Lake Baikal, the Bratsk reservoir, and the entire Angara HPP cascade for the coming water year, which determines the boundaries of their changes by the total indices.

V. Modeling results

Based on the long-term forecast scenarios of inflows

Table 1. Operating conditions of the Irkutsk HPP (Lake Baikal) – average water availability scenario.

Date	Availablei nflow, m^3/s	Flow through HPP, m^3/s	**Level of Lake Baikal, m PS**	Water level near dam, m PS	Level of the lower reach, m PS	**Live capacity of reserv., km^3**	Gross head, m	Capac. utilizat. factor, %	Availab. power, MW	**Calc. average power, MW**	**Calc. electricity output, mil. kWh**
01.05.2019	2900	1800	**456.23**	455.61	426.31	**21.9**	29	72	662.4	**478**	**355**
01.06.2019	4900	1800	**456.32**	456.01	426.04	**24.6**	30	65	662.4	**430**	**310**
01.07.2019	4800	1900	**456.58**	456.27	426.24	**32.9**	30	72	662.4	**475**	**354**
01.08.2019	4100	2600	**456.83**	456.20	426.95	**40.6**	29	97	662.4	**643**	**479**
01.09.2019	2900	2700	**456.96**	456.30	427.01	**44.6**	29	99	662.4	**657**	**473**
01.10.2019	1200	2400	**456.97**	456.40	426.74	**45.0**	30	89	662.4	**592**	**440**
01.11.2019	-120	1700	**456.87**	456.57	426.03	**41.8**	31	65	662.4	**433**	**311**
01.12.2019	-180	1700	**456.72**	456.39	426.03	**37.1**	30	66	662.4	**435**	**324**
01.01.2020	300	1700	**456.56**	456.20	426.03	**32.0**	30	65	662.4	**433**	**322**
01.02.2020	390	1700	**456.44**	456.06	426.03	**28.3**	30	65	662.4	**433**	**291**
01.03.2020	380	1800	**456.34**	455.85	426.15	**25.1**	30	68	662.4	**452**	**336**
01.04.2020	900	1900	**456.22**	455.53	426.23	**21.3**	29	70	662.4	**462**	**333**
01.05.2020	–	–	**456.14**	–	–	**18.8**	–	–	–	–	–
Average indices by season											
Summer	3470	2200	**456.65**	456.13	426.55	**34.9**	29.5	82	662	**545**	**2410***
Winter	280	1750	**456.53**	456.10	426.08	**30.9**	30.0	67	662	**440**	**1920***
Yearly	1870	1980	**456.59**	456.12	426.32	**32.9**	29.8	74	662	**490**	**4330***

* – total indices

Table 2. Operating conditions of Bratsk HPP – average water availability scenario.

Date	Total inflow, m^3/s	Lateral inflow, m^3/s	Flow through HPP, m^3/s	**Levels of reserv., m BS**	Level of the lower reach, m BS	**Live capacity of reserv., km^3**	Gross head, m	Capac. utilizat. factor, %	Availab. power, MW	**Calc. average power, MW**	**Calc. electricity output, mil. kWh**
01.05.2019	3400	1500	2200	**395.78**	295.87	**18.0**	101	45	4226	**2018**	**1503**
01.06.2019	3700	2000	2200	**396.46**	296.24	**21.2**	101	45	4249	**2045**	**1473**
01.07.2019	4100	2200	2600	**397.24**	296.39	**25.0**	102	53	4290	**2383**	**1774**
01.08.2019	4800	2100	2700	**398.06**	296.43	**29.0**	103	55	4363	**2491**	**1854**
01.09.2019	4200	1500	2700	**399.16**	296.44	**34.6**	103	56	4494	**2536**	**1826**
01.10.2019	3200	900	2600	**399.92**	296.38	**38.5**	104	53	4500	**2406**	**1781**
01.11.2019	2060	360	2600	**400.27**	296.39	**40.4**	104	54	4500	**2445**	**1761**
01.12.2019	1950	250	2600	**400.01**	296.41	**39.0**	103	55	4500	**2475**	**1841**
01.01.2020	1890	190	2600	**399.67**	296.43	**37.2**	103	56	4430	**2512**	**1869**
01.02.2020	1860	160	2500	**399.26**	296.34	**35.1**	103	51	4381	**2304**	**1549**
01.03.2020	1960	160	2500	**398.97**	296.19	**33.6**	102	52	4364	**2362**	**1757**
01.04.2020	2500	600	2500	**398.67**	295.94	**32.1**	103	51	4397	**2297**	**1654**
01.05.2020	–	–	–	**398.68**	–	**32.2**	–	–	–	–	–
Average indices by season											
Summer	3900	1700	2500	**397.77**	296.29	**27.7**	101.8	51	4354	**2310**	**10210***
Winter	2040	290	2550	**399.48**	296.28	**36.2**	103.2	53	4429	**2400**	**10430***
Yearly	2970	990	2530	**398.62**	296.29	**32.0**	102.5	52	4391	**2360**	**20640***

* – total indices

into reservoirs, using the above system of models, the long-term operating conditions of individual hydropower plants and the entire Angara cascade were modeled.

The study on the long-term HPP operation involved the determination of average monthly discharges through the hydrosystems, levels of upper and lower reaches, and live capacities of reservoirs at the beginning of each month. This provides more informed planning of operation of power generating companies and the System Operator in the coming water year, including summer and winter seasons. Depending on the long-term scenario of water availability, the calculated scenarios make it possible to assess the expected electricity output and the average used power from HPPs, other HPP operating parameters (head, capacity utilization factor), to form prospective energy balances in the energy system, and to determine the expected load of thermal power plants.

Tables 1, 2 and Fig. 8 present the results of modeling the long-term operation of the Irkutsk and Bratsk HPPs for the water management year 2019–2020 for the average water availability scenario characterized by the highest probability as of April 2019.

As can be seen from Fig. 8, under the high water availability scenario, for Lake Baikal there is a risk of

Table 3. Power (MW) and electricity output (million kWh) from the Angara HPP cascade under different inflow scenarios.

Inflow scenario	Average										High		Low	
HPP	Irkutsk HPP		Bratsk HPP		Ust-Ilimsk HPP		Boguchany HPP		**Angara Cascade**		Angara cascade		Angara cascade	
Value / Date	Average power (AP)	Electricity output (EO)	AP	EO	AP	EO	AP	EO	AP	EO	AP	EO	AP	EO
01.05.2019	478	**355**	2018	**1503**	1997	**1483**	1739	**1299**	6232	**4640**	5920	**4263**	5849	**4211**
01.06.2019	430	**310**	2045	**1473**	2112	**1521**	1931	**1389**	6518	**4693**	6094	**4533**	6462	**4818**
01.07.2019	475	**354**	2383	**1774**	2277	**1694**	1931	**1436**	7067	**5257**	6627	**4770**	7120	**5126**
01.08.2019	643	**479**	2491	**1854**	2302	**1713**	1931	**1436**	7368	**5482**	7193	**5354**	7068	**5259**
01.09.2019	657	**473**	2536	**1826**	2301	**1658**	1931	**1389**	7424	**5346**	7456	**5546**	7269	**5411**
01.10.2019	592	**440**	2406	**1781**	2153	**1594**	1791	**1325**	6942	**5141**	7510	**5405**	7404	**5330**
01.11.2019	433	**311**	2445	**1761**	2105	**1516**	1720	**1239**	6702	**4826**	7033	**5208**	6964	**5155**
01.12.2019	435	**324**	2475	**1841**	2132	**1587**	1735	**1291**	6777	**5043**	7693	**5539**	6065	**4366**
01.01.2020	433	**322**	2512	**1869**	2169	**1614**	1759	**1309**	6872	**5114**	7749	**5764**	6125	**4557**
01.02.2020	433	**291**	2304	**1549**	2241	**1506**	2005	**1347**	6982	**4693**	7448	**5542**	6223	**4628**
01.03.2020	452	**336**	2362	**1757**	2272	**1690**	2023	**1505**	7108	**5288**	7967	**5353**	6325	**4249**
01.04.2020	462	**333**	2297	**1654**	2283	**1644**	2049	**1475**	7091	**5105**	7944	**5911**	6443	**4793**
Average (MW) and total (million kWh) indices by season														
Summer	545	**2410**	2310	**10210**	2190	**9660**	1875	**8270**	6930	**30560**	6800	**29870**	6860	**30160**
Winter	440	**1920**	2400	**10430**	2200	**9560**	1880	**8170**	6920	**30070**	7640	**33320**	6360	**27750**
Yearly	490	**4330**	2360	**20640**	2190	**19220**	1880	**16440**	6920	**60630**	7220	**63190**	6610	**57900**

exceeding the top of conservation pool (457 m PS) by 10 cm, accompanied by increased flows through the hydrosystem and idle discharges (up to 500 m3/s). The other HPPs of the Angara cascade will have quite favorable conditions for operation, which do not violate the current rules of regulation under all water availability scenarios in the considered period. Under average water availability, all reservoirs, except for the Bratsk one, can be filled up to the levels close to the top of the conservation pool. The available storage capacity of the Bratsk reservoir increases by 14–20 km3 (the last value – for the scenario of high water availability) and for the first time in recent years it is possible to provide the reserves of long-term cascade regulation which will increase the overall stability of the water and energy system operation.

Table 3 shows the estimated electricity and power output from the Angara cascade under different inflow scenarios. The average winter power of the cascade in the case of average water availability will be 6900 MW, under high – 7600 MW, and under low – 6300 MW. The estimated annual electricity output is 60600, 63200 and 57900 million kWh, respectively. Thus, depending on the expected water availability conditions in the coming period, the range of changes in the average winter power of the Angara HPP cascade in the considered period can amount to 1300 MW, and electricity output – to 5300 million kWh.

After updating the expected water availability indices in the first ten-day period of September, given the actual hydrological situation in the Angara and Lake Baikal basins, the achieved marks of reservoir filling, forecast of the Meteorological Office for September and the data of the global climate model, the most probable scenario of inflow for the upcoming autumn-winter and spring season (till May 1 of the next year) can be formed and, on its basis, proposals on efficient operating conditions of the Angara HPP cascade can be prepared. These proposals can be used by the System Operator to make up (specify) the prospective energy balances of power and electricity and to plan the load of thermal power plants in the electric power system of Siberia.

VI. Conclusion

The proposed system of models makes it possible to comprehensively study the efficient use of water resources of the Angara basin and to estimate long-term operating conditions of the Angara HPP cascade, given the water and energy requirements, as well as the impact of natural, climatic and socio-economic factors.

The disadvantage of the modeling methodology based on the long-term forecast water availability scenarios is the probabilistic nature of quantitative estimations. Since it is so far impossible to uniquely make the long-term water availability forecasts for more than 10 days ahead, it is additionally planned to develop a special method of "adaptive management" to improve the efficiency of decisions to be made. This method will be aimed at selecting the management of water flows through hydropower plants, minimizing the risks for each estimated period with periodic (monthly) adjustment of long-term scenarios in the case of significant changes in their probabilities.

The majority of modern methods designed to manage the long-term HPP operation (for the period of more than 3 months) are based on the statistical information of the previous period and do not use other prognostic inflow indices. This leads to a decrease in the efficiency of the HPP operation and an increase in the risk of violating the requirements of water users, especially in low-water and high-water periods. In this regard, given the global and regional climate change in the basins of the Angara river and Lake Baikal in the last two decades, it appears important to build the periodically updated hydrological statistics of various duration.

The developed structure of the HPP operation metamodel includes the knowledge base of the model components and the procedure for the synthesis of individual models. This allows a comprehensive study of the HPP cascade operation, taking into account different approaches, both traditional (based on the reservoir operating curves) and new ones (considering the data of global climate models), which improves the quality of decisions to be made.

The use of the system of models to assess the long-term operating conditions of the Angara cascade of hydropower plants makes it possible to identify possible risks in the operation of the water management system of the Angara basin and the electric power system of Siberia in advance.

Acknowledgements

The research is supported by the grant of the Russian Foundation for Basic Research and the Government of the Irkutsk region (project №17-47-380005 p_a)

References

[1] Gvozdev D.B., Kurbatov A.P. Problems of the Siberian HPP operation management in a new economic environment, *Electrical Stations*, No. 3, p. 62-67, 2004, (in Russian).

[2] Nikitin V.M., Abasov N.V., Berezhnikh T.V., Osipchuk E.N. The Angara-Yenisei HPP cascade under a changing climate, *Energy Policy*, Issue 4, p.. 62-71, 2017, (in Russian).

[3] Basic rules for the use of water resources in the Angara HPP cascade reservoirs (Irkutsk, Bratsk, and Ust-Ilimsk) . - M: Ministry of Land Reclamation and Water Resources of the RSFSR, p. 64, 1988, (in Russian).

[4] Finalization of draft rules for the use of water resources of the Angara HPP Cascade reservoirs. Draft "Rules for the Use of Water Resources of the Bratsk Reservoir on the Angara River" - M: FAWR MNR, p. 156, 2013, (in Russian).

[5] Abasov N.V., Bolgov M.V., Nikitin V.M., Osipchuk

E.N. Level regime regulation in Lake Baikal, *Water Resources.* Vol. 44, Issue 3, 2017. P. 537-546. DOI: 10.1134/S0097807817030022, (in Russian).

[6] Bychkov I.V., Nikitin V.M. Water-level regulation of lake Baikal: Problems and possible solutions , *Geography and Natural Resources*. Vol. 36, Issue 3, 2015. P. 215-224. DOI: 10.1134/S1875372815030014, (in Russian).

[7] Nikitin V.M., Saveliev V.A., Berezhnikh T.V., Abasov, N.V. Hydroenergy Problems of Lake Baikal: Past and Present, Region: Economics and Sociology, No. 3 (87). pp. 273-295, 2015, (in Russian).

[8] Asarin A.E., Bestuzheva K.I. Water and energy calculations, M.: *Energoatomizdat*, p. 223,1986, (in Russian).

[9] Tsvetkov E.V., Alyabysheva T.M.; Parfenov L.G. Optimal operating conditions of hydroelectric plants in electric power systems, M.: *Energoatomizdat*, p. 304, 1984, (in Russian).

[10] Filippova T.A. Optimization of power flows of the hydropower units at hydroelectric plants, M.: Energy, p. 208, 1981, (in Russian).

[11] Kritsky S.N., Menkel M.F. Hydrological foundations of the river runoff management M.:*Nauka*, p. 250, 1998 (in Russian).

[12] Gjelsvik A., Mo B., and Haugstad A. Long- and Medium-term Operations Planning and Stochastic Modelling in Hydro-dominated Power Systems Based on Stochastic Dual Dynamic Programming. Handbook of Power Systems I, Energy Systems, S. Rebennack et al., *Springer-Verlag, Berlin*, p. .33-55, 1998.

[13] Keppo J. Optimality with Hydropower System. Power Engineering Review, IEEE, vol. 22, N 6, 2002. – 57p.

[14] Pereira M., Campodonico N., Kelman R. Long-term Hydro Scheduling based on Stochastic Models, *Proceeding of EPSOM Conference, Zurich*, p. 22. 1998

[15] Nunes T.H.C., Galvao C.O., Rego J.C. Rule curve for seasonal increasing of water concessions in reservoirs with low regularized discharges, RBRH, Porto Alegre, v. 21, n. 3, 2016. P. 493-501. http://dx.doi.org/10.1590/2318-0331.011615146.

[16] Ahmadianfar I, Adib A, Taghian M. Optimization of fuzzified hedging rules for multipurpose and multi-reservoir system, *Journal of Hydrologic Engineering*, 2015. 21(4):05016003. – 10 p., doi: 10.1061/(ASCE)HE.1943-5584.0001329.

[17] Cheong T. S., Ko I., Labadie J. W. (2010) Development of multi-objective reservoir operation rules for integrated water resources management, Journal of Hydroinformatics (2009) 12 (2). P. 185-200. https://doi.org/10.2166/hydro.2009.054

[18] Specific features of Russia's hydropower industry operation under changing external conditions (on the example of the Volga-Kama cascade of hydropower plants). Ed. by prof. A.Yu. Alexandrovsky and Corr. Member of RAS V.V. Klimenko, M: PH *Energy*, p.169, 2016, (in Russian).

[19] Water and energy regimes of hydroelectric plants in the context of climate change. Ed. by Yu.S. Vasilieva, St. Petersburg: Polytechnic University, 274 p., 2017, (in Russian).

[20] Bednaruk S.E., Motovilov Yu.G. Information support technology for the reservoir cascade management, Hydraulic engineering construction, No. 7, p.22-35., 2017, (in Russian).

[21] Abasov N.V., Chernyshov M.Yu., Osipchuk E.N. Application of the metamodelling technology to manage the HPP technological modes, *Vestnik BSU*, Ser. Mathematics and informatics, Issue 9, part 2. 2014. P.45-52., (in Russian).

[22] Osipchuk E.N., Abasov N.V. Metamodelling technology for the study of HPP operating conditions, *Proceedings of XVIII Baikal All-Russian Conference "Information and mathematical technologies in science and management". Part III*. - Irkutsk: ISEM SB RAS, p. 274-280., 2013, (in Russian).

[23] Abasov N.V., Berezhnyh T.V., Reznikov A.P. Long-term forecast of environment-related factors of the energy industry in the information-forecasting system GIPSAR, *Proceedings of the Russian Academy of Sciences, Power Engineering*, No. 6, pp. 22-30., (in Russian)., 2012.

[24] Abasov N.V. The GeoGIPSAR system of long-term forecasting and analysis of environment-related factors of the energy industry, Proceedings of the International Meeting of APN (MAIRS/NEESP/SIRS) "Extreme manifestations of global climate change in North Asia": *Enviromis*, p.63-66, 2012.

[25] Klir G., Elias D. Architecture of Systems Problem Solving. *Plenum Press,* New York, p354, 1985.

[26] Atkinson C., Kühne Th. The Essence of Multilevel Metamodeling, *Proceedings of UML* 2001 – The Unified Modeling Language. Modeling Languages, Concepts, and Tools: *4th International Conference*, V. 2185 of LNCS, Toronto, Canada, Springer, p. 19–33, 2001.

[27] Jeusfeld M.A., Jarke M., Mylopoulos J. Metamodeling for Method Engineering. Cambridge, *MA: MIT Press*, 424 p. 2009.

[28] Gigch. J.P. System Design Modeling and Metamodeling. – New York: *Plenum Press*, p. 453 , 1991.

[29] Gachenko, A.S., Hmelnov, A.E., Abasov, N.V., Osipchuk, E.N. Technology of flood water zones

modeling in downstream pool of hydroelectric power station at strong flow through its water abstraction points, *CEUR Workshop Proceedings*, vol. 2033, pp. 252-256. 2017.

[30] Manning R. On the flow of Water in Open Channels and Pipes. *Transactions Institute of Civil Engineers of Ireland*, Dublin, vol. 20, 1891. P. 161-209.

[31] The NCEP Climate Forecast System. Available at: http://cfs.ncep.noaa.gov (accessed on 10.10.2019).

[32] Berejnykh, T., Abasov, N. The increasing role of long-term forecasting of natural factors in energy system management, International Journal of Global Energy Issues, Vol. 20, Issue 4, P. 353-363. DOI: 10.1504/IJGEI.2003.004408. 2003.

[33] Abasov N.V., Berezhnykh T.V, Vetrova V.V. Long-term forecasting of Angara cascades' hydropower potential, *Proc. of International Conf. "Water: the blue gold"*, Dunedin, New Zealand, p. 226-227. 2010.

[34] Berezhnykh T.V., Marchenko O.Yu., Abasov N.V., Mordvinov V.I. Changes in the summertime atmospheric circulation over East Asia and the formation of long-lasting low-water periods within the Selenga river basin, *Geography and Natural Resources*. Vol. 33, No. 3, p. 223-229. 2012.

[35] Abasov N.V., Berezhnykh T.V., Vetrova V.V., Marchenko O.Yu., Osipchuk E.N. Analysis and Forecasting of the Baikal Region Hydropower Potential under the Conditions of Variable Climate, *Risks and Opportunnities of the Energy Sector in East Siberia and the Russian Far East*, Berlin, p. 173-186, 2012

Nikolai Abasov – graduated from the Moscow Physical Technical Institute in 1978. Currently he is a Senior Engineer at Melentiev Energy Systems Institute of SB RAS. His research interests include the development new techniques and methodologies to improve the efficiency of hydroelectric system in a changing climate.

Viacheslav Nikitin – graduated from Sankt-Petersburg Technical University, specialty Hydro Power Plants in 1977. Candidate of Economic Sciences (1982), Doctor of Technical Sciences (1992). Head of Hydropower and Water Management Systems Laboratory of the Melentiev Energy Systems Institute of Siberian Branch of Russian Academy of Sciences. His research interests are problems of management of Hydro Power Plants (HPP) and HPP cascades as part of Water and Energy Systems.

Evgeny Osipchuk – graduated from Institute of Information Technologies and Modeling of Irkutsk State Transport University, specialty Software Engineer (2009). Candidate of Technical Sciences (2014). Researcher of Hydropower and Water Management Systems Laboratory of the Melentiev Energy Systems Institute of SB RAS. His research interests are long-term regimes modeling of HPP cascades based on water and energy system constraints with various optimization criteria.

Algorithms For Considering The Temperature Of Overhead Conductors In The Calculation Of Steady States Of An Electrical Network

Oleg Voitov, Ekaterina Popova*, Ludmila Semenova

Melentiev Energy Systems Institute of Siberian Branch of Russian Academy of Sciences, Irkutsk, Russia

***Abstract* — This paper presents an algorithm developed and implemented in software to calculate the normal steady state of an electrical network based on jointly solving a system of the nodal power balance equations using the Newton – Raphson method and the heat balance equation for overhead conductors. The algorithm allows considering the resistance of overhead conductors as a function of the magnitude of current in the conductors of various voltage levels based on the calculation of their temperature. The improved expressions for determining the coefficients of the heat balance equation for a conductor are obtained subject to the actual environment parameters (atmospheric pressure, air temperature, etc.), which were calculated by V.V. Burgsdorf and recommended by the regulatory documents for normal values of air parameters. Consideration of the actual temperature of overhead conductors also allowed improving the value of the conductor sag in the span and expanding a set of inequality constraints in the calculation of feasible steady states of electrical networks.**

***Index Terms* — conductor heat balance equation, conductor state equation, conductor sag in the span, feasible steady state, overhead line resistance, normal steady state.**

I. Introduction

The current conditions of electrical network operation give rise to new information opportunities for improving the accuracy of mathematical description of network components.

The current conditions of electrical network operation give rise to new information opportunities for improving the accuracy of mathematical description of network components.

One of the directions for improvement of the models of the electrical network components and, as a result, the parameters of its steady states is to consider the influence of the actual temperature of overhead conductors on the parameters of network components. The conductor resistance and sag in the span are highly sensitive to changes in the conductor temperature.

The temperature and resistance of conductors are known to depend on their current load and a number of environment parameters, such as wind speed and direction, air temperature and pressure, and solar radiation intensity. This dependence can be represented by the conductor heat balance equation. Dependence of the conductor sag on temperature can be represented by the conductor state equation.

Most present-day software for the calculation of electrical network steady states does not include the heat balance and conductor state equations [11, 36, 39, 40, 51-55, 66, 67] The temperature of overhead conductors in them is often set equal to either the normalized value of 20°C or the air temperature [1, 5, 10, 16] This simplification makes it impossible to consider the actual temperature condition of conductors and results in erroneous determination of the steady state parameters of electrical networks.

At the same time, numerous theoretical [2,6-8,10,12-14,43,44,59-62,64,65] and practical [3,17-22,45-48] methods have been developed to determine the conductor parameters with varying degrees of accuracy subject to the actual temperature condition. Moreover, in most cases, these methods are not considered in the existing algorithms for steady state calculation.

Note the method described in [2], in which a quadratic approximation of the conductor heat balance equation is applied to determine the conductor temperature, and the approximation coefficients must be determined for each

* Corresponding author.
Email: elen@isem.irk.ru

http://dx.doi.org/10.25729/esr.2019.02.0002
Received February 13, 2019. Revised July 7, 2019.
Accepted September 5, 2019. Available online October 31, 2019.

specific value of air temperature changing in a wide range. In this case, a large array of the coefficients for each conductor brand must be stored and processed in the computer memory, which is irrational from the software point of view.

Expressions and, for some conductors, available numerical values of the adjusting coefficients to the heat balance equation, which are difficult to determine due to the complexity of considering many unstable natural factors such as the degree of air pollution, the angles of sun rays slope and wind attack, the duration of sunny and cloudy weather, etc., are proposed in [3,6-9,12-15,27-34,49,50,59-62,64]

When determining the conductor sag in the span, in most cases its temperature in the state equation is also taken into consideration approximately. It is either set by a required value, or equated to the air temperature [3,7,14,32,37]

At present, the algorithms for calculating normal steady states in 0.4-110 kV distribution networks, given the actual temperature of overhead conductors, which is determined by numerically solving the heat balance equation as in [3], are proposed only in [7,13,63] Due to the topological features of distribution networks, the algorithms have simplifications and a limited area of application. Their application to networks of higher voltage classes requires consideration of a number of additional factors analyzed in the proposed paper.

There is also no known algorithm, besides the one developed by the authors of this paper, for calculating the feasible steady state of an electrical network, which takes into account the conductor sag in the span along with other parameters of overhead conductors.

This paper presents an algorithm implemented in the software for calculating the normal steady states of electrical networks of different voltage classes. The algorithm was developed by jointly solving a system of nodal power balance equations, which is the heart of the algorithm [40,42], and the conductor heat balance equation, which was solved analytically by the Newton method [23-26] We also propose an algorithm for calculating the feasible steady states of electrical networks by jointly solving the normal steady state equations and the conductor state equation, which is accurately solved by Cardano's formulas [38]

For the first time in the practice of calculating the feasible steady states, the conductor sag in the span is considered as an additional inequality constraint imposed on the steady state parameters, which allows expanding the list of "traditional" inequality constraints and increasing the calculation accuracy of steady feasible, optimal and heavy states of power systems, when it is necessary to calculate the state variables as accurately as possible.

The proposed algorithms for calculating the steady states of electrical networks are implemented in the certified software SDO-7 (developed at Melentiev Energy Systems Institute of SB RAS) [41] and have been extensively tested on some overhead transmission lines and calculation schemes of real power systems of various sizes in the Irkutsk region [25, 38,56,58]

II. Methodology For Calculating Steady State Of An Electrical Network

1. Determination of temperature and resistance of overhead conductors

The unit resistance of an overhead conductor subject to its temperature T_{con} is determined by the known expression:

$$r_{0\ (T_{con})} = r_{0\ (20)} \cdot [1 + \alpha_T \cdot (T_{con} - 20)] \quad (1)$$

where α_T, $r_{0\ (20)}$ is the temperature coefficient of conductor resistance and its unit resistance at $T_{con} = 20°C$.

The algorithm for calculating T_{con} suggests analytically solving the algebraically transformed "traditional" nonlinear quadratic equation of the conductor heat balance, which is recommended by the regulatory documents [9].

The algorithm for calculating T_{con} suggests analytically solving the algebraically transformed "traditional" nonlinear quadratic equation of the conductor heat balance, which is recommended by the regulatory documents [9]:

$$I_{ij} = \sqrt{\frac{[(W_l + W_{k,1,2,3}) \cdot (T_{con} - T_в)] - Q_r}{r_{0\ (T_{con})}}} \quad (2)$$

where I_{ij} is the phase current of branch ij, A; $T_в$ is the air temperature, $°C$;

$W_l = 7.24 \cdot \beta \cdot d_{con} \cdot \left[\frac{(T_{con} - T_в)/2 + 273}{1000}\right]^3$ is the radiation heat transfer coefficient, $W/(m \cdot °C)$;

$W_{k,1} = 0.16 \cdot d_{con}^{0.75} \cdot (T_{con} - T_в)^{0.3}$,

$W_{k,2} = 1.1 \cdot \sqrt{\nu \cdot d_{con}}$, $W_{k,3} = 0.55 \cdot \sqrt{\nu \cdot d_{con}}$

is the convective heat transfer coefficient at a wind speed of $v < 1.2$ m/s, $v \geq 1.2$ m/s and the wind direction perpendicular to the conductor, at $v \geq 1.2$ m/s and the wind direction along the conductor, respectively, $W/(m \cdot °C)$ $Q_r = 100 \cdot \varepsilon_П \cdot q \cdot d_{con}$ is the solar radiation power, $W/(m \cdot °C)$; d_{con} is the conductor diameter, cm; $\varepsilon_П$ is the absorption coefficient equal to the radiation coefficient $\varepsilon_П = \beta = 0.6$; q is the mean monthly total (direct plus reflected) solar radiation power taken on the basis of the observed data of meteorological stations, W/cm^2, or, in the case of their absence, assigned equal to $q = [0;0,07]$ W/cm^2 in the winter and summer periods.

As a result of algebraic transformations and replacement of the variables in expression (2): $I_{ij} = U_{ij} \big/ (\sqrt{3} \cdot Z_{ij})$, where Z_{ij}, U_{ij} is the impedance and the voltage drop magnitude in a conductor that is equal to the magnitude of difference in the vectors of nodal voltages $\left|\overline{U}_i - \overline{U}_j\right|$, Ohm, V, respectively; the initial quadratic equation (2) of form $I_{ij}(T_{con}) = f(T_{con}, T_в, Q_r, \nu)$

is transformed into the sextic equation of form $\Delta T = T_{con} - T_{в} = f(U_{ij}, T_{в}, Q_r, v, P_{в})$, which shows the dependence of difference in conductor and air temperatures on the conductor voltage drop and actual environment parameters.

It is worth noting that the environment parameters additionally include the actual value of atmospheric pressure that differs from its standard value equal to $P_{в}=760$ *mm Hg*, traditionally applied in the regulatory documents [9]

The current atmospheric pressure value can be taken into account by the mathematical transformation of the criterion equations of convective heat exchange, which are the basis for determining the convective heat transfer coefficient in the conductor heat balance equation [27,29,35,36], given their actual value of $P_{в} \neq const$

In the expanded form, the transformed heat balance equation is the transcendent and algebraic equations (3), (4) for a wind speed $v < 1.2$ *m/s* and $v \geq 1.2$ *m/s* with its direction perpendicular to the conductor:

$$\begin{aligned} &\Delta T^6 + a_5 \cdot \Delta T^5 + a_4 \cdot \Delta T^4 + a_{33} \cdot \Delta T^{3,3} + \\ &+ a_3 \cdot \Delta T^3 + a_{23} \cdot \Delta T^{2,3} + a_2 \cdot \Delta T^2 + \\ &+ a_{13} \cdot \Delta T^{1,3} + a_1 \cdot \Delta T + a_0 = 0, \end{aligned} \tag{3}$$

where

$$a_{33} = m \quad a_3 = 3b \cdot x_{np}^2 / f + b^3 + 6b^2 c + 3bc^2$$

$$a_{23} = 2mc \, ; a_2 = p + 3b^3 c + 3b^2 \cdot x_{np}^2 / f + 3b^2 c^2 \, ;$$

$$a_{13} = m \cdot x_{np}^2 / f + mc^2$$

$$a_1 = b^3 \cdot x_{np}^2 / f + 2cp + b^3 c^2 - n \cdot U_{ij}^2 / f \, ;$$

$$m = \frac{0{,}39 \cdot P_{в}^{0,5} \cdot d_{np}^{0,75} \Big/ T_{в}^{0,75}}{a}$$

$$\begin{aligned} &\Delta T^6 + a_5 \cdot \Delta T^5 + a_4 \cdot \Delta T^4 + a_3 \cdot \Delta T^3 + \\ &+ a_2 \cdot \Delta T^2 + a_1 \cdot \Delta T + a_0, \end{aligned} \tag{4}$$

where

$$a_3 = g_1 + 3b \cdot x_{np}^2 / f + 6b^2 c + 3bc^2 \, ;$$

$$a_2 = 3b^2 \cdot x_{np}^2 / f + p + 2cg_1 + 3b^2 c^2 \, ;$$

$$a_1 = g_1 \cdot x_{np}^2 / f + 2cp + g_1 c^2 - n \cdot U_{ij}^2 / f .$$

The other coefficients in (3), (4) are the same and determined as follows:

$$a_5 = 3b + 2c \, ; \; a_4 = x_{np}^2 / f + 3b^2 + 6cb + c^2 \, ;$$

$$a_0 = p \cdot x_{np}^2 / f + pc^2 - nc \cdot U_{ij}^2 / f \, ;$$

$$a = 0{,}543 \cdot 10^{-9} \cdot d_{np} \, ; \; b = 2 \cdot T_{в} + 546 \, ;$$

$$c = 1/\alpha_T - 20 + T_{в} \, ; \; f = (l_{ij} \cdot r_{0(20)} \cdot \alpha_T)^2 \, ;$$

$p = -\dfrac{60 \cdot q \cdot d_{np}}{a}$; $n = \dfrac{r_{0(20)} \cdot \alpha_T}{3a}$; x_{np} is the inductive impedance of a conductor, *Ohm/m*

At a wind speed of $v > 1.2$ *m/s* with its direction along the conductor, the coefficient g_1 in (4) is replaced with g_2, where $g_1 = b^3 + \dfrac{0.661 \cdot \sqrt{P_{в} / T_{в}} \cdot \sqrt{v \cdot d_{con}}}{a}$,

$$g_2 = b^3 + \frac{0.33 \cdot \sqrt{P_{в} / T_{в}} \cdot \sqrt{v \cdot d_{con}}}{a} .$$

Expressions (3), (4) are the higher-order equations and solved by the Newton method with the low required accuracy equal to $\xi_{\Delta T} = 10^{-9}$ given in advance.

The experimental MAPLE-program was used to investigate the structure and properties of the coefficients, roots and first derivative of the equations for a number of conductors of various brands.

The performed studies have showed that the transcendent equation (3) has five roots at any combinations of its parameters U_{ij}, $T_{в}$, Q_r, v, $P_{в}$, , the algebraic equation (4) has six roots. At all the combinations of the parameters, both equations have the only positive real root that has a physical meaning and is accepted as the solution. The results of the studies are presented in Paragraph III.1.

2. Determination of the conductor sag and length in the span of an overhead line

For the first time, the algorithm for determination of mechanical parameters of overhead line conductors (the sag and length of conductors in the span) involves solving the conductor state equation analytically as distinct from other known algorithms suggesting solving it numerically:

$$\begin{aligned} \sigma_n - \frac{E \cdot \gamma_n^2 \cdot l^3}{24 \cdot \sigma_n^2 \cdot l_{np}} = \sigma_m \frac{E \cdot \gamma_m^2 \cdot l^3}{24 \cdot \sigma_m^2 \cdot l_{np}} - \\ - \alpha \cdot E \cdot (T_{np,n} - T_{np,m}), \end{aligned} \tag{5}$$

where α, E are the temperature coefficient of the linear expansion of conductor material, degrees^{-1} and modulus the conductor elasticity, Pa, whose values are taken in accordance with the data of reference books; $l \neq l_{con}$, where l, l_{con} are the span length and the conductor length in the span, m.

The parameters with the subscript "*m*" in expression (5) correspond to the known initial climatic conditions, according to which the conductor is affected by the highest permissible tension $\sigma_m = \sigma_{perm}$. The conductor temperature is taken equal to the lowest air temperature of $T_{con,m} = T_{в,m} = -40°C$, there are no wind and icy spots. The conductor is affected by its own weight of $\gamma_m = \gamma_1$. The values of σ_{perm}, γ_1 are taken in accordance with the data of the regulatory documents.

The parameters with the subscript *"n"* correspond to the design climatic conditions, under which there are no icy spots, $v \le 1.2\,m/s$, $\gamma_n = \gamma_1$. The conductor temperature is not equal to the air temperature $T_{con,m}$ = $T_{в,m}$ and is determined by solving the conductor heat balance equation during power flow calculation.

Equation (5) is cubic with respect to σ_n and solved by Cardano's formulas, whose application makes it possible to obtain an accurate solution by meaпs of simple arithmetic operations: add, subtract, multiply, divide.

The structure and properties of equation (5) were studied by the example of a number of conductors of various brands using the experimental MAPLE-program. As a result of the studies, the equation for any combinations of its parameters proved to have a positive discriminant and three roots. In this case, in accordance with [57], among the roots of the equation there is one real root that has a physical meaning, which is taken as the solution.

After equation (5) is solved and σ_n is determined, the conductor sag and its length in the span are determined from expressions (6):

$$f_n = \frac{\gamma_n \cdot l^2}{8 \cdot \sigma_n}, \; l_{np} = l + \frac{\gamma_n^2 \cdot l}{24 \cdot \sigma_n^2}. \tag{6}$$

The experimental program was also applied to study the influence of the actual temperature of overhead conductors, which was taken into account in the state equation, on the conductor sag and its length in the span.

The findings indicate that adjustment of the sag, in comparison with the situation, when the conductor temperature in the equation was taken equal to the air temperature, is sizable and can exceed 30%. Adjustment of the conductor length in the span does not exceed 1% and can be neglected. The results of the studies are described in Paragraph III.2.

3. An algorithm for calculating the normal steady state of an electrical network

The conductor heat balance equation (2) included in the "traditional" algorithm for calculating the normal steady state of an electrical network as one of the additional points improves the accuracy of determining electrical parameters of overhead line conductors: their temperature and resistance, and hence, the steady state parameters of an electrical network.

To do this, in the proposed calculation algorithm, the Jacobian matrix elements should be adjusted by inclusion of additional components, which are a derivative of the implicit function of the conductor resistance with respect to the steady state parameters (nodal voltage magnitudes and phases):

$$\frac{\partial r_s}{\partial U_s} = -\left(\frac{\partial Wr_s}{\partial r_s}\right)^{-1} \cdot \frac{\partial Wr_s}{\partial U_s}, \tag{7}$$

where s is the branch containing an overhead line conductor. Expression (7) is a derivative of the conductor heat balance equation with respect to the steady state parameters.

The proposed improved algorithm for calculating the normal steady state of an electrical network differs from its "traditional" version in two new additional blocks: determination of the temperature and resistance of overhead line conductors by analytically solving the conductor heat balance equation (2) and calculation of the derivative of the conductor resistance with respect to the steady state parameters (7).

4. An algorithm for calculating the feasible steady state of an electrical network

The conductor state equation (5) included in the "traditional" algorithm for calculating the feasible steady state of an electrical network increases the accuracy of determining the mechanical parameters of overhead conductors: the conductor sag and its length in the span, as well as the feasible steady state parameters of an electrical network.

To determine the feasible steady state, the proposed algorithm must take into account the conductor sag as an additional inequality constraint imposed on the steady state parameters U_s:

$$f_{s,min} \le f_s \le f_{s,max}, \tag{8}$$

where $f_{s,min}$, $f_{s,max}$ are the minimum and maximum sag values.

For the functional relation $f_s(U_s)$, it is also necessary to determine the derivative of the complex function of equation (5) at each iteration of feasible steady state calculation:

$$\frac{\partial f_s}{\partial U_s} = \frac{\partial f_s}{\partial T_{con,n}} \cdot \frac{\partial T_{con,n}}{\partial U_s}, \tag{9}$$

where the first multiplier is the derivative of the explicit function $\sigma_n(T_{con,n})$ of expression (5), the second multiplier is the derivative of the explicit function $r_{0(T_{con,n})}(U_s)$ of the equation of the conductor heat balance (2) that is determined in the calculation of the normal steady state.

The developed algorithm for calculating the feasible steady state differs from its "traditional" version in three additional blocks: calculation of the normal steady state of electrical networks in accordance with the algorithm described in paragraphs *1-3*, determination of the mechanical parameters of overhead conductors by solving the conductor state equation (5) and inclusion of the complex function derivative of the conductor sag with respect to the steady state parameters (9).

III. Testing the approaches and algorithms

1. A numerical study on the properties of the conductor heat balance equation

The properties of the conductor heat balance equation were studied for some conductor brands.

Table 1 presents the values of the equation

Table 1. Roots of the heat balance equation for the AC-120/27 conductor at $I_{con,\ perrm}$ *=375A*.

v, *m/s*	U_{ij}, *V*	Values of equation roots ΔT, *°C*	$T_{con} = T_в + \Delta T$, *°C*
≤ 1.2	709.11	**46.59**; – 123.41 ± j1232.6; – 277.51 ± j443.94	66.59
= 5	684.25	**11.53**; – 2161.16; – 243.25 ± j443.64; 189.07 ± j1367,55	31.53

roots that were calculated for the *AC-120/27* conductor at the following environment parameters: $T_в = 20°C$, $Q_r = 0$, $v \le 1.2$ *m/s* and $v = 5$ *m/s* with the wind direction perpendicular to the conductor. In the calculations, the conductor length was taken equal to $l_{ij} = 2000\ m$, the current load corresponded to the maximum permissible value of $I_{con,\ perm} = 375\ A$ the table presents the values of the conductor linear voltage that correspond to $I_{con,\ perm}$ at $v \le 1.2$ *m/s* and $v = 5$ *m/s*. The equation roots selected as a solution are given in bold type.

Similar calculations performed for some other conductors of various brands at different combinations of currents (voltage drop) in the conductors and environment parameters have showed that the number and structure of the equation roots, as well as the nature of the relations themselves are preserved at any combinations of the parameters studied. In this case, the equations have a real solution at the conductor overcurrent equal to .

2. Impact of the actual temperature of conductors on their mechanical parameters

The impact of the actual temperature of overhead line conductors, which is taken into consideration in the conductor state equation ($T_{con,n} \ne T_в$), on the values of the calculated mechanical parameters: f and l_{np} in comparison with the "traditional" situation when $T_{con} = T_в$ is shown in table 2 by the example of the *AC-150/19* conductor.

Table 2. Mechanical parameters of the *AC-150/19* conductor versus its temperature.

$\Delta T = T_{con,n,i} - T_в$, °C	$\Delta f = f_{T_{np,n,i}} - f_{T_в}$, *cm*	$\Delta l = l_{T_{np,n,i}} - l_{T_в}$, *cm*
10	16	0.62
20	35	1.39
30	56	2.34
40	80	3.51
50	108	6.97

Table 3. Values of the conductor temperature and overheating, relative total active power losses.

Conditions	Heavily loaded	Lightly loaded	D of OLP, $Q_r = 0$	D of OLP, $Q_r \ne 0$
1	2	3	4	5
T_{con}, °C	62.9-95.5	40-62.9	-	-
ΔT, °C	41.9-75.5	10-37.9	-	-
$\delta\,\Delta\pi$, %	10.1-35.3	0.2-3	1.48-3.71	2.76-6.78

The calculations were performed on the assumption of no-wind conditions and absence of icy spots: $v < 1.2$ *m/s*, $\gamma_n = \gamma_1$, at an air temperature of $T_в = 20°C$ and a span length of $l = 300\ m$. The conductor temperature, which was preliminarily determined by solving the heat balance equation, changed in a range of $T_{con,n,i} = (30, 40, 50, 60, 70)°C$.

The Table presents the improved mechanical parameters Δf, Δl of the conductor as a result of the adjustment of its temperature from $Tcon,n = T_в = 20°C$ to $T_{con,n} = T_{con,n,i}$.

The data of the Table show that at the maximum overheating of the *AC-150/19* conductor above the air temperature from $T_{con,n,i} = T_в = 20°C$ to the value that is maximum permissible in terms of heating $T_{con,n,i} = 70°C$, the conductor sag improvement reaches $\Delta f = 108$ *cm* = 34.5%.

The adjustment of the conductor length in the span is negligible and is equal to $\Delta l = 7$ *cm* = 0.02%.

3. Testing of the algorithm for calculating the normal steady state of an electrical network

The improved algorithm for calculating the normal steady state of an electrical network, which takes into consideration the analytically solvable equation of the conductor heat balance, was tested on 10 real electrical networks of various dimensions in the Irkutsk Region. For testing, the results of two options of calculations were compared for each considered scheme: at a constant conductor temperature equal to the air temperature and the conductor temperature obtained by solving the heat balance equation. The calculation schemes had different current loads of overhead lines, which made it possible to divide them into two groups - heavily loaded and lightly loaded. The values of the conductor temperature for the two calculation options and the total active power losses were compared for each scheme in the first or second group.

The values of the conductor temperature and the total active power losses were compared for the air temperature ranging from *-20°C* to *+40°C*. The results of numerous calculations are compiled in Table 3, with indication of the conductor overheating values ΔT calculated as a difference in the conductor and air temperatures, the values of relative total active power losses $\delta\Delta\pi = \frac{\pi_2 - \pi_1}{\pi_1} 100$ %, where π_1, π_2 are the total active power losses in the first and second options, as well as the impact of distribution of overhead line parameters

(D of OLP) by length on the total active power losses.

The table shows that the improvement (correction) of the total active power losses owing to the consideration of the conductor temperature varies in a wide range of the values and depends on the environment parameters and the current load of conductors.

The total power losses are improved most effectively in the case of the overcurrent of conductors, whose temperature is T_{con} = (62,9 - 95,5)°C, and the overheating ΔT above the air temperature is within a range of ΔT = (41,9 - 75,5)°C. In this case, the improvement in the total active power losses is 10.1-35.3%.

The temperature of lightly loaded conductors does not exceed $T_{con} = 62{,}9°C$, and the improvement in losses is 3%.

The impact of the distribution of electrical parameters of overhead lines (D of OLP) and the distribution of the conductor temperature by length of overhead lines on power losses was assessed by dividing the overhead lines up to 300 km long into shorter sections (columns 4,5 of Table 3).

The impact of the division of the overhead line supplying one load was studied with and without regard to solar radiation .

The losses were calculated for the overhead line divided into 2, 4, 8, 16 identical sections, each of which was modeled by the U-shaped equivalent circuit. The obtained total losses were compared with the losses calculated without division.

As follows from the table 3, the line division into sections decreases the total power losses. For 16 sections, the reduction was 6.78% with regard to solar radiation, and 3.71% without regard to solar radiation ($Qr = 0,\ Qr \neq 0$).

The analysis of the presented findings shows that consideration of the actual temperature of overhead conductors makes it possible to significantly improve the calculation results of network steady states.

The analysis of the proposed improved algorithms has showed their performance. Users of the algorithms should only add data on the environment parameters and the overhead conductor parameters that are included in the heat balance and conductor state equations.

IV. Conclusion

The conducted studies made it possible to solve an important scientific and technical problem of increasing the accuracy of modeling steady states of an electrical network and modeling an overhead line, which is one of its main elements. The problem was solved by the improved algorithms for calculating steady states, which involved the determination of electrical and mechanical parameters of overhead line conductors, such as conductor temperature, resistance, and sag in the span. The electrical and mechanical parameters were determined by the improved algorithms for solving the heat balance and conductor state equations.

The performance of the proposed approaches was verified by their testing via the experimental programs and the SDO-7 program. The numerical results of testing confirm the efficiency of the developed algorithms.

References

[1] Makarov, E.F. Reference book for 0.4-36 kV electrical networks: in 6 vol. / Ed. by I.T. Goryunov et al., M .: *Papyrus Pro*, Vol.1., 608p., 1999, (in Russian.)

[2] Vorotnitsky, V.E., Turkina, O.V. Estimation of errors in the calculation of variable power losses in overhead lines due to the neglect of meteorological conditions, *Elektricheskie stantsii (Power plants)*. No. 10., pp. 42-49., 2008, (in Russian.)

[3] Nikiforov, E.P., Consideration of heating power of overhead line conductors by solar radiation, *Elektricheskie stantsii (Power plants)*. 2008. No. 2. pp. 49-51., (in Russian.)

[4] Nikiforov, E.P., Maximum permissible current loads on the existing overhead line conductors subject to the conductor heating by solar radiation, *Elektricheskie stantsii (Power plants)*. -2006. no. 7. pp. 56-59., (in Russian.)

[5] Karaev, R.I., Volobrinsky, S.D. Electrical networks and power systems. Textbook for universities. 2nd revised edition. M .: "*Transport*", 1988. p.312., (in Russian.)

[6] Zhelezko, Y.S., Methods for calculating standards for process power losses in electrical networks, *Elektrichestvo (Electricity)*. -2006. – No. 12. pp. 10-17., (in Russian.)

[7] Gerasimenko, A.A., Shulgin, I.V. Improvement of technical power losses in overhead lines of distribution networks, Power system: management, competition, education. Collected papers of the III International Scientific and Practical Conf. In 2 vol. Yekaterinburg: USTU-UPI, 2008. – Vol. 2. - p. 191-196., (in Russian.)

[8] Levchenko, I.I., Satsuk, E.I. Load capacity and monitoring of overhead transmission lines in extreme weather conditions, *Elektrichestvo (Electricity)*. No. 4. pp. 2-8., 2008, (in Russian.)

[9] A technique for calculation of limit current loads in terms of conductor heating for existing transmission lines: Soyuztekhenergo, .p. 36., 1987, (in Russian.)

[10] Burgsdorf, V.V., Nikitina, L.G. Determination of feasible load currents of overhead transmission lines by heating their conductors, *Elektrichestvo (Electricity)*. -1989. No. 11. p. 1-8., (in Russian.)

[11] Computational models of load flow in power systems B.I. Ayuev, V.V. Davydov, P.M. Erokhin, V.G. Neuymin. Ed. by P.I. Bartholomei. Moscow, *Flinta: Nauka*, 256p., 2008, (in Russian.)

[12] Timashova, L.V., Merzlyakov, A.S., Nazarov, I.A.

Feasible current loads for overhead line conductors, Energiya yedinoi seti (Energy of the unified network).-2013.-No. 1.pp. 30-39., (in Russian.)

[13] Timofeev, G.S. Comprehensive consideration of configuration and operational-atmospheric factors in the calculation of power losses in distribution networks of power systems: Ph.D. thesis / FSAEI of HE "Siberian Federal University", Krasnoyarsk, 2011.p. 23., (in Russian.)

[14] Figurnov, E.P., Zharkov, Yu.I., Petrova, T.E., Kuusk, A.B. Heating of non-insulated conductors of overhead transmission lines, Elektrichestvo (Electricity).-2013. no. 6. pp.19-25., (in Russian.)

[15] Petrova, T.E., Figurnov, E.P. Overcurrent protection of overhead transmission line conductors, Elektrichestvo (Electricity).-1991.- No. 8.pp.29-34., (in Russian.)

[16] Zhelezko, Yu.S., Nikiforov, E.P., Timashova, L.V. Power losses in electrical networks as a function of weather conditions, Elektricheskie stantsii (Power plants).-2004.- No. 11.pp. 42-48., (in Russian.)

[17] Babnik, T., Makkhovets, B., Perko, M. Distributed monitoring system of power system conditions: application experience, Elektricheskie stantsii (Power plants). -2011. no. 4. pp. 13-17., (in Russian.)

[18] Berdin, A.S., Kovalenko, P.Yu. Determination of the parameters of transmission line equivalent circuit by vector measurements, Power industry through the eyes of young people: Proceedings of the 3rd International Scientific- Technical Conf. Collected papers. In 2 vol. Yekaterinburg: UrFU, 2012. Vol.2. p. 29-32., (in Russian.)

[19] Bartholomei, P.I., Eroshenko, S.A., Lebedev, E.M., Suvorov, A.A. New information technologies for FACTS observability based on PMU measurements, Power industry through the eyes of young people. Collected papers of the 3rd International Scientific-Technical Conf. Yekaterinburg: UrFU, 2012. v.2. - p 17-23., (in Russian.)

[20] Faibisovich, V.A., Lordkipanidze, V.D. Determination of power system parameters; new methods for experimental determination. Moscow, .: Energoatomizdat, 1982. -120p., (in Russian.)

[21] Suvorov, A.A. Adaptive identification of the parameters of electrical network elements for online and emergency control: Ph.D.thesis/ USTU-UPI. Yekaterinburg, 2003. -21p., (in Russian.)

[22] Cheremisin, N.M., Cherkashina, V.V., Kholod, A.V. Improvement of operating condition control of electric power systems within the framework of the SMART GRID concept, Energy sector: control, quality and efficiency of using energy resources: Collected papers of the 7th All-Russian Scientific-Technical Conf. with int. participation.- Blagoveshchensk: AmSU, 2013. p.66-69., (in Russian.)

[23] Popova, E.V. An algorithm for determining the conductor temperature subject to solar radiation// Methodological issues of large energy system reliability study. Problems of study and reliability support of liberalized energy systems. Collected papers of the International Scientific Workshop. -Irkutsk: ISEM SO RAN, 2011. Issue 61. pp. 49-56., (in Russian.)

[24] Voitov, O.N., Semenova, L.V., Popova, E.V. Power flow calculation in an electrical network subject to the heat balance equation of overhead line conductors// Methodological issues of large energy system reliability study. Reliability problems of existing and prospective energy systems and methods for their solution. Collected papers of the International Scientific Workshop. -Ivanovo: PresSto, 2011. Issue.62. pp. 406-414., (in Russian.)

[25] Voitov, O.N., Popova, E.V., Semenova, L.V. Algorithms for power flow calculation in electrical networks// Elektricheskie stantsii (Power plants).-2013.-No. 3. pp. 19-26., (in Russian.)

[26] Popova, E.V. An algorithm for determining the conductor temperature subject to environment parameters, Power industry through the eyes of young people: Proceedings of the 3rd International Scientific-Technical. Conf. Collected papers. In 2 vol. Yekaterinburg: UrFU, 2012. Vol. 1. p.351-356.

[27] Fokin, V.M. Basic principles of energy saving and energy audit. Moscow,.: Mashinostroenie-1(Mechanical Engineering-1), 2006.-256p., (in Russian.)

[28] Bubenchikov, A.A. Calculation of temperature and power losses in self-supporting insulated conductors of overhead transmission lines of electric power systems: Ph.D. thesis / OmSTU. -Omsk, 2012.-20p., (in Russian.)

[29] Zarudsky, G.K., Zinner, L.E., Syromyatnikov, S.Yu. Calculation of the temperature of overhead EHV line conductors based on the criterion experiment design. –Bulletin of MPEI, 1997.-No. 12., (in Russian.)

[30] Satsuk, E.I. Electrothermal and mechanical processes in overhead transmission lines.-Novocherkassk: SRSTU (NPI), 2010., (in Russian.)

[31] Petrova, T.E. Calculation of heating of contact line conductors. – Bulletin of VNIIZHT, 1987. no. 3., (in Russian.)

[32] Nikiforov, E.P. A technique for calculating the maximum permissible temperatures and current loads of existing transmission line conductors, Elektricheskie stantsii (Power plants). -2010. no. 10 p.60-64., (in Russian.)

[33] Shulgin, I.V. Statistical modeling of loads in the problem of determining the integral characteristics of power distribution systems: Ph.D. thesis/ Krasnoyarsk,

2013.-20p., (in Russian.)

[34] Berdin, A.S., Kovalenko, P.Yu. Determination of the equivalent circuit parameters of transmission line by phasor measurements// Power industry through the eyes of young people. Collected papers of the 3rd International Scientific-Technical Conf. Yekaterinburg: UrFU, 2012. V.2. – p. 29-32 (in Russian.)

[35] Isachenko, V.P. et al. Heat transfer: Textbook for universities / V.P. Isachenko, V.A. Osipova, A.S. Sukomel. -4th revised edition - M.: Energoizdat, 1981.-416p., (in Russian.)

[36] Heat and mass transfer. Thermotechnical experiment: Reference book / E.V. Ametistov, V.A. Grigoriev, B.T. Yemtsev et al .; Ed. by V.A. Grigoriev and V.M. Zorin. Moscow, .: Energoizdat, 1982.-512p., (in Russian.)

[37] Levchenko, I.I., Satsuk, E.I. Software of the information system for icing control/ / Elektricheskie stantsii (Power plants).-2004. no. 10. p.15-19., (in Russian.)

[38] Popova, E.V. Calculations of power flow in power systems in terms of the dimensions of overhead lines, Energy of Russia in the XXI century. Innovative development and management: Collected papers of the All-Russian Conference. -Irkutsk: ISEM SO RAN, 2015. pp. 372-378., (in Russian.)

[39] Kurbatsky, V.G. Mathematical problems of electric power industry: Manual. In 2 parts. – Part 1. Foundations of the application of elements of linear algebra and graph theory in electric power industry / V.G. Kurbatsky, N.V. Tomin.-Bratsk: SEI of HE "BrSU", 2007.-142p., (in Russian.)

[40] Murashko, N.A., Okhorzin, Yu.A., Krumm, L.A. et al. Analysis and control of power system steady states.- Novosibirsk: Nauka, 1987.-240 p., (in Russian.)

[41] Software tool (ST SDO-7) for steady state analysis and optimization, and assessment of power losses in electrical networks, version 1. - State Standard of Russia, Certificate of Conformity No. ROSS RU.SP20.0001.11SP20., (in Russian.)

[42] Voitov, O.N., Semenova, L.V., Chelpanov, A.V. Algorithms for assessing power losses in an electrical network and their software support// Elektrichestvo (Electricity).-2005.-No. 10. pp. 45-54., (in Russian.)

[43] Del-Pino-Lopez, J.C., Garrido-Garcia, D., Cruz-Romero, P., Gomez-Exposito, A. Novel conductor design to increase the thermal rating of overhead lines, RE&PQJ.- May 2016.-Vol. 1.- No. 14. pp. 973-978.

[44] The thermal behavior of overhead conductor. – Elektra, 1992.-No. 144.

[45] Zima, M., Larsson, M., Korba, P. et al. Design Aspects for Wide-Area Monitoring and Control Systems. – Proc. of the IEEE, 2005.-Vol.93.-No. 5.

[46] Di Shi, Tylavsky, Daniel J., Koellner, Kristian M., Naim Logik and Wheeler, David E. Transmission line parameter identification using PMU measurements, Euro. Trans. Electr. Power.-2011.-No. 21. pp. 1574-1588.

[47] Xiaomeing Bian, Rong Li, X., Huimin Chen, Deqiang Gan and Juju Qiu. Joint Estimation of State and Parameter with Sinchrophasors – Part I. State Tracking, *IEEE Transactions on Power Systems*, 2011.Vol. 26.-No. 3. pp. 1196-1208.

[48] Zamora-Cardenas, A., Claudio, R. Fuerte-Esquivel. State estimation of power system containing FACTS controllers, Electric *Power System Research*.- Apr. Vol. 81. Issue 4. pp. 995-1002, 2011.

[49] IEC 1597. Overhead electrical conductors. – Calculation methods for stranded bare conductors. p. 15.

[50] Thermal state of overhead line conductors, *Electra*, 1988. no. 121, pp. 51-67.

[51] Crocch, P.E., Tyalovsky, D.J., Chen, H., Jarriel, L. Critically coupled algorithms for solving the power flower equation, *IEEE Transactions on Power Systems,* Vol. 7., no. 1. pp. 451-457.

[52] Hubbi, W. The mismatch theorem and second order load flow algorithms, *IEEE Proc*., Vol. 134. pp. 189-194, 1985.

[53] Hubbi, W., Rofsum, A. Starting algorithms and modification for Newton-Raphson load flow method, *Elec. Power and Energ. Syst.*, Vol. 5, no. 3.-pp. 166-172, 1983.

[54] Luo, G. X., Semlyen, A. Efficient load flow for large weakly meshed networks, *IEEE Transactions on Power Systems*, Vol. 5.- No. 4. pp. 1309-1316, 1990.

[55] Monticelli, A., Garcia, A., Saverdra, O. R. Fast decoupled load flow: hypothesis, derivations and testing, *IEEE Transactions on Power Systems*, Vol.5, no. 4.pp.1425-1431.

[56] Popova, E.V. Improvement of algorithms for calculating the power flow in electric power systems subject to the current temperature conditions of overhead transmission lines: Ph.D. thesis ISEM SO RAN. Irkutsk, 2017, (in Russian.)

[57] Bronstein, I.N., Semendyayev, K.A. Handbook of mathematics for engineers and students of high schools. .- "Nauka", Ch. ed. board Phys.Moscow,at. Lit., 1980.-720 p., (in Russian.)

[58] Voitov, O.N., Semenova, L.V., Popova, E.V. Algorithms to calculate the steady state of an electrical network subject to constrants on the temperature and sag of an overhead line conductor, Methodological issues of studying reliability of large energy systems. Reliability of developing energy systems. In 2 books

Collected papers of the international Scientific Workshop. – Irkutsk: ISEM SO RAN, Issue 69. pp. 39-48, 2018.

[59] IEEE Std 738-2012: IEEE Standard for Calculation the Current-Temperature Relationship of Bare Overhead Conductors; I*EEE Standard Association*: Washington, U.S.A.; 23; December; 2013.

[60] International Council on Large Electric Systems, CIGRE. Guide for Thermal Rating Calculation of Overhead Lines; Technical Brochure 601; *CIGRE*: Paris, France; December; 2014.

[61] Rui Yao, Kai Sun, Feng Liu, and Shengwei Mei. Efficient Simulation of Temperature Evolution of Overhead Transmission Lines Based on Analytical Solution and NWP, *IEEE Transactions on Power Delivery*, DOI 10.1109/TPWRD.2017.2751563.

[62] Shakirov, R.G, Fedorov, N.A. Calculation of hear transfer from the surface of uninsulated cables of a new generation, Elektricheskie stantsii (Power plants,) no. 1. pp. 28-33, 2019.

[63] Gerasimenko, A.A. Statistical methodology of modeling the variety of operation conditions in the problem of reactive load compensation in distribution power systems: Dr. Sc. thesis, FSBEI HPE “Siberian Federal University,” Krasnoyarsk, p. 25, 2019.

[64] Bigun, A.Ya. Calculation of temperature and energy losses in overhead conductors under unsteady thermal conditions of operation: Ph.D. thesis, OmSTU. Omsk, p. 23, 2018.

[65] Konstantinos K., Simon M. Rowland, and Boud Boumecid. A Holistic Method for Conductor Ampacity and Sag Computation on an OHL Structure, *IEEE Transactions on Power Delivery*, vol. 27, no 3, pp.1047-1054, 2012, DOI: 10.1109/TPWRD.2012.2187464.

[66] Yong Li, Juanxia Xiao, Chun Chen, Yi Tan, Yijia Cao. Service Restoration Model with Mixed-Integer Second-Order Cone Programming for Distribution Network with Distributed Generations, *IEEE Transactions on Smart Grid*, vol. PP, № 99, June 2018, DOI:10.1109/TSG.2018.2850358.

[67] Yong Li, Li He, Fang Liu, Canbing Li, Yijia Cao, Mohammad Shahidehpour. Flexible Voltage Control Strategy Considering Distributed Energy Storages for DC Distribution Network, *IEEE Transactions on Smart Grid*, vol. 10, Issue 1, pp.163-172, Jan 2019, DOI 10.1109/TPWRD.2012.2187464.

Oleg Voitov graduated from the Faculty of Power Engineering of Moscow Power Engineering Institute in 1971. In 1992, he received his Ph.D. degree from Melentiev Energy Systems Institute. Currently he is a Senior Researcher at Melentiev Energy Systems Institute of SB RAS. His research interests include analysis and control of operating conditions of electric power systems.

Ekaterina Popova graduated from the Energy Faculty of Irkutsk Polytechnic Institute in 1989. In 2017, she received her Ph.D. degree from Melentiev Energy Systems Institute. Currently she is a Senior Engineer at Melentiev Energy Systems Institute of SB RAS. Her research interests include analysis and control of steady states of electric power systems and parameters of overhead transmission lines.

Ludmila Semenova graduated from the Energy Faculty of Irkutsk Polytechnic Institute in 1974. Currently she is a Leading Engineer at Melentiev Energy Systems Institute of SB RAS. Her research interests include analysis and control of operating conditions of electric power systems.

Locational Marginal Pricing in Multi-Period Power Markets

Tatiana A. Vaskovskaya*

National Research University "Moscow Power Engineering Institute", Moscow, Russia.

***Abstract* — The objective of this paper is to develop an analytical framework for interpretation of locational marginal prices (LMPs) in multi-period power markets with intertemporal ramping, limited energy, and energy storage constraints. Previous research dedicated to the techniques for decomposition of LMPs explicitly shows their formation as a spatial structure of components due to power flow, transmission and voltage constraints. In contrast to the traditional point of view, this study proposes formulae for discussing a temporal LMP structure, where LMPs are obtained as Lagrange multipliers for nodal real power balances in a multi-period AC optimal power flow (OPF) problem. In the beginning, marginal resources are discussed. It is shown that an energy resource with unbounded output at a specific time period may not be marginal. Then, the resources that actually form LMPs in the energy system are determined. The study shows that not all marginal resources directly affect LMPs. Finally, the dependence of LMPs on marginal resources from different time periods is considered. It is shown that binding ramping constraints lead to "cardiogram" curves of LMPs, while limited energy and energy storage constraints smooth them out and are used to form LMPs based on the overall price situation in specific time periods. The aim of the methodology is not to determine LMPs but to identify contribution of particular constraints that affect their formation. The methodology has been tested on the IEEE-30 energy system extended with a daily load profile for a day-ahead market with a full AC OPF model.**

***Index Terms* — Locational marginal prices, multi-period power market, ramping rates, energy storage.**

* Corresponding author.
E-mail: tatiana.vaskovskaya@gmail.com

http://dx.doi.org/10.25729/esr.2019.02.0003
Received June 21, 2019. Revised July 07.
Accepted Sept. 03, 2019. Available online Novenber 15, 2019.

NOMENCLATURE

Sets and indices:

$g \in \mathcal{G}$	Generators
$d \in \mathcal{D}$	Demands
$i \in \mathcal{N}$	Nodes
$s \in \mathcal{S}$	Storage resources including generating $g = s$ and demanding $d = s$ resources
$r \in \mathcal{R}$	Different resources like generators, demands, or storage
$t \in \mathcal{T}$	Time periods
t_{start}	Initial time period ($t_{start} \notin \mathcal{T}$)
t_{end}	Last time period $t_{end} \in \mathcal{T}$

Parameters:

$\overline{E}_g, \underline{E}_g$	Maximum and minimum energy limits for generator g (MWh)
$C_{g,t}, C_{d,t}$	Offer cost of generator or storage g and bid cost of demand or storage d at time period t (rub/MWh)
R_g^+, R_g^-	Maximum ramp-up and ramp-down rates for generator g
$\overline{P}_d, \underline{P}_d$	Maximum and minimum real power output levels for demand or storage d (MW)
$\overline{P}_g, \underline{P}_g$	Maximum and minimum real power output levels for generator or storage g (MW)
$\overline{SC}_s, \underline{SC}_s$	Maximum and minimum state of charge levels for storage s (MWh)
$Q_{d,t}$	Reactive power demand d at time period t (MVAr)
$\overline{Q}_g, \underline{Q}_g$	Maximum and minimum reactive power output levels for generator or storage g (MVAr)
$\eta_s \le 1$	Storage s storing efficiency
$\eta_d \le 1$	Storage d charging efficiency
$\eta_g \ge 1$	Storage g discharging efficiency
Δt	Time period duration (hr)

Optimization variables:

$SC_{s,t}$	State of charge for storage s at time t (MWh).

$P_{g,t}, P_{d,t}$ Real power output levels for generator or storage g and demand or storage d at time period t (MW).

$Q_{g,t}$ Reactive power output levels for generator or storage g at time t (MW)

X_t Vector of voltage phases and magnitudes at time t (deg, p.u.)

Dual variables:

λ_t^{node} Vector of Lagrange multipliers associated with nodal power balance constraints for real (which define LMP) and reactive power at time period t.

$\lambda_t^{tc}, \lambda_t^{vc}$ Vector of Lagrange multipliers associated with transmission and voltage constraints at time period t

$\nu_{g,t}^{+}, \nu_{g,t}^{-}$ Lagrange multipliers associated with intertemporal ramping constraints for generator g at time period t

$\overline{\nu}_g^E, \underline{\nu}_g^E$ Lagrange multipliers associated with intertemporal limited energy constraints for generator g

$\nu_{s,t}$ Lagrange multipliers associated with storage s' state of charge at time period t

$\overline{\pi}_{g(d),t}, \underline{\pi}_{g(d),t}$ Lagrange multipliers associated with maximum and minimum active power output levels

$\overline{\pi}_{s,t}^{SC}, \underline{\pi}_{s,t}^{SC}$ Lagrange multipliers associated with state of charge constraints for storage s at time period t

Other variables:

B_j Cost component of resource j (storage s or other resources) in the social benefit function.

$J_t^{node}, J_t^{tc}, J_t^{vc}$ Jacobian matrices in respect to voltage phases and magnitudes X for nodal power balance, transmission, and voltage constraints at time period t

$\Delta\lambda_t^f, \Delta\lambda_t^{tc}, \Delta\lambda_t^{vc}$ LMP components at time period t due to power flow, transmission and voltage constraints.

I. Introduction

Decentralized electricity sectors in many parts of the world allowed raising competition among owners of power generating equipment. Nodal pricing of electricity through locational marginal prices (LMPs) gives incentives to safely manage an energy system characterized by congestion and dependence on detached behavior of different stakeholders [1, 2]. Being one of the most powerful tools of congestion management, LMPs are implemented in many electricity markets all over the world, including Russia, the United States, New Zealand, Singapore, etc.

The LMP at a particular node is defined as a response of the system in the form of an increased cost called marginal cost to an incremental increase in a demand at that particular node while respecting all the security constraints of the system. Disparate locations of nodes lead to different marginal costs due to distinctive losses, diverse influence of transmission and other constraints.

There has been a very significant research effort undertaken internationally since the 1990s to understand how LMPs are derived, how to interpret and decompose them as understandable components. A classical approach allows decomposing each LMP into energy, loss and congestion components [3, 4, 5]. This approach is still viable in present days but needs to reflect the greater perception of the role of marginal generators [6, 7].

Generation scheduling meets different multi-period constraints, the most known of which are limited energy, energy storage and ramping constraints.

Traditional energy storage systems imply hydropower reservoir systems [8, 9], which could include either common or pumped-storage hydro plants. Water reservoir constraints are controlled during daily hydrothermal generation scheduling [10, 11]. Similar to limited energy hydro power plants, some thermal power plants need to be rescheduled while meeting fuel constraints [12].

Pumped hydro energy storage provides various services and contributions to the power system including load leveling, maintenance of voltage and stability in a system, generating capacity, etc. Using pumped hydro energy storage allows reduction in overall energy system costs and CO2 emissions. Currently, the co-use of pumped hydro energy storage in power markets usually causes trouble because of the necessity of predicting charging and discharging windows, and can be improved [13].

For pumped-storage hydropower plants, as well as other storage systems, the Federal Energy Regulatory Commission in the USA tries to remove legislature barriers to the participation of electric storage resources in the capacity, energy, and ancillary service markets operated in the USA [14, 15]. A great interest is dedicated to the level of models and algorithms of OPF with energy storage [16, 17]. Apart from direct market implementation, there are propositions of financial storage rights [18, 19] and, what is more, the idea of electric vehicles as electricity storage devices may be relevant [20, 21].

According to [22, 23, 24], energy storage technologies are still too expensive for full deployment to benefit power markets, although, technological advance in different types of storage makes it rational to pre-define a full-fledged participation as an independent resource in economic dispatch and market operations.

High penetration of renewable resources with its inherent variability dictates new unconventional methods of energy management. The famous transformation of daily load shape into a "duck curve" in California power market requires advanced ramping capacity to handle sharp conventional power generation changes [25, 26]. The need for an exact model of ramping constraints arose. In order to provide correct price signals, authors of [16, 27] propose new pricing models for real-time markets, while in [28, 29] ramping products, namely, additional payments for generators selected to provide ramping capability are discussed.

In the Russian power market [30], there are ramping constraints and limited energy constraints. The former occur mainly in the European region, the latter are relevant for hydro plants in Siberia and Volga regions. While energy storage constraints are not incorporated into market procedures, there are bulk energy storage resources like the Zagorskaya pumped-storage hydro plant with a 1200 MW generation capacity, 1320 MW charging capacity, and a yearly generation of 1 900 million kWh [31]. The goal of the paper is relevant for the Russian power market since the existing intertemporal constraints affect LMPs in day-ahead and balancing markets and the prospect of implementing energy storage constraints may benefit as in the case of reducing overall energy system costs.

LMPs as Lagrange multipliers in a multi-period OPF incorporate intertemporal constraints along with transmission and voltage constraints. This brings on new issues in the field of LMP interpretation. The first issue lies in the ambiguity of a status of a marginal generator or, more generally, a marginal resource. In [16], a resource is called marginal when its output is not bounded with the corresponding instantaneous maximum and minimum output level constraints. In [32], on the contrary, all corresponding constraints should be non-binding to call a resource marginal. In order to study LMPs and their interpretation we need to examine the marginal status of a resource by means of the Karush-Kuhn-Tucker (KKT) necessary conditions and possibility of responding to the market needs. The second issue arises with interconnection of time periods when a marginal resource in one period affects the LMPs in other periods. In conclusion, we can infer that the temporal formation of LMP, in contrast to its one-period spatial structure, is studied insufficiently.

This paper attempts to measure LMPs under intertemporal constraints and bridge the gap in the LMP interpretation in the multi-period OPF. The objectives of this study are (a) to analyze the economic impacts of current multi-period ramping and energy constraints; (b) to introduce a new product of energy storage in the optimization problem; and (c) to explore the conditions affecting the LMP by different intertemporal constraints. While meeting the objectives, we consider a day-ahead market and a simulated market clearing process of a scaled system in the full AC OPF framework.

This approach differs from the previous studies in that a) a full AC OPF framework is used, b) the focus is made on LMPs and their formation, c) a new presentation of a marginal resource is contributed, and d) a class of different intertemporal constraints is considered and a methodology for its analysis is proposed. These can be implemented into daily economic dispatch carried out by system and trade operators using intertemporal constraints to optimally allocate available resources and understand locational marginal pricing behind it.

The paper is organized as follows. Section II gives a brief overview of the mathematical background behind LMPs in a system. The proposed methodology of separating out marginal and price-forming resources in the multi-period market is shown in detail in Section III. Section IV is dedicated to LMP formation under intertemporal constraints. The methodology is applied using the IEEE-30 test system, the results of which are shown in Section V. Finally, Section VI draws the conclusions of the paper.

II. Theoretical framework

The general statement of the multi-period market optimal power flow model can be considered as the following programming problem:

$$f = \sum_{t\in\mathcal{T}}\left(\sum_{d\in\mathcal{D}} C_{d,t}P_{d,t} - \sum_{g\in\mathcal{G}} C_{g,t}P_{g,t}\right) \to max, \quad (1)$$

$$g\left(P_{g,t}, P_{d,t}, Q_{d,t}, Q_{d,t}, X_t\right) \le 0, t \in \mathcal{T}, (\lambda) \quad (2)$$

$$h\left(P_{g,t}, P_{d,t}, SC_{s,t}\right) \le 0, t \in \mathcal{T}, (\nu) \quad (3)$$

$$v\left(P_{g,t}, P_{d,t}, Q_{g,t}, SC_{s,t}\right) \le 0, t \in \mathcal{T}, (\pi) \quad (4)$$

The objective of the problem statement (1) is to maximize social benefit across the considered time interval, for example the entire day in a day-ahead market. Constraint (2) represents real and reactive nodal power balances in AC form, transmission and voltage constraints dependent on magnitudes and angles of voltage variables X_t for each time period t. Constraint (3) represents the intertemporal constraints: ramping constraints, energy storage constraints, and energy limited constraints due to fuel limitations, CO_2 emission constraints, and water storage constraints. Constraint (4) represents maximum and minimum levels of the problem's variables.

The Lagrangian function of the stated problem (1)–(4) is the following:

$$L = -f + g^T\lambda + h^T\nu + v^T\pi. \quad (5)$$

To study LMP formation, we need to consider the KKT necessary first-order conditions for derivatives with respect to X, $P_{(g,t)}$, and $P_{(d,t)}$. After they are obtained, we have

$$\frac{\partial L}{\partial P_{g,t}} = C_{g,t} - LMP_{i,t} + J_{h\,i,t}^T\nu + \overline{\pi}_{g,t} - \underline{\pi}_{g,t} = 0, \quad (6)$$

$$\frac{\partial L}{\partial P_{d,t}} = -C_{d,t} + LMP_{i,t} + J_{h\,i,t}^T\nu + \overline{\pi}_{d,t} - \underline{\pi}_{d,t} = 0, \quad (7)$$

$$\frac{\partial L}{\partial X} = J_g^T\lambda = 0, \quad (8)$$

where J_g, J_h are Jacobian matrices of constraints (2) and (3) respectively. Jacobian matrix J_g is a block-diagonal matrix consisting of J_t^{node}, $J_t^{tc}, J_t^{vc}, t \in \mathcal{T}$. Vector λ consists of vectors λ_t^{node}, $\lambda_t^{tc}, \lambda_t^{vc}, t \in \mathcal{T}$.

The formulae (6)–(7) bind LMPs with marginal costs of available resources. That is why they allow defining how LMPs at marginal nodes in the system are formed. It can be seen that formula (8) defines formation of LMPs at different nodes at different time periods as far as it contains LMPs at all nodes and provides interdependence between them and other Lagrange multipliers.

Generators (ergo demands) are traditionally called marginal if their resource's outputs are not bounded and $\overline{\pi}_{g,t(d,t)} = \underline{\pi}_{g,t(d,t)} = 0$. Integration of resources in different time periods connected by intertemporal constraints makes things confusing. Formulae (6)–(7) for the mentioned unbound resources are written as follows:

$$LMP_{i,t} = C_{g,t(d,t)} \pm J_{h\ i,t}^{T} \nu, \qquad (9)$$

where $C_{g,t(d,t)}$ is the marginal cost of the corresponding resource, $J_{h\ i,t}^{T} \nu$ is the marginal opportunity cost, that is the cost of choosing other resources for production.

The next sections discuss marginal resources with regard to the intertemporal constraints and LMP formation under their influence. Specific models of intertemporal constraints such as ramping constraints, energy limited constraints, and energy storage constraints are considered.

III. Marginal resources in multi-period market

Marginal pricing is the ground for optimal allocation of generating resources to produce electricity with maximum social benefit. The well-known analysis of locational marginal pricing discloses different marginal generators in the system due to economic similarity based on penalty factors and economic diversity caused by transmission and voltage constraints.

A. Ramping Constraints

We formulate ramping constraints as a limited change in power output by ramp-up and ramp-down rates:

$$-R_g^- \le P_{g,t} - P_{g,t-1} \le R_g^+. \qquad (10)$$

Suppose a generator meets ramp-up rate constraints during one time range consisting of $m + 1$ time periods. After that, during another period time range consisting of $n + 1$ periods, it meets ramp-down rate constraints. In this case, relations (6) written for those ranges are the following:

$$\begin{gathered}
LMP_{i,t_1} = C_{g,t_1} - \nu^+_{g,t_1+1} - \underline{\pi}_{g,t_1} \\
LMP_{i,t_1+1} = C_{g,t_1+1} - \nu^+_{g,t_1+2} + \nu^+_{g,t_1+1} \\
\dots \\
LMP_{i,t_1+m-1} = C_{g,t_1+m-1} - \nu^+_{g,t_1+m} + \nu^+_{g,t_1+m-1} \\
LMP_{i,t_1+m} = C_{g,t_1+m} + \nu^+_{g,t_1+m} + \overline{\pi}_{g,t_{1+m}} \\
\dots \\
LMP_{i,t_2} = C_{g,t_2} + \nu^-_{g,t_2+1} + \overline{\pi}_{g,t_2} \\
LMP_{i,t_2+1} = C_{g,t_2+1} + \nu^-_{g,t_2+2} - \nu^-_{g,t_2+1} \\
\dots \\
LMP_{i,t_2+n-1} = C_{g,t_2+n-1} + \nu^-_{g,t_2+n} - \nu^-_{g,t_2+n-1} \\
LMP_{i,t_2+n} = C_{g,t_2+n} - \nu^-_{g,t_2+n} - \underline{\pi}_{g,t_2+n}
\end{gathered} \qquad (11)$$

By considering the sum of LMPs at node i of generator g for these periods, we have

$$\begin{gathered}
\sum_{t\in\mathcal{T}_1} LMP_{i,t} = \sum_{t\in\mathcal{T}_1} C_{g,t} - \underline{\pi}_{g,t_1} + \overline{\pi}_{g,t_{1+m}} \\
\sum_{t\in\mathcal{T}_2} LMP_{i,t} = \sum_{t\in\mathcal{T}_2} C_{g,t} + \overline{\pi}_{g,t_2} - \underline{\pi}_{g,t_2+n}
\end{gathered} \qquad (12)$$

A marginal generator in its traditional sense defines system price of electricity, which is equal to the generator marginal cost.

If at time periods t_1, t_1+m, t_2, t_2+n the generator does not hit its limits and $\underline{\pi}_{g,t_1} = \overline{\pi}_{g,t_{1+m}} = 0, \overline{\pi}_{g,t_2} = \underline{\pi}_{g,t_2+n} = 0,$ we have the equality for mean prices:

$$A\left(LMP_{i,t\in\mathcal{T}_1}\right) = A\left(C_{g,t\in\mathcal{T}_1}\right), A\left(LMP_{i,t\in\mathcal{T}_2}\right) = A\left(C_{g,t\in\mathcal{T}_2}\right) \qquad (13)$$

The example of a schedule for this situation is shown in Fig. 1, (a). Such a generator will be considered to be marginal in several time periods because its average LMP corresponds with average marginal cost and its output can be changed under variation in system load.

More frequently ramping constraints are met starting with one of the limits - $\underline{P}_g$ or $\overline{P}_g$. There are no grounds to call such a generator marginal. This resource will not change its output that is bounded by minimum, maximum, and ramping level bounds. Consequently, the generator is considered to be bounded and non-marginal. The example of a non-marginal generator under ramping constraints is shown in Fig. 1, (b). One can see that for the non-marginal generator, it is also necessary to consider several time periods.

Nevertheless, we note that as the generator's output increases, its state changes from minimum to maximum possible level moving from $\underline{P}_g$ or $\overline{P}_g$. At the same time, LMPs in the system increaserise from $LMP_{i,t_1} \le C_{g,t_1}$ to $C_{g,t_1+2} \le LMP_{i,t_1+2}$, i.e. the LMP rises beyond the generator's marginal cost.

B. Energy Limited Constraints.

Consider the following constraints written through the sum of active power outputs for energy constraints:

$$\underline{E}_g \le \sum_{t\in\mathcal{T}} P_{g,t}\Delta t \le \overline{E}_g. \qquad (14)$$

They mean the restriction on summary energy output for generator g. Under these constraints, a new form of (9) is as follows:

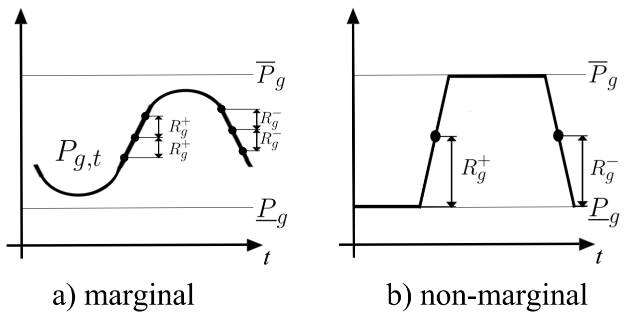


Fig. 1. Generator state under ramping constraints.

$$LMP_{i,t} = C_{g,t} + \overline{\nu}_g^E \Delta t - \underline{\nu}_g^E \Delta t, \tag{15}$$

where $C_{(g,t)} = C_g = idem$.

The marginal opportunity cost for a generator with energy constraints consists of $\overline{\nu}_g^E \Delta t - \underline{\nu}_g^E \Delta t$ and is constant for all considered time periods.

By working with energy constraints of hydro power plants, we can assume that their marginal cost C_g is relatively low in comparison with the prices in the energy system. Regardless of unbounded output at every period, the resource is not marginal. Addressing the bounded maximum energy level constraint for a longer period, we can interpret one whole day as one period. At this integral period, the considered resource is infra-marginal. There is no reason to consider it as marginal during this day.

Another example of energy constraints is a fuel or CO_2 emission-limited power plant with, for example, a relatively high marginal cost. Then, the previous speculations are symmetrical. This resource is extra- marginal (not marginal as well).

The only possible reason to consider such a resource to be marginal is to have non-binding energy constraints with $\underline{\nu}_g^E = \overline{\nu}_g^E = 0$. Then, some time periods will be characterized by power generation at minimum or maximum possible levels. For some time periods, it is necessary for the generator to be unbounded with $LMP_{i,t} = C_{g,t}$. Fig. 2 shows the examples of marginal, infra-marginal and extra-marginal limited energy generator output, respectively.

Thus, through all time periods, e.g. a day, the considered power plant may be infra-marginal, marginal, or extra-marginal, regardless of a single period situation.

C. Energy Storage Constraints

A storage constraint can be introduced by the following expressions:

$$\underline{SC}_s \le SC_{s,t} \le \overline{SC}_s, \tag{16}$$

$$SC_{s,t} = \eta_s SC_{s,t-1} + \eta_d P_{d=s,t}\Delta t - \eta_g P_{g=s,t}\Delta t. \tag{17}$$

Inequalities (16) impose a one-period constraint on minimum and maximum state of charge at time period t while (17) expresses how the state of charge changes in length of time.

Similar to other resources, an energy storage is represented in the target function by the benefit component that is maximized in sum with other components:

$$B_s = \sum_{t\in\mathcal{T}, d=s, g=s} \left(C_{d,t}P_{d,t} - C_{g,t}P_{g,t}\right). \tag{18}$$

It is supposed that $C_{(d,t)} = C_d = idem$, $C_{(g,t)} = C_g = idem$.

This component reveals the arbitrage between periods of low and high LMPs to utilize the storage resource according to its desired marginal cost. As long as a storage benefit component is higher than the social benefit of other resources, it is a signal to charge the storage resource in the low marginal cost periods and to discharge it in the high marginal cost periods.

Under storage constraints, (9) is written as follows:

$$LMP_{i,t} = C_{g(d)} + \eta_{g(d)}\nu_{s,t}\Delta t, \tag{19}$$

where $\nu_{(s,t)}$ are Lagrange multipliers for storage state equality constraints (17). For the analysis of $\nu_{(s,t)}$, we need to consider $\partial L/\partial SC_g$, which is

$$\frac{\partial L}{\partial SC_g} = \nu_{s,t} - \nu_{s,t+1}\eta_s + \overline{\pi}_{s,t}^{SC} - \underline{\pi}_{s,t}^{SC}. \tag{20}$$

With reference to (20), after equating it to zero, we can see that $\nu_{s,t} = \nu_{s,t+1}\,\eta_s$ during charging and discharging of the storage resource. In other time periods, when charge increases to $\overline{SC}_s$ or decreases to $\underline{SC}_s$, the Lagrange multiplier $\nu_{s,t}$ changes its value. Thus, the storage constraints are similar to energy ones during charging and discharging phases only.

The storage resource is marginal if the storage state of charge does not hit $\overline{SC}_s$, $\underline{SC}_s$ during charging phase, i.e., the full storage capacity is not used by the market (Fig. 3).

Taking (17) into consideration, we know that

$$\begin{aligned} B_s = &\left(C_d - \frac{\eta_g}{\eta_d}C_g\right)\sum_{t\in\mathcal{T}} P_{d,t} + \\ &\frac{\eta_g}{\eta_d}\frac{C_g}{\Delta t}(1-\eta_s)\sum_{t\in\mathcal{T}\setminus t_{end}} SC_{s,t} + \\ &\frac{\eta_g}{\eta_d}\frac{C_g}{\Delta t}\left(SC_{s,t_{end}} - \eta_s SC_{s,t_{start}}\right). \end{aligned} \tag{21}$$

Considering that the effective energy storage with η_s=1 and without negative LMPs at the current and previous time periods resulted in $SC_{s,t_{end}} = SC_{s,t_{start}} = 0$, we have

$$B_s = \left(C_d - \frac{\eta_g}{\eta_d}C_g\right)\sum_{t\in\mathcal{T}} P_{d,t}. \tag{22}$$

Marginal cost of the storage resource under considered conditions would be $C_d - \frac{\eta_g}{\eta_d}C_g$. It characterizes the LMP

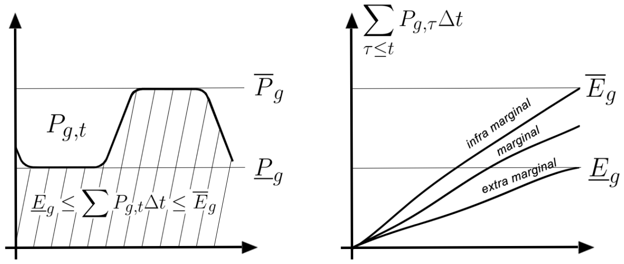


Fig. 2. Generator state under limited energy constraints.

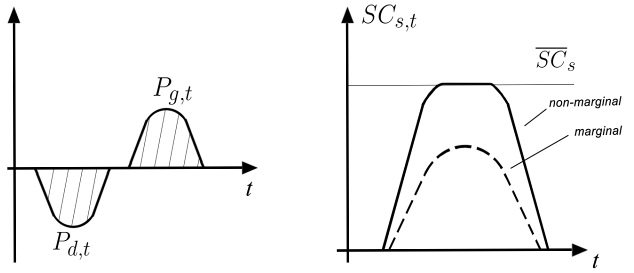


Fig. 3. Storage state.

difference at the storage resource node during charging and discharging time periods, while LMPs at those time periods remain the same. Unlike other types of resources, for which marginal costs are represented in LMPs, the difference of LMPs in the storage resources varies:

$$\Delta LMP_{i,t} = C_g - C_d + \left(\eta_g \nu_{s,t_g} - \eta_d \nu_{s,t_d}\right)\Delta t, \quad (23)$$

where, apart from the efficiency factor η_g, η_d, Lagrange multiplier ν_{s,t_d} increases to ν_{s,t_g}, if Lagrange multipliers $\overline{\pi}_{s,t}^{SC}, \underline{\pi}_{s,t}^{SC}$ corresponding to maximum and minimum levels of state of charge are nonzero. It means that $\Delta LMP_{i,t}$ is greater or equal to price difference $C_g - C_d$ for both marginal and non-marginal storage resources.

Nevertheless, the mutually optimized demand and generation sides of storage just conform to current price situation and do not set prices independently. The marginal storage resource allows reloading conventional resources in order to obtain the desired difference of LMPs. It affects the range but not the size of LMPs.

D. Marginal and Price-forming Resources

As was shown above, the introduction of intertemporal constraints in the multi-period market requires a more formal definition of a marginal resource. Moreover, it is necessary to determine how different types of marginal resources affect prices.

We propose a definition of marginal resource as a resource that is not under constraints (not fully utilized) and can change its output under small changes in the system either at a specific time period or integrally in several time periods. Marginal resources are a) a conventional generator or demand, which is unbounded, b) a generator limited by ramping constraints and unbounded before and after constrained time periods, c) a generator with a non-binding limited energy constraint, and d) a storage resource with non-binding state of charge.

Not all marginal resources form LMPs. We propose a definition of a price-forming resource as a resource whose offer or bid cost directly affects LMPs. Such resources are a)–c) ones mentioned above. Price-forming resources are not e) any resource with binding maximum or minimum output level constraints, f) a generator limited by ramping constraints and bounded before or after constrained time periods, g) a generator with a binding limited energy constraint, and h) a storage resource with fully utilized state of charge.

IV. LMP Formation

Writing (8) in an extensive form for each time period t, we have

$$(J_t^{node})^T \lambda_t^{node} + (J_t^{tc})^T \lambda_t^{tc} + (J_t^{vc})^T \lambda_t^{vc} = 0, \quad (24)$$

where λ_t^{node} consists of real and reactive LMPs at all nodes.

Equation (24) was comprehensively used to define spatial structure of LMP in the one-period market. According to [7], LMPs can be represented by LMP of marginal node through price-bonding factors (PBF) caused by power flow, transmission constraints, and voltage constraints:

$$\begin{aligned}\lambda_t^{pt} &= -\left[\left(J_t^{pt}\right)^T\right]^{-1}\left[\left(J_t^{pf}\right)^T \lambda_t^{pf} + (J_t^{tc})^T \lambda_t^{tc} + (J_t^{vc})^T \lambda_t^{vc}\right] \\ &= \Delta\lambda_t^{f} + \Delta\lambda_t^{tc} + \Delta\lambda_t^{vc}\end{aligned} \quad (25)$$

where λ_t^{pt}, λ_t^{pf} are price-taking and price-forming Lagrange multipliers in λ_t^{node}; J_t^{pt}, J_t^{pf} are corresponding to price-taking and price-forming Jacobian matrices derived in [7], and $\Delta\lambda_t^{f}, \Delta\lambda_t^{tc}, \Delta\lambda_t^{vc}$ are corresponding LMP components due to power flow, transmission and voltage constraints. This is schematically shown in Fig. 4 where resources of type a belong to a set of conventional marginal resources $\mathcal{A}_t$.

The knowledge of marginal price formation is based on the fact that marginal resources will respond to the incremental change in demand at node j. Their output change multiplied by marginal cost will define LMP at the node.

To take advantage of the methodology, it is necessary to determine the difference of $\lambda_t^{pf}, \lambda_t^{tc}, \lambda_t^{vc}$ for the one- and multi-period markets.

For any OPF model, we know that every shadow price of interest can be derived as

$$\lambda^{tc(vc)} = \partial f / \partial Lm^{tc(vc)}$$

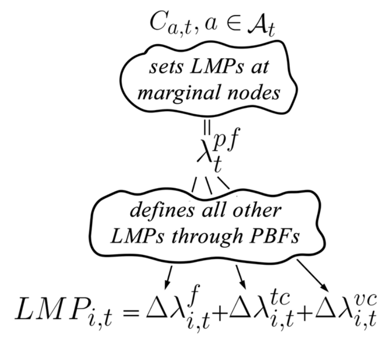


Fig. 4. Scheme of LMP formation without influence of intertemporal constraints.

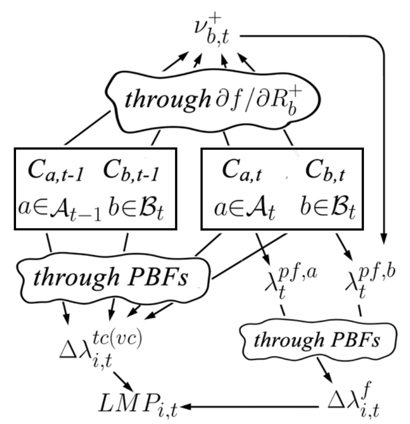


Fig. 5. Temporal scheme of LMP formation with influence of ramping rates.

$$\sum_{t\in\mathcal{T}}\left(\sum_{d\in\mathcal{D}} C_{d,t}\frac{\partial P_{d,t}}{\partial Lm^{tc(vc)}}-\sum_{g\in\mathcal{G}} C_{g,t}\frac{\partial P_{g,t}}{\partial Lm^{tc(vc)}}\right), \quad (26)$$

where *Lm* is the corresponding limit (maximum power flow, minimum or maximum voltage magnitude).

Unlike the one-period market, in the multi-period market the sum over time periods in (26) reveals the response of variable output of marginal and other resources in several time periods connected by intertemporal constraints. Thus, the transmission and voltage constraints components in LMPs are linked through PBF to different resources from different time periods.

As for price-forming LMPs λ_t^{pf}, furthermore, we consider different marginal and non-marginal resources with variable output and define price-taking LMP at their nodes under intertemporal constraints.

A. Influence of Ramping Rates

According to (11), LMP at a marginal generator under ramping constraints at a specific time period is diverted from a marginal cost. The reason is the use of other resources to meet the constraints. Knowing that

$$\nu_{g,t}^{\pm}=\frac{\partial f}{\partial R_g^{\pm}}=\sum_{t\in\mathcal{T}}\left(\sum_{d\in\mathcal{D}} C_{d,t}\frac{\partial P_{d,t}}{\partial R_g^{\pm}}-\sum_{g\in\mathcal{G}} C_{g,t}\frac{\partial P_{g,t}}{\partial R_g^{\pm}}\right) \quad (27)$$

$\lambda_{i,t}^{pf}$ at a corresponding marginal node can be represented as follows

$$\lambda_{i,t}^{pf}=C_{g,t}\pm\nu_{g,t}^{\pm}=\sum_{t\in\mathcal{T}}\sum_{r\in\mathcal{R}} k_{r,t}^{R_g^{\pm}} C_{r,t}\,, \quad (28)$$

where $k_{r,t}^{R_g^{\pm}}$ are the factors received from (27) plus one for the generator under consideration.

It is worth noting that partial derivatives $\partial P_{g,t(d,t)}/\partial R_g^{\pm}$ in the previous equation are nonzero only for marginal resources. For example $\sum_{t\in\mathcal{T}}\partial P_{g,t}/\partial R_g^{\pm}$ for non-marginal limited energy constraints will be equal to zero.

As a result, marginal LMP at the node of the considered generator is equal to its marginal cost plus marginal opportunity cost, namely, weighted costs of other marginal resources from the current and adjacent hours.

Substituting $\lambda_{i,t}^{pf}$ into (25), we find a new version of LMP component due to power flow. Note that the sensitivities obtained in (26) already take into consideration binding ramping constraints. The overall scheme of ramping rates influence for the time period t is shown in Fig. 5. Here the sets of marginal generators $\mathcal{A}_t, \mathcal{A}_{t-1}$ belong to conventional marginal generators of type a, while the set of marginal generators $\mathcal{B}_t$ refers to marginal generators of type *b* with binding ramping constraints. The similar scheme can be drawn for the time period *t*-1.

B. Influence of Limited Energy Constraints

As was said above, marginal generators with non-binding energy constraints are similar to conventional generators. Non-marginal limited energy generators are of more interest. They allow rescheduling generators in order to smooth out load variation. As a consequence, according to (15), such an ability of generator to shift its output to another time period with different hourly binding transmission, voltage, and other constraints allows us to form the same LMP at the limited energy generator node.

Rescheduling leads to selecting marginal resources with similar marginal costs during different time periods. It leads to the conclusion that LMP at the node of the limited energy generator comprises marginal costs at all time periods. PBFs for the LMP can be calculated for each time period and considered with weight of one divided by the number of such periods:

$$LMP_i=\sum_{r\in\mathcal{R}}\sum_{c=\{f,tc,vc\}} A\left(k_{r,t\in\mathcal{T}}^{c}\right)C_r\,, \quad (29)$$

where C_r here unifies same offer or bid prices for a resource *r* throughout the considered time period.

We can also consider a specific time period when there are no price-forming resources are present. For example, all generators with relatively low costs reach their maximum levels and other generators with relatively high costs are not utilized yet. The price in this case will be set by marginal generators from other time periods and transferred through the limited energy generator. The same refers to all time periods although the price-forming property is not apparent for the general case.

Thus, on the one hand, the limited energy resource cost is an opportunity marginal cost formed by actual marginal resources from all time periods, on the other hand, the limited energy resource transfers the received cost as an LMP at all specific time periods.

C. Influence of Energy Storage Constraints

The influence of the energy storage constraints on LMPs is similar to the influence of limited energy constraints yet with some differences. The first one is in two energy limited periods — charging and discharging periods. The second difference is that marginal or non-marginal storage resources reschedule conventional generators to provide LMP difference to be greater than or equal to its desired marginal cost. We recall that a marginal limited energy generator ceases to connect different hours while storage

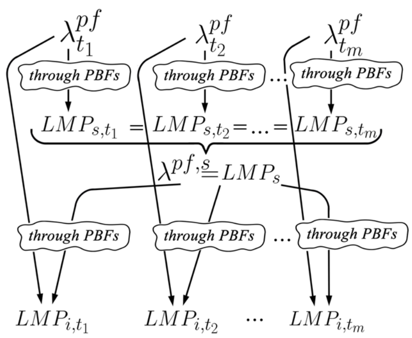


Fig. 6. Temporal scheme of LMP formation with influence of limited energy and energy storage constraints

continues to unite hoursdoing that independently of its status. Thus, all the above considerations on limited energy constraints can be applied to energy storage. In the overall scheme of limited energy constraints influence shown in Fig. 6, s denotes a limited energy generator, a storage generator, or a storage demand.

All the above considerations are summarized in Table I.

V. Illustrative examples

The proposed approach is demonstrated on the IEEE-30 power system with demands following a daily profile shown in Fig. 7. AC OPF was run in 24-hour periods from 0 to 23 hours usual for day-ahead markets.

All input and output data, as well as an exact mathematical model of the OPF problem and enumerated modifications in the test energy system, can be found in [33].

Table 1. LMP formation at marginal nodes

Resource	Status	Conditions to be met
Conventional	Extra marginal	$P_{g,t(d,t)} = \underline{P}_{g(d)}$, $LMP_{i,t} \le C_{g,t}$ or $LMP_{i,t} \ge C_{d,t}$
	Marginal	$\underline{P}_{g(d)} < P_{g,t(d,t)} < \overline{P}_{g(d)}$, $LMP_{i,t} = C_{g,t(d,t)}$
	Infra marginal	$P_{g,t(d,t)} = \overline{P}_{g(d)}$, $LMP_{i,t} \ge C_{g,t}$ or $LMP_{i,t} \le C_{d,t}$
Under ramping constraints	Extra marginal	$\underline{P}_g < P_{g,t} < \overline{P}_g$, $A(LMP_{i,t}) \le A(C_{g,t})$
	Marginal	$\underline{P}_g < P_{g,t} < \overline{P}_g$, $A(LMP_{i,t}) = A(C_{g,t})$
	Infra-marginal	$\underline{P}_g < P_{g,t} < \overline{P}_g$, $A(LMP_{i,t}) \ge A(C_{g,t})$
Energy limited	Extra-marginal	$\sum_{t\in\mathcal{T}} P_{g,t}\Delta t = \underline{E}_g$, $LMP_{i,t} = \sum_r \sum_c A(k^c_{r,t\in\mathcal{T}^*})C_r$, $\mathcal{T}^* = \{t: \underline{P}_g < P_{g,t} < \overline{P}_g\}$
	Marginal	Same as conventional[1]
	Infra-marginal	$\sum_{t\in\mathcal{T}} P_{g,t}\Delta t = \overline{E}_g$ $LMP_{i,t}$ is the same as for extra-marginal energy limited resource
Storage	Extra-marginal	$SC_{s,t} = \underline{SC}_s$
	Marginal	$\underline{SC}_s < SC_{s,t} < \overline{SC}_s$ For charging phase: $LMP_{i,t} = \sum_r \sum_c A(k^c_{r,t\in\mathcal{T}^{ch}})C_r$, $\mathcal{T}^{ch} = \{t: \underline{P}_d < P_{d,t} < \overline{P}_d\}$ For charging phase: $LMP_{i,t} = \sum_r \sum_c A(k^c_{r,t\in\mathcal{T}^{dch}})C_r$, $\mathcal{T}^{dch} = \{t: \underline{P}_g < P_{g,t} < \overline{P}_g\}$
	Infra-marginal	$SC_{s,t} = \overline{SC}_s$, $LMP_{i,t}$ is the same as for marginal storage resource

[1] Applicable for extra-marginal, marginal, and infra-marginal cases which are met during the considered time period

We will examine three cases. The first one shows LMP formation under the influence of ramping rates. The second case evaluates the change in LMP after placement of a limited energy generator in the system. The third case, on the contrary, assumes the introduction of a storage resource additionally to the first case.

A. Case 1: LMPs with Ramping Rates

For each of the six generators in the 30-node system we formulate several offers with different price levels and a capacity greater or equal to 10 MWh. At the same time, we set ramping rates to 5 MWh so that none of generators can freely increase or decrease its output. To introduce a diverse spatial LMP structure, we set a maximum active flow through line 6–8 to 25.4 MW. The results of the economic dispatch (1)–(4), specifically generators' schedule and LMPs, are shown in Figs. 8 and 9.

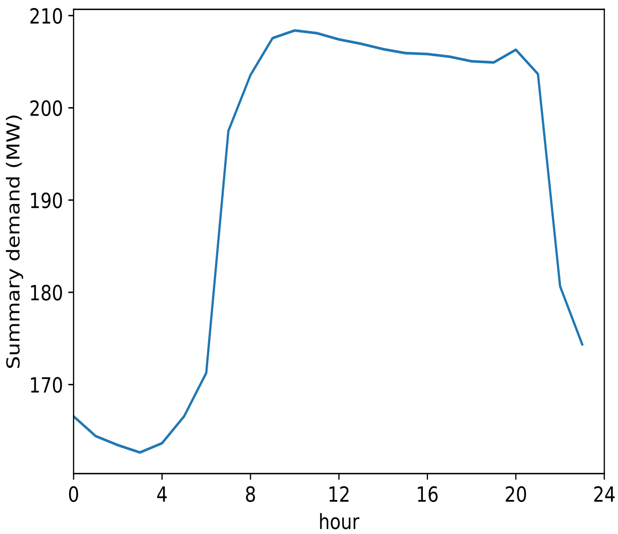


Fig. 7. Load hourly profile.

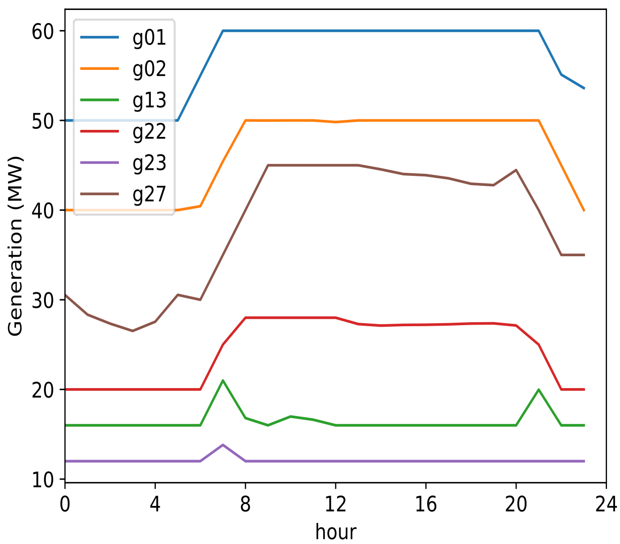


Fig. 8. Generator power output under ramping constraints in case 1.

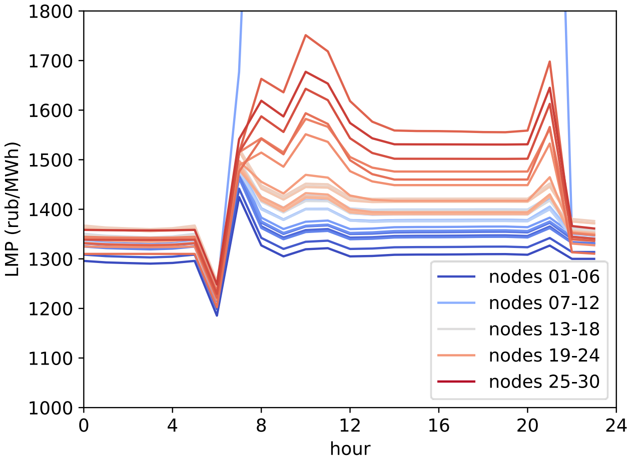


Fig. 9. LMPs under ramping constraints in case 1.

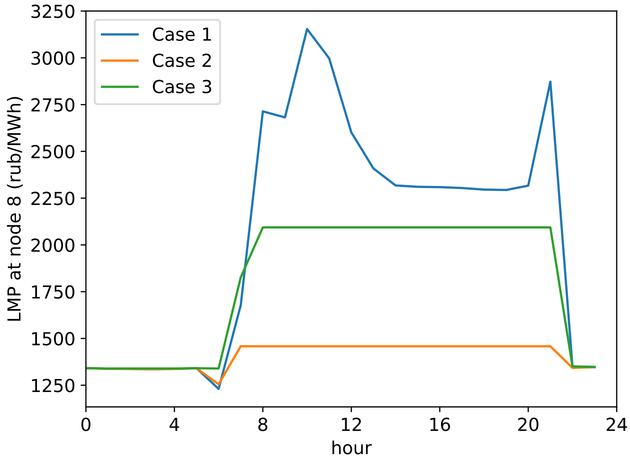


Fig. 10. LMP at node 8 in different cases.

Ramping constraints are hit in this case by generators 1, 2, 13, and 22 at hour 7 with ramp-up rate; by generator 27 at hours 7 and 8 with ramp-up rate; by generators 22 and 27 at hour 22 with ramp-down rate; by generator 2 at hours 22–23 with ramp-down rate. Only generator 2 became marginal under ramping constraints at hours 6–7. The other conventional marginal generators can be found in Table II.

LMPs at node 2 at hours 6–7 are 1198.39 and 1441.61 rub/MWh, respectively. Notably, average LMP is strictly equal to 1320 rub/MWh, which is marginal cost of generator 2. According to (11) and (28), and having $\nu^{+}_{2,7} = 0.974062\ C_{23,7} - C_{2,6} = 121.61$ rub/MWh LMPs at node 2 at hours 6–7 are formed in the following way:

$$\begin{aligned} LMP_{2,6} &= C_{2,6} - \nu^{+}_{2,7} = 2C_{2,6} - 0.974062C_{23,7} \\ LMP_{2,7} &= C_{2,7} + \nu^{+}_{2,7} = 0.974062C_{23,7} \end{aligned} \tag{30}$$

As to the other generators under ramping constraints, the LMPs at node of generator 1 are 1185.44 and 1424.56 rub/MWh, respectively. Average LMP is 1305.00 rub/MWh and it is higher than the marginal cost of 1300 rub/MWh.

Thus, generator 1 is infra-marginal. On the contrary, generator 13's LMPs are 1223.65 and 1477.04 rub/MWh, respectively, while its marginal costs are 1400 and 1450 rub/MWh, respectively. An average LMP of 1350.35 rub/MWh versus an average marginal cost of 1425 rub/MWh makes this generator extra-marginal.

Note that no generator actually has marginal costs below 1300 rub/MWh and that LMPs at hour 6 are formed at lower level by the only marginal generator under ramping constraints with the LMP of 1198.39 rub/MWh at marginal node. It is formed by two marginal costs of generator 2 at hour 6 and generator 23 at hour 7.

Note also that at hour 7, generator 23 is marginal at two nodes: 23 with a marginal cost of 1480 rub/MWh and 2 with a marginal cost of 0.974062·1480 rub/MWh. However, the set of replacing resources in general can vary.

All generators under ramping constraints need help to follow the demand, so the output of the most expensive offer of generator 23 (1480 rub/MWh) was raised at hour 7. At the adjacent hour 6, the cheapest offer of generator 27 (1310 rub/MWh) was decreased as far as it was allowed by ramp-up rates for its own output at 6–8 hours. Similar help is observed for falling load slope. Generator 13 (1400 rub/MWh) was chosen to help other generators 2, 22, and 27 to meet their ramping constraints.

As is seen from lower blue lines in Fig. 9, LMPs with ramping constraints form "cardiogram" curves. According to (11), the first period is characterized by LMP fall and the last period is characterized by LMP rise. We can also discern "cardiogram" curves for red lines at hours 7–8 where generator 27 met ramp-up rate. While respecting ramp-down rates we observe the opposite effect of an initial increase and then a decrease in the marginal LMPs.

Let us consider the spatial structure of LMP. The binding transmission constraint in line 6–8 divides the system into two parts at hours 7–21. Node 8's LMP has the highest positive transmission component — 860 rub/MWh and above. It is of interest to observe how it changes in different cases, which is shown in Fig. 10.

Other positive components due to the transmission constraint for nodes (red lines in Fig. 9) do not exceed 400 rub/MWh. In this example, transmission constraints act independently of intertemporal constraints despite the ramping connection inside of 6–8 hours. Transmission components are formed by hourly marginal costs as it

Table 2. Marginal generators under ramping constraints in case 1.

Generator	Hours	Marginal Cost	Type
g01	22–23	1300	a) conventional
g02	6–7	1320	b) ramping
	9, 12	1320	a) conventional
g13	8, 10–11, 21	1400	a) conventional
g22	13–20	1390	a) conventional
g23	7	1480	a) conventional
g27	0–5	1310	a) conventional
	14–20	1460	a) conventional

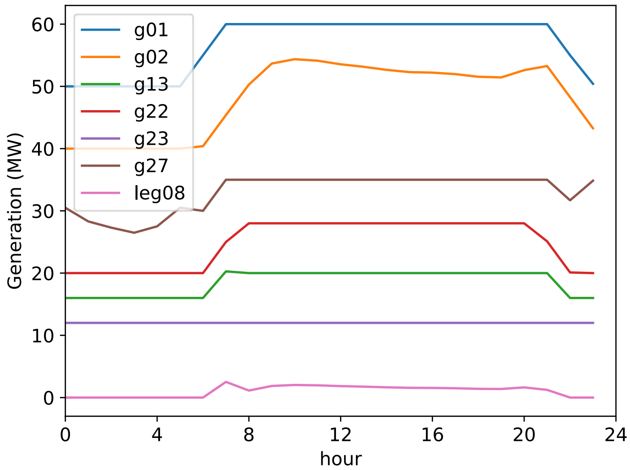


Fig. 11. Generator's power output under ramping constraints with limited energy generator (leg) in case 2.

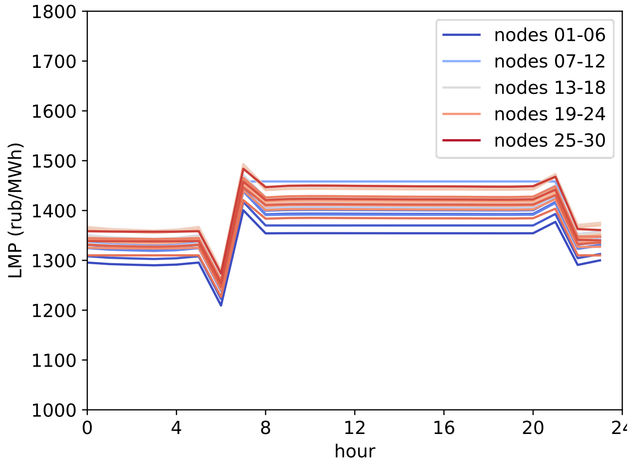


Fig. 12. LMPs under ramping constraints with limited energy generator in case 2.

is studied in previous research. There are also voltage components in a range of -2.12 to 0.03 rub/MWh. Due to small values, there is no need to rigorously study them.

B. Case 2: LMPs with Limited Energy Constraints

To further consider LMP at node 8, a limited energy generator with energy limit of 25 MWh was installed there. This generator can dispatch active power of less than or equal to 10 MW with a comparably low marginal cost. The generator provides the range of reactive power from –5 to 5 MVAr. LMPs and generators' output are shown in Figs. 11 and 12 while marginal generators are given in Table III.

The Figures show that the generators' output and LMPs are smoothed out during 8-20 hours. With the help of the new limited energy generator, the system is able to refuse high price offers of generators 13, 23, and 27 at hours 7–21, when the new generator is fully utilized replacing other resources.

As expected, there are less binding ramping constraints in the system. Ramp-up rates are achieved by generators 1, 2, 22, and 27 at hour 7. Ramp-down rates are reached by generators 1 and 22 at hour 22 and by generator 2 at hour 22–23. Nevertheless, the problem has not been solved. We can see from LMPs in Fig. 12 that the amplitude of the ramping "cardiogram" curve has remained the same. On the other hand, LMP at node 8 was lowered considerably

Table 3. Marginal generators under ramping constraints with limited energy generator in case 2.

Generator	Hours	Marginal Cost	Type
g01	23	1300	a) conventional
g02	6–7, 21–23	1320, 1370–1320	b) ramping
	8–20	1370	a) conventional
g13	7	1450	a) conventional
g22	21–22	1390	b) ramping
g27	0–5, 22–23	1310	a) conventional

(see Fig. 10), but the transmission constraint in line 6–8 is still binding.

The number of marginal generators under ramping constraints has increased. For example, generator 2 has become marginal with ramping type b during a 3-hour interval from hour 21 to hour 23. LMPs at node 2 at those hours are 1393.05, 1304.33, and 1312.62 rub/MWh, respectively. Offer prices are 1370, 1320, and 1320 rub/MWh, respectively. An average value of both price arrays is the same and is equal to 1336.66 rub/MWh. LMPs at the price-forming node 2 are formed taking into account the opportunity cost:

$$LMP_{2,21} = C_{2,21} + \nu^{-}_{2,22} = 1393.05,$$
$$LMP_{2,22} = C_{2,22} - \nu^{-}_{2,22} + \nu^{-}_{2,23} = 1304.33,$$
$$LMP_{2,23} = C_{2,23} - \nu^{-}_{2,23} = 1312.62,$$
$$\begin{aligned}\nu^{-}_{2,22} = {} & 0.803762\left(C_{2,22} + C_{2,23}\right) - 0.196238C_{2,21} \\ & +0.195997\left(C_{22,21} + C_{22,22}\right) - 1.001186C_{27,22} \\ & -0.689971C_{1,23} - 0.120668C_{27,23} \\ & -0.005732C_{13,7} = 23.05,\end{aligned}$$
$$\begin{aligned}\nu^{-}_{2,23} = {} & 0.887871C_{2,22} - 0.112129\left(C_{2,21} + C_{2,22}\right) \\ & +0.112075\left(C_{22,21} + C_{22,22}\right) - 0.762173C_{1,23} \\ & -0.133295C_{27,23} - 0.003237C_{27,22} \\ & -0.003358C_{13,7} = 7.38.\end{aligned}$$

Marginal cost $C_{13,7}$ (1450 rub/MWh) is connected with hours 21–23 through the binding energy limited constraint at hours 7–21. We can explain it by the following chain of events. The output of generator 13 at hour 7 should be slightly increased to lower the output of limited energy generator 8 at the same hour in order to support the ramping constraints of generator 2 at hours 22-23 by increasing its output at hour 21.

Let us consider the LMP formation at node 8 and its influence on price-taking LMPs during hours 7–21. The LMP is equal to 1458.33 rub/MWh. Price-forming resources make the following LMP components: $\Delta\lambda^{f}_{8,7-21} = 1418.05$, $\Delta\lambda^{tc}_{8,7-21} = 40.28$. Each of them is

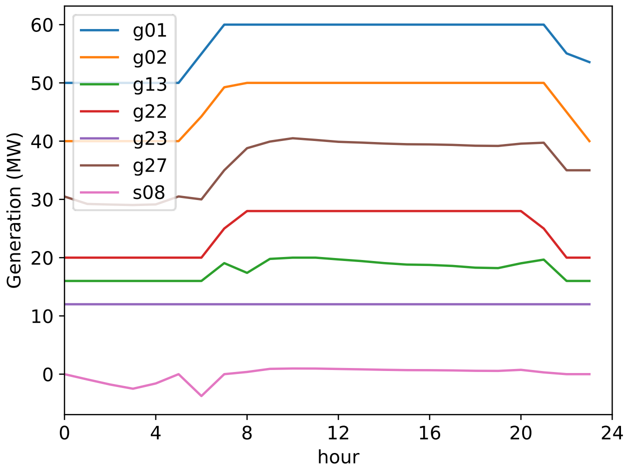


Fig. 13. Generator's power output under ramping constraints with storage (s) in case 3.

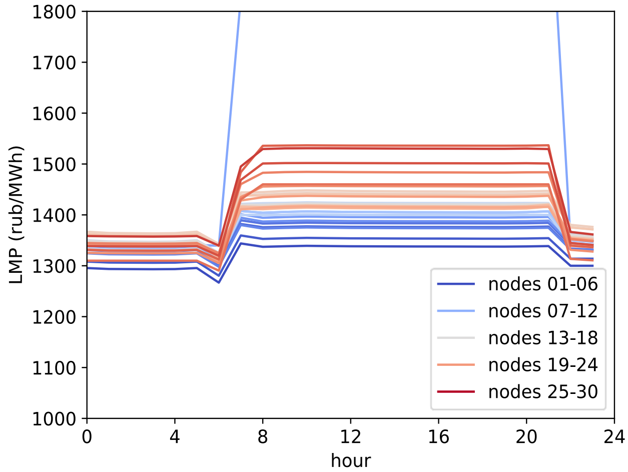


Fig. 14. LMPs under ramping constraints with storage in case 3.

connected with price-forming marginal costs through price-bonding factors. After determining the limited energy generator LMP at considered hours, we can make the next step and switch the status of the node to marginal. Its variable output is responsive to changes inside each time period. Node 8, being price-forming, makes spatial LMP structure at hours 8–20 clear. There are two price-forming nodes – each for zones of high and low LMPs under the influence of transmission congestion in line 6–8. Conventional marginal generator 2 supports incremental changes in demands and determines LMPs at nodes 1–7, 9–12 (blue lines in Fig. 12). An incremental change in demand for nodes 19–30 (red lines in Fig. 12) is handled by node 8.

C. Case 3: LMPs with Energy Storage

In case 3, we choose a storage resource to be installed at node 8 instead of the limited energy generator. The storage resource is defined by the following parameters: $\overline{SC}_s = 10$ MWh, $\eta_g = 1.01$, $\eta_d = 0.95$, $C_d = 0$, $C_g = 500$ rub/MWh. Optimization results after replacing the resource are shown in Figs. 13 and 14. Marginal generators are listed in Table IV.

The results show that the storage resource has a more significant effect on LMPs in comparison to a limited energy generator. The reason lies in the demand side. At hour 6, the demand of the storage resource has replaced increased output of generators 13 and 27 at hour 7 in case 1. This considerably reduced the effect of ramping constraints

Table 4 marginal generators under ramping constraints with storage in case 3

Generator	Hours	Marginal Cost	Type
g01	22–23	1300	a) conventional
g02	6–7	1320	b) ramping
g13	7–9, 12–21	1400	a) conventional
g27	0–5	1310	a) conventional
	8–21	1460	a) conventional

on LMPs. Nevertheless, as is seen from Fig. 10, the LMP at node 8 has not changed much because of a required marginal cost of the storage resource and its inefficiency.

Charging phase of the storage resource begins at hour 1 and continues until hour 6, excluding hour 5. During this phase, LMP is equal to 1339.37 rub/MWh and consists of $\Delta\lambda^{f}_{8,t_{ch}} = 1334.98$ and $\Delta\lambda^{tc}_{8,t_{ch}} = 4.39$. Discharging phase lasts from hour 8 to hour 21 with LMP formed to be 2093.75 rub/MWh. This LMP is composed of $\Delta\lambda^{f}_{8,t_{dch}} = 1464.33$ and $\Delta\lambda^{tc}_{8,t_{dch}} = 629.43$. Both LMPs are price-forming inside specific time periods.

Thus, they augment the list of marginal generators in Table IV with costs 1339.37 and 2093.75 rub/MWh, which in turn were comprised by given marginal costs of all connected hours.

VI. Conclusion

This paper proposes a new methodology to express Locational Marginal Prices (LMPs) as the sum of spatial components due to transmission and voltage constraints, and temporal components due to intertemporal constraints. The most common forms of intertemporal constraints are taken into consideration, namely ramping constraints, limited energy constraints, and storage constraints. The proposed approach is innovative in introducing a new definition of multi-period marginal and price-forming resources and a novel technique to uncover the dependence of the LMPs on various types of marginal resources from different time periods.

LMP decomposition is done for opportunity costs of marginal resources under intertemporal constraints. Each such resource brings marginal costs of adjacent periods multiplied by price-bonding factors into a current LMP structure. However, it is shown that the influence of the intertemporal constraints on the LMP varies considerably. Ramping constraints lead to "cardiogram" LMP curves. Limited energy and storage constraints smooth out the LMPs and price-bonding factors (PBFs) throughout the considered period. Although the marginal status of storage refers rather to LMP difference during high and low pricing periods.

This paper handles the multi-period AC OPF in order to calculate the LMPs, which helps to reflect intertemporal constraints in the system when determining the LMPs. The developed methodology provides a complex temporal structure of price signals that can support useful information about the profitability of placing additional resources to manage net load variability and system congestion. The methodology has been tested on a 30-node energy system.

References

[1] W. W. Hogan, "Contract networks for electric power transmission," J. Regul. *Econ.*, vol. 4, no. 3, pp. 211–242, 1992.

[2] W. W. Hogan, E. G. Read, and B. J. Ring, "Using mathematical programming for electricity spot pricing," *Int. Trans. Oper. Res.*, vol. 3, no. 3–4, pp. 209–221, 1996.

[3] M. Caramanis, R. Bohn, and F. C. Schweppe, "Optimal spot pricing: practice and theory," IEEE Trans. Power Appar. Syst., vol. PAS-101, no. 9, pp. 3234–3245, Sep. 1982.

[4] R. E. Bohn, M. C. Caramanis, and F. C. Schweppe, "Optimal pricing in electrical networks over space and time," *Rand J. Econ*., vol. 15, no. 3, pp. 360–376, Sep. 1984.

[5] F. Schweppe, M. Caramanis, R. Tabors, and R. Bohn, "Spot pricing of electricity. Boston: Kluwer", *Kluwer Academic Publishers*, 1988.

[6] T. Orfanogianni and G. Gross, "A General Formulation for LMP Evaluation," *IEEE Trans. Power Syst.*, vol. 22, no. 3, pp. 1163–1173, Aug. 2007.

[7] T. Vaskovskaya, P. Guha Thakurta, and J. Bialek, "Contribution of transmission and voltage constraints to the formation of locational marginal prices," *Int. J. Electr. Power Energy Syst.*, vol. 101, pp. 491–499, Oct. 2018.

[8] V. K. Singh and S. K. Singal, "Operation of hydro power plants-a review," *Renew. Sustain. Energy Rev.*, vol. 69, pp. 610–619, Mar. 2017.

[9] A. J. Wood, B. F. Wollenberg, and G. B. Sheble, "Power generation, operation, and control", 3rd ed., Wiley, 2013.

[10] M. T. L. Barros, F. T.-C. Tsai, S. Yang, J. E. G. Lopes, and W. W.-G. Yeh, "Optimization of large-scale hydropower system operations," J. Water Resour. Plan. Manag., vol. 129, no. 3, pp. 178–188, May 2003.

[11] O. Hoseynpour, B. Mohammadi-ivatloo, M. Nazari-Heris, and S. Asadi, "Application of dynamic non-linear programming technique to non-convex short-term hydrothermal scheduling problem," *Energies*, vol. 10, no. 9, pp. 1–17, Sep. 2017.

[12] C. P. Nguyen, M. Marwali, M. Swider, C. Rosecrans, and C. Sanada, "Limited energy resource optimization in the electricity market," in *Proc. IEEE Power and Energy Society General Meeting*, 2018, pp. 1–5.

[13] E. Barbour, I. A. G. Wilson, J. Radcliffe, Y. Ding, and Y. Li, "A review of pumped hydro energy storage development in significant international electricity markets," *Renew. Sustain. Energy Rev.*, vol. 61, pp. 421–432, Aug. 2016.

[14] "Electric storage participation in markets operated by regional transmission organizations and independent system operators," *Federal Energy Regulatory Commission, Fed. Regist.*, vol. 83, no. 44, pp. 9580–9633, 2018.

[15] A. Sakti, A. Botterud, and F. O'Sullivan, "Review of wholesale markets and regulations for advanced energy storage services in the United States: Current status and path forward," *Energy Policy*, vol. 120, pp. 569–579, 2018.

[16] J. Zhao, T. Zheng, and E. Litvinov, "A Multi-Period Market Design for Markets with Intertemporal Constraints," arXiv e-prints, pp. 1–12, Dec. 2018. [Online]. Available: http://arxiv.org/abs/1812.07034.

[17] S. Zaferanlouei, M. Korpas, J. Aghaei, H. Farahmand, and N. Hashemipour, "Computational efficiency assessment of multi-period AC optimal power flow including energy storage systems," in Proc. 2018 *International Conference on Smart Energy Systems and Technologies, SEST* 2018 - Proceedings, 2018, pp. 1–6.

[18] J. A. Taylor, "Financial storage rights," *IEEE Trans. Power Syst.*, vol. 30, no. 2, pp. 997–1005, 2015.

[19] D. Muñoz-Álvarez and E. Bitar, "Financial storage rights in electric power networks," *J. Regul. Econ., vol.* 52, no. 1, pp. 1–23, Aug. 2017.

[20] V. Popović, B. Jereb, M. Kilibarda, M. Andrejić, A. Keshavarzsaleh, and D. Dragan, "Electric vehicles as electricity storages in electric power systems," *Logist. Sustain. Transp.*, vol. 9, no. 2, pp. 57–72, Oct. 2018.

[21] A. Khodabakhsh, O. Papadigenopoulos, J. Matuschke, J. Horn, E. Nikolova, and E. Pountourakis, "Electric Vehicle Valet," arXiv e-prints, pp. 1–8, Nov. 2018. [Online]. Available: http://arxiv.org/abs/1811.06184.

[22] K. Bradbury, L. Pratson, and D. Patiño-Echeverri, "Economic viability of energy storage systems based on price arbitrage potential in real-time U.S. electricity markets," *Appl. Energy,* vol. 114, pp. 512–519, Feb. 2014.

[23] L. Yao, B. Yang, H. Cui, J. Zhuang, J. Ye, and J. Xue, "Challenges and progresses of energy storage technology and its application in power systems," *J. Mod. Power Syst. Clean Energy*, vol. 4, no. 4, pp.

519–528, Oct. 2016.

[24] C. K. Das, O. Bass, G. Kothapalli, T. S. Mahmoud, and D. Habibi, "Overview of energy storage systems in distribution networks: Placement, sizing, operation, and power quality," *Renew. Sustain. Energy Rev.*, vol. 91, pp. 1205–1230, Aug. 2018.

[25] P. Denholm, M. O'Connell, G. Brinkman, and J. Jorgenson, "Overgeneration from Solar Energy in California. A Field Guide to the Duck Chart," *Natl. Renewable Energy Lab., Tech. Rep*. NREL/TP-6A20–65023, Nov. 2015.

[26] "What the Duck Curve Tells Us About Managing a Green Grid," *California ISO, Shap. a Renewed Futur.*, pp. 1-4, 2015.

[27] B. Hua, D. A. Schiro, T. Zheng, R. Baldick, and E. Litvinov, "Pricing in multi-interval real-time markets," *IEEE Trans. Power Syst.*, vol. 34, no. 4, pp. 2696–2705, Jul. 2019.

[28] P. Zou et al., "Evaluating the impacts of flexible ramping products on the market equilibrium, in *Proc. IEEE Power Energy Soc. Gen. Meet*., 2016, pp. 1–5.

[29] A. Cornelius, R. Bandyopadhyay, and D. Patiño-Echeverri, "Assessing environmental, economic, and reliability impacts of flexible ramp products in MISO's electricity market," *Renew. Sustain. Energy Rev.*, vol. 81, no. 2, pp. 2291–2298, Jan. 2018.

[30] M. R. Davidson et al., "Mathematical model of power system management in conditions of a competitive wholesale electric power (capacity) market in Russia," *J. Comput. Syst. Sci. Int.*, vol. 48, no. 2, pp. 243–253, Apr. 2009.

[31] "General Information About Zagorskaya Hydtor Power Plant," RusHydro website. [Online]. Available: http://www.zagaes.rushydro.ru/pshpp/general/ (visited on 05/30/2019).

[32] E. Ela and M. O'Malley, "Scheduling and Pricing for Expected Ramp Capability in Real-Time Power Markets," *IEEE Trans. Power Syst*., vol. 31, no. 3, pp. 1681–1691, May 2016.

[33] T. Vaskovskaya. "IEEE-30 energy system data of multi-period market with intertemporal constraints," *Zenodo Repository,* DOI: 10.5281/zenodo.2702758, 2019.

Tatiana A. Vaskovskaya received the B.S., M.S. and Ph.D degrees from National Research University "Moscow Power Engineering Institute" (MPEI), Moscow, Russia. Currently, she is with MPEI and the Head of Analytical and OJSC "Trading System Administrator", Moscow, Russia. Her main interests include power markets, locational marginal pricing in full AC power flow framework, and data-driven applications in power markets.

Energy Security and Critical Facilities of Energy Systems: Methodology and Practice of their Identification on the Example of Russia's Gas and Electric Power Industries

Sergey Senderov*, Dmitry Krupenev

Melentiev Energy Systems Institute of Siberian Branch of Russian Academy of Sciences, Irkutsk, Russia

***Abstract* — The paper is devoted to the identification of energy system facilities that are critical in terms of national and regional energy security. Levels of critical facilities of the industry are substantiated and an algorithm for their inclusion in the lists of federal or regional critical facilities is developed. A simulation mathematical model of gas industry and a model for estimating the adequacy of the electric power system of Russia are used to estimate the role of the facility in the system availability. The study involves modeling of the operation of Russia's power and gas industries for the desired time interval given the factors affecting the operation of the systems. The proposed approach has been tested in the conditions of Russia's gas industry and the Interconnected Power System of Siberia. The result of the research is a list of critical facilities of the gas industry at the federal level, which includes, along with the facilities of gas transportation network, the main compressor stations of gas fields and underground gas storage facilities, as well as critical facilities of the Interconnected Power System of Siberia.**

***Index Terms* — gas industry, electric power system, critical facility, sys-tem availability, adequacy, energy security.**

* Corresponding author.
E-mail: ssm@isem.irk.ru

http://dx.doi.org/10.25729/esr.2019.02.0004
Received June 26, 2019.Revised September 05, 2019
Accepted October 11, 2019. Available online October 31, 2019.

I. Introduction

National energy development should meet energy security requirements. Broadly speaking, there are two major requirements. The first one is long-term deficit-free supply of the required types of fuel and energy resources (FER) to domestic consumers, and the fulfilment of the obligations to export Russian FER under normal operation of the energy sector. The second requirement implies providing the conditions for meeting the domestic demand for all the types of FER, and for FER export in case of emergencies in the energy sector. The emergencies in the energy sector mean partial or complete simultaneous failure of a limited number of facilities. It is also important to consider large-scale emergencies when energy facilities (or individual energy systems) in several areas or even federal regions have to operate under abnormal conditions, for example, under abnormally low temperatures or other large-scale external (with respect to the energy sector) impacts .

The second requirement necessitates well-grounded identification of critical facilities (CF) of the energy sector and of energy systems, i.e., identification of the facilities whose partial or complete failure can considerably reduce production capabilities of the energy systems or of the entire energy sector and result in shortage of relevant types of energy to be supplied to consumers. According to [1], CFs of the energy sector are the facilities whose partial or complete failure can result in inability to manage the economy of the Russian Federation, the economy of its entities or administrative-territorial units and in irreversible negative changes (destruction); or would pose a threat to population security. In terms of energy security, the identification of critical energy facility can be based on the following main negative consequences (in case of its considerable or complete failure): unacceptable losses suffered by consumers of final energy in case of undersupply of the required FER types.

The energy sector and energy systems in different periods may have different lists of critical facilities because the configuration of energy transmission systems, nodal loads of both consumers and producers change over time. Some facilities may lose their significance with time, whereas others more significant ones may emerge and their failure could be critical for production capabilities of the energy sector and energy systems of the country. An analysis of interrelated operation of energy systems within the energy sector allows finding out which CFs in the lists compiled for individual energy systems can be included in the list of CFs of the energy sector level. Negative consequences for consumers in case of a failure of a particular CF, given backup capabilities of the energy sector to reduce the negative consequences (FER interchangeability, diversification of their sources, etc.), can be a criterion for inclusion in such a list. Identification of critical facilities of the energy sector and compilation of their list make it possible to analyze and minimize the consequences due to different threats that may cause emergencies at the energy facilities, and to provide early preparation of CFs to operation under such conditions. It also allows concentration of material, financial and human resources to enhance the stability of the identified facilities operation and backup, when the resources are limited.

II. Present-day state of the critical facilities identification problem

This section presents a brief description of publications related to the issue. The focus of these publications is the identification of critical facilities in energy systems.

In [2, 3], the authors analyze a gas transport network to identify its critical units. The methodological approaches applied here are based on the topological network analysis with an accent on the issues of reliability and controllability. Such an analysis makes it possible to quantify the reliability of a gas transport network, and to estimate the role of each network component within various time intervals. As a case study, the authors present a real gas transport network in several EU countries. The paper presents the results of an analysis of such a critical infrastructure and shows the need to consider physical characteristics, such as limitations of the transmission capacity of gas pipelines. A special flow model was developed to estimate the aftereffects of negative external impacts on the gas supply to consumers. The vulnerability analysis is performed based on three aspects: global vulnerability analysis, demand robustness and critical pipeline analysis. The global analysis of vulnerability is performed considering possible disturbances at gas production and transportation facilities. The demand robustness analysis suggests assessing the ability of consumers to withstand external effects. In the critical analysis of gas pipelines, the authors address external factors affecting certain gas pipelines.

The authors of [4] present a method for identification and ranking of the critical components and their sets in technical infrastructures. The criticality of a component or a set of components is defined as vulnerability of a system to a failure of a certain component or a set of components. The paper also considers the problem of numerous simultaneous failures with synergetic aftereffects that complicate the problem. The proposed method allows solving this problem. As a case study, the authors propose a method for analyzing the distribution system in a Swedish municipality.

In [5], the authors propose a complex model for estimating the impact of interdependence between electric and gas systems on the reliability of power supply to consumers. The gas network operating conditions are modeled using constraints on the basic unit operation. Constraints on gas delivery may cause changes in the electric power industry operation. The case studies conducted by the authors proved that.

The authors of [6, 7] analyze possible impacts on the integrated gas and power networks. Failures in the gas system are shown to be more risky for an integrated energy system than failures in the power system. Therefore, the authors paid attention to possible control actions aimed at minimizing the negative effect of failures in the gas system. This approach can also be used for the cases when power is generated by gas-fired power plants.

The research aimed at finding the methods to reveal critical (weak points, bottlenecks) places in electric power systems (EPSs) was started long ago. Here we present some papers published recently. In [8], the authors describe a technique for identification of critical damages in EPS by modeling failures of its components with Monte-Carlo method. In [9], the method proposed by the authors to identify weak points in power system, employs a cascading failure model for EPS vulnerability analysis. Following the analysis of a sequence of emergencies, the authors of [10] propose identifying the EPS weak points using two dominating (according to their opinion) vulnerability indicators: the difference between actual power flow and maximum allowable power flow limited by steady-state stability margin, and the minimum number of sequential critical EPS states that make manual control inefficient. In [11], the authors use Fault Chain Theory to determine the stability loss of EPS and its weak points. This paper offers a new indicator for vulnerability assessment to identify critical transmission lines and vulnerable EPS sections that contribute to rapid propagation of the system's failure. Complex Network Centrality theory is used for identification of key EPS nodes. The authors of [12] present an algorithm and results of applying this theory.

The analyzed papers focus mainly on technical aspects of the problem. Their authors propose methods for identifying CFs in energy systems and in gas networks. Thus, they assign different indices to different facilities of a system, to determine the system vulnerability in case of a failure of a given facility. In this study, we suggest accentuating the significance of the analyzed object for the system operability, and clarifying the level of criticality for consumers if a certain object fails. The second level task is to determine the most critical situations for consumers under various combinations of failures in the system facilities.

Considering the previously gained experience, and based on an analysis of the research conducted worldwide, we developed an algorithm for compiling lists of critical energy system facilities that play an important role in operability of energy systems. This algorithm is exemplified by Russia's gas industry.

In this paper, critical facilities are identified for the gas industry of Russia represented by the Unified Gas Supply System (UGSS), and for the Unified Power System (UPS) of the country.

III. An Algorithm for Compiling a List of Critical Facilities in the Energy System

Natural gas is currently the major fuel in the fuel and energy balance of the country. Its share in the boiler and furnace fuel in Russia accounts for 74%. In Russia's European part and in the Urals (where 88% of the RF population live), this share exceeds 90%, and in some RF entities, it is as high as 98-99%.

The Unified Power System of Russia is a powerful infrastructure of the country, which provides joint operation of energy industries within a single energy sector, and connects them directly to final energy consumers.

On this basis, at the first stage of the critical facility identification we will give detailed consideration to the Unified Gas Supply System and an electric power system of Russia, and on their example discuss the issues of:

- Developing an algorithm for the identification of CFs in a particular system;
- Building a procedure for assessment of negative consequences for the considered energy system due to partial or complete loss of the identified critical facility, in case of different emergencies;
- Assessing the contribution of specific CFs in providing the availability of a certain energy system in emergencies;
- Developing a list of measures to minimize negative consequences caused by lower availability of each CF identified for the considered energy system.
- Substantiating a list of invariant measures to minimize negative consequences caused by different emergencies at CFs identified in the considered energy system, given possible combinations of emergencies at different facilities.

From the standpoint of energy security, the following two types of facilities can be recognized as CFs of an energy system:

- Facilities whose failure may cause considerable undersupply of certain FERs countrywide (deficit in the relative amount δ_{total} and higher with respect to the total demand of the country for this type of FER). Such facilities can be considered as CFs of federal level;
- Facilities that are not included in the list of federal CFs according to this system, whereas their failure may cause considerable undersupply of certain FER at least in one region (deficit in the relative amount δ_{reg} and higher with respect to the total demand of the region for this type of FER). Such facilities can be considered as CFs of regional level.

For example, earlier, in [13], δtotal for the gas industry was taken equal to 5%. The value of 30% could be used as δreg as a first approximation. It should be kept in mind that these values are rather conventional and special studies are needed for their complex substantiation for each energy system.

An algorithm for compiling a list of CFs for the regional and federal levels is given in Fig. 1.

IV. Characteristic of the considered gas network and mathematical problem statement

Let us consider a real situation in the gas industry of Russia. In 2018, gas production in Russia accounted for 725 bcm (natural gas and associate gas of oil fields), the amount of gas imported from Middle Asian countries made up 8 bcm. Domestic consumption in the same year (including auxiliary gas consumption by gas industry) amounted to 490 bcm, gas export accounted for 244 bcm, including a bit more than 194 bcm to the non-FSU countries [14].

Existing territorial structure of Russia's gas system has

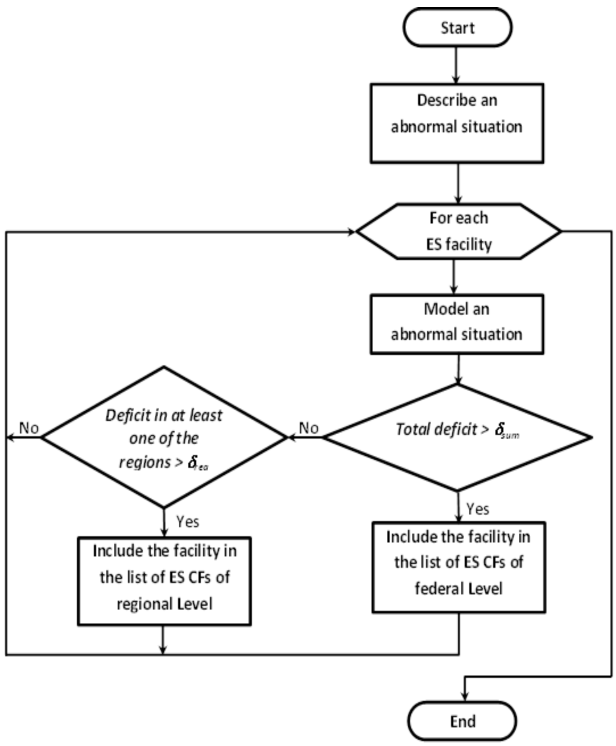


Fig. 1. An algorithm for compiling a list of CFs for the regional and federal levels of a particular energy system.

a number of notable drawbacks. The main domestic gas consumer, European part of the country, is located 2-2.5 thousand kilometers away from the gas production areas. More than 85% of Russian gas today is produced in the northern areas of Tyumen region (NATR). NATR gas is transported at long distances via multiple-line corridors with dramatic concentration of gas flows in one corridor. These corridors have a large number of intersections and joints. The lines within one corridor are sometimes located very close to one another. Today, there are more than 20 intersections of the main pipelines in Russia, which are potentially risky for the Unified Gas Supply System operation. Failure in some of them may reduce gas supply to domestic consumers throughout the country by 85% and lead to practically complete failure of gas export (subject to 50% reduction in gas supply to domestic consumers).

Previous studies [13, 15] showed critical facilities in Russia's gas system (20 intersections of the main pipelines). Meanwhile, the issue of including the remaining facilities of the gas industry in the list of critical from the standpoint of energy security was not considered. Along with a large number of intersections of the main pipelines at the nodal booster stations and outside them, the main compressor stations at the fields and underground gas storage facilities (UGSFs) are major facilities that ensure gas industry availability.

Currently, 22 UGSFs are in operation in Russia's gas transport system, 5 UGSFs of Gazprom Group operate outside Russia (3 in Belorussia, 1 in Armenia and 1 in Germany), 7 UGSFs (where Gazprom Group is a co-investor) are operated in the gas network of European countries. All those UGSFs are taken into account in a specially developed Gas Flow Model (within Oil and Gas of Russia software) [13, 15, 17] that allows an analysis of all the aspects of both the Unified Gas Supply System of Russia and Gas Transport Systems (GTS) of European countries that are technologically connected to it. The computational model contains 382 nodes, including the above UGSFs, 28 gas sources (in the model they are main compressor stations (CS)), 64 gas consumers, 268 nodal CS, and 628 arcs representing main pipeline corridors and individual main pipelines, and branches to distribution networks.

Mathematically considered related GTS is represented as a network changing in time. The nodes of this network have businesses of production, processing and consuming material flows serving as connections between the businesses. To estimate the system state after a disturbance, the minimum consumers' energy resource deficit at minimum costs of its delivery serves as an optimum flow distribution criterion.

Change in the system's facilities condition requires that the flow distribution problem be solved for the maximum energy carrier supply to the consumer, i.e., in this case, the model is formalized as a maximum flow problem [18, 19]. Calculation graph is completed with two fictitious nodes: O is an aggregate source, *S* is a total sink. Additional sections are introduced to connect node *O* with all the sources and all the consumers with node *S*. Mathematically, the problem has the form:

$$max\ f \quad (1)$$

subject to:

$$\sum_{i\in N_j^+} x_{ij} - \sum_{i\in N_j^-} x_{ji} = \begin{cases} -f, j=O \\ 0, j\neq O,S \\ f, j=S \end{cases} \quad (2)$$

$$0 \le x_{ij} \le d_{ij}, \text{ for all } (i, j) \quad (3)$$

Here N_j^+ is a subset of arcs 'entering' node *j*; N_j^- is a subset of arcs 'leaving' node *j*; *f* is a value of total flow in the network; x_{ij} is a flow over the arc (*i, j*); d_{ij} is constraints on flow in the arc (*i, j*).

Problem (1)-(3) on the maximum flow in the general case does not have a unique solution. The next step is solving the problem on maximum flow at minimum costs, i.e., minimization of the cost functional:

$$\sum_{(i,j)} C_{ij} x_{ij} \to \min \quad (4)$$

where C_{ij} is price or specific costs of the energy resource transportation.

A complex approach to solving the problems stated for the entire process chain of UGSS makes it possible to obtain an aggregate estimate of production capabilities of the entire system under extreme conditions. The solutions will be the determined potential for meeting the gas demand and possible gas undersupply to consumption nodes in case of an abnormal situation. These results can be used for compiling a list of facilities whose failure can cause potential gas deficit in the network. Let us rank this list based on the relative amount of gas deficit in the network. By excluding the facilities whose loss will lead to lower potential gas deficit in the network than the previously assigned value, e.g., 5%, we can get a list of CFs for the gas industry. This list should also be ranked based on the extent of impact on the network operability.

V. Results of studies on the gas industry

Relevant studies were performed using the above model of Russia's gas industry. Input conditions for the calculations are an average day of maximum gas consumption based on statistical data on gas consumption by region as of January 2018. Network operation on such a day can be considered to be at its maximum with respect to the average annual load. Total gas flow in the network on such a day, given gas export, made up around 2250 mcm. The results of the studies show that the potential gas deficit for consumers will be observed in case of a failure of 441 facilities of the Russian gas industry (242 nodes and 199 arcs of a network calculation graph). A threshold of the potential gas deficit (δ_{total} of 5% of the total gas demand) was exceeded by 61 facilities, with one facility failed. These facilities should be put on the CF list of federal level.

These facilities include 25 arcs between nodal compressor stations and 36 nodes that include 30 nodal compressor stations, five main compressor stations of large gas fields, and one UGSF. The calculated values of relative gas deficit in the network in case of failure of specific nodes and arcs that are ranked based on the gas deficit decrease are given in Table 1 (the actual names of the facilities are replaced by conventional numbers).

Data in Table 1 show that in case of shutdown of each of the first eight gas industry facilities from the list of CFs of federal level, relative gas deficit in the system can be around 20% of the total demand. Shutdown of each of subsequent 15 facilities may limit gas flow in the system by about 10-16%. Failure of all the other facilities from the CF list may cause 5-9% relative gas deficit in the system.

Table 1. Calculated relative gas deficits in the networks on the maximum gas consumption day of january 2018 in case of failure of facilities referred to federal critical facilities of UGSS

CF ordinal number in the ranked list	Facility type	Gas deficit due to CF failure, %
1, 2, 3, 4	Node	21
5, 6, 7	Arc	21
8	Node	19
9, 13, 14	Arc	16
10_a^*, 11, 12, 15	Node	16
16	Arc	12
17, 18, 19, 22, 23	Node	10
20 ,21	Arc	10
24	Node	9
25, 26, 28_a	Node	8
27	Arc	8
29, 31, 33, 35, 37, 39, 41	Arc	7
30_a, 32, 34, 36, 38, 40	Node	7
42, 48, 50	Arc	6
43_a, 44_a, 45, 46_b^{**}, 47, 49, 51	Node	6
52, 55, 56, 59, 60	Arc	5
53, 54, 57, 58, 61	Node	5

* - a node belongs to production facilities, i.e., to gas compressor stations at the gas fields;

** - a node belongs to underground gas storage facilities.

VI. Statement of the problem on identification and ranking of critical facilities of power system, and solving technique

Electric power system is a complex technological infrastructure characterized by a number of specific features to be considered when identifying its critical facilities:

- Operation of EPS varies within a year depending on power consumption and capacity utilization, which depend on the season. While identifying CFs, it is necessary to analyze all of them, as the facility significance can be revealed not only when power consumption is maximum. Moreover, the maximum power consumption in different areas may fall both on different days and on different months;
- Considering the consumption, it is advisable to take into account scheduled maintenances of energy equipment, since the maintenances render additional impact on the system operation, i.e., on the possible power shortage and electricity undersupply in case of an analyzed facility failure;
- Apart from the failure of the analyzed EPS facility within the calculated period, any other equipment in operation may fail, thus aggravating the situation.

According to the above said, to identify and rank the EPS CFs, it is advisable to use a model simulating EPS operation during a year taking into account all the factors that impact on the power shortage and electricity undersupply. A model for estimating the EPS adequacy is advisable to be taken as a basis for such a model [20]. This model simulates multiple operating conditions of EPS within a year using Monte-Carlo method in terms of scheduled and emergency maintenances, regular and random load fluctuations. The model consists of three computational blocks:

1. A block for developing the computed EPS states;
2. A block for identifying power shortages for the developed EPS states; Mathematical statement of this problem is as follows [5]:

Estimating the power deficit of the th EPS state, $k = 1, \ldots, N$ find

Table 2. Characteristics of reliability zones in ips of siberia

Node #	Node name	Annual load maximum MW	Available capacity MW	Own reserve MW	Own reserve % of P^H_{max}
1	Omsk EPS	1782	1479	-303	-17
2	Novosibirsk EPS	2690	2730	40	1.49
3	Tomsk EPS	1302	918	-384	-29.49
4	Altay EPS	1884	1444	-440	-23.35
5	Kemerovo EPS	4535	5028	493	10.87
6	Krasnoyarsk EPS	6235	12006	5771	92.56
7	Khakassia EPS	2155	5430	3275	151.97
8	Tyva EPS	152	40	-112	-74.01
9	Irkutsk EPS	7570	12550	4980	65.79
10	Bodaibo load center	90	20	-70	-77.78
11	Buryatia EPS	945	898	-47	-4.97
12	Trans-Baikalia EPS	1260	1156	-104	-8.25
	IPS of Siberia	30225[1]	43699	13474	44.58

* - a node belongs to production facilities, i.e., to gas compressor stations at the gas fields;

** - a node belongs to UGS facilities.

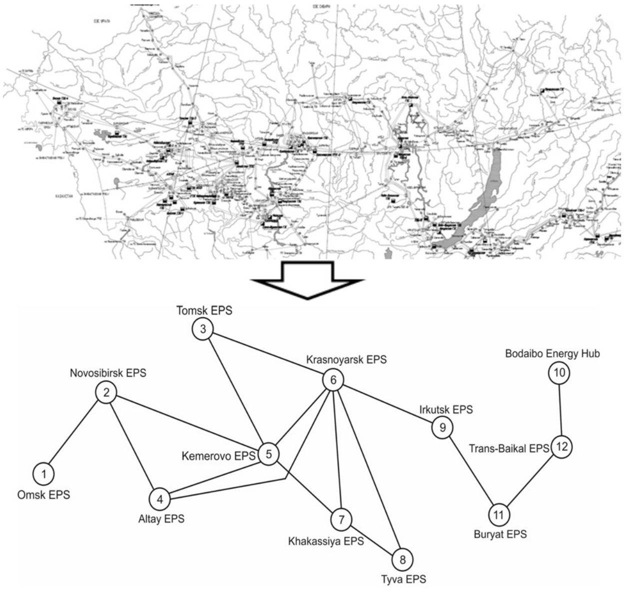


Fig. 2. Level of modeling the IPS of Siberia for CF identification.

$$\sum_{i=1}^{n} y_i \rightarrow \max \qquad (5)$$

Subject to the balance constraints

$$x_i - y_i + \sum_{j=1}^{n}(1 - z_{ji}a_{ji})z_{ji} - \sum_{j=1}^{n} z_{ij} = 0,\ i = 1, \ldots, n,\ i \neq j \qquad (6)$$

and linear inequality constraints on variables

$$y_i \leq \bar{y}_i^k,\ i = 1, \ldots, n, \qquad (7)$$

$$x_i \leq \bar{x}_i^k,\ i = 1, \ldots, n, \qquad (8)$$

$$z_{ij} \leq \overset{-k}{z}_{ij},\ i = 1, \ldots, n,\ j = 1, \ldots, n,\ i \neq j, \qquad (9)$$

$$y_i \geq 0,\ x_i \geq 0,\ z_{ij} \geq 0,\ i = 1, \ldots, n,\ j = 1, \ldots, n,\ i \neq j, \qquad (10)$$

where: x_i – available power at node i, $\bar{x}_i^k$ – available generating capacity at node i , y_i - load covered at node i , $\bar{y}_i^k$ - load at node i, z_{ij} , – power flow from node i to node j, $\overset{-k}{z}_{ij}$ – transfer capability of a power line between nodes i and j , a_{ij} specified positive coefficients of specific power losses at its transmission from node i to node j, $i \neq j$, $i = 1, \ldots , n$, $i \neq j$, $k = 1, \ldots , N$.

3. A block for computing the mathematical expectations of electricity undersupply and power shortage.

To identify and rank the EPS CFs, the following procedure is proposed:

1. Compile a list of EPS facilities to determine the mathematical expectation of power shortage and mathematical expectation of electricity undersupply in case of their failure. This can be done in several ways:
   - by sequential search of power plants and transmission lines within one facility;
   - by sequential search of EPS facilities assigned by experts.
2. Assess the adequacy of all the selected options for sequential search depending on the method selected at the first step.
3. Determine the mathematical expectations of power shortage and electricity undersupply for each option. The assessment can be made for any a priory specified time interval, namely, for a year, month, day, and hour.
4. Rank the results obtained.
5. Identify the facilities with the highest impact on the mathematical expectation of power shortage and electricity undersupply.
6. Identify and rank the EPS CF.

VII. Experimental studies on EPS CF identification

The process of EPS CF identification is demonstrated by the example of Interconnected Power System of Siberia. The interconnected Power System of Siberia (IPS of Siberia) is a large power interconnection within The Unified Power System of Russia. The IPS of Siberia includes large thermal and hydro power plants (TPP, HPP) and 220 and 500 kV transmission lines (TL). A schematic

Table 3. Transfer capabilities of inter-zone ties of IPS of Siberia.

Tie No.	Connected power systems	Transfer capability of a tie, MW
1	1. Omsk – 2. Novosibirsk	1305
2	2. Novosibirsk – 4. Altay	1440
3	2. Novosibirsk – 5. Kemerovo	950
4	3. Tomsk – 5. Kemerovo	1170
5	3. Tomsk – 6. Krasnoyarsk	780
6	4. Altay – 5. Kemerovo	950
7	4. Altay – 6. Krasnoyarsk	850
8	5. Kemerovo-6. Krasnoyarsk	1560
9	5. Kemerovo-7. Khakassia	1650
10	6. Krasnoyarsk-7. Khakassia	3400
11	6. Krasnoyarsk-8. Tyva	135
12	6. Krasnoyarsk-9. Irkutsk	3630
13	7. Khakassiya. Tyva	135
14	9. Irkutsk-11. Buryatia	885
15	10. Bodaibo load center – 11. Buryatia	66
16	11. Buryatia -12. Trans-Baikalia	410

* - a node belongs to production facilities, i.e., to gas compressor stations at the gas fields;

** - a node belongs to UGS facilities.

Table 4. Power plants of ips of siberia that were disconnected in the course of studies.

Node #	Node name	Power plant	Available capacity of PP, GW
1	Omsk EPS	TPP 5	0.73
2	Novosibirsk EPS	TPP 5	1.20
3	Tomsk EPS	JSC SHK	0.43
4	Altay EPS	Biysk TPP	0.51
5	Kemerovo EPS	Tom-Usinsk TPP	1.34
6	Krasnoyarsk EPS	Krasnoyarsk HPP	5.76
7	Khakassia EPS	Sayano-Shushenskoye HPP	5.33
8	Tyva EPS	Kyzyl TPP	0.17
9	Irkutsk EPS	Bratsk HPP	4.22
10	Bodaibo load center	Mamakan HPP	0.09
11	Buryatia EPS	Gusinoozersk TPP	1.16
12	Trans-Baikal EPS	Kharanorsk TPP	0.67

diagram of IPS of Siberia [5] and a transformed model of the IPS of Siberia for identification of its CFs is given in Fig. 2.

Division of the IPS of Siberia into reliability zones is done according to the division into the RF entities. The exception is the Bodaibo load center which formally belongs to the Irkutsk region but in fact is connected to the power system of the Republic of Buryatia (RB).

The reliability zone characteristics in the calculation model of IPS of Siberia are given in Table 2.

Transmission capacities of inter-zone ties in the calculation model of the IPS of Siberia are given in Table 2.

Transmission capacities of inter-zone ties in the calculation model of the IPS of Siberia are given in Table 3. To identify critical facilities in the IPS of Siberia, at the first stage we select (in an expert way) a number of power plants in the reliability zones and TL in the inter-zone ties whose loss will be modeled in the course of the studies. As reliability zone is a concentrated hub without constraints on the transfer capability, the largest power plants in each zone will make the highest contribution to the mathematical expectations of electricity undersupply and power shortage. Therefore, in the first stage of the experiment, we will sequentially disconnect the largest power plants in each zone. Characteristics of the disconnected power plants are given in Table 4.

Reliability zones of the IPS of Siberia were clustered following the principle of dividing the Russian Federation into entities, with the exception of Bodaibo energy system that administratively belongs to Irkutsk region but is actually connected to Buryat energy system.

As is seen from Table 5, in terms of power supply to consumers, only Mamakan HPP in Bodaibo load center can be referred to as the CFs of the IPS of Siberia. In the other reliability zones, the failure of the largest power plant did not result in higher electricity undersupply ei-ther in this zone or in the IPS of Siberia, i.e., the IPS of Siberia has sufficient generating capacity backup to meet the power demand in case of a failure of the largest power plants at each node of the considered system.

Similar failures were modeled at transmission lines of all the inter-zone ties of the IPS of Siberia. A series of calculations were performed with step-by-step disconnection of the largest line in each inter-zone tie. The transmission lines disconnected during the experiment are given in Table 6.

After a number of calculations, the values of mathematical expectation of electricity undersupply in the IPS due to a ‘failure’ of the indicated TL were obtained. The re-sults are given in Table 7.

As is seen from Table 7, the mathematical expectation of electricity undersupply in the IPS of Siberia changed negligibly. The values are high only in the case of failure of the largest TLs in the inter-zone ties Omsk-Novosibirsk, Bodaibo-Buryatia and Buryatia - Trans-Baikalia. As to the required power production of 663 billion kWh in the

Table 5. Effect due to disconnection of electric power plants in the reliability zones of IPS of Siberia.

Node	Node name	Math. expect. of electricity undersupply without power plants disconnection, kWh	Math. expect. of electricity undersupply after power plants disconnection, kWh	Math. expect. of electricity undersupply in the reliability zone where power plants were disconnected, kWh
1	Omsk EPS	3	29	0
2	Novosibirsk EPS	0	30	0
3	Tomsk EPS	0	26	0
4	Altay EPS	0	23	0
5	Kemerovo EPS	0	20	0
6	Krasnoyarsk EPS	0	23	0
7	Khakassia EPS	0	32	0
8	Tyva EPS	0	24	0
9	Irkutsk EPS	0	32	0
10	Bodaibo load center	0	401	358
11	Buryatia EPS	0	30	0
12	Trans-Baikalia EPS	24	30	27
System		27		

Table 6. A list of disconnected transmission lines.

Connected EPSs		Substation at TL start	Substation at TL end	TL voltage, kV
EPS name	EPS name			
Omsk	Novosibirsk	Tavrichesckaya	Barabinsk	500
Novosibirsk	Altay	Zarya	Altay	500
Novosibirsk	Kemerovo	Zarya	Yurga	500
Tomsk	Kemerovo	Tomsk	Novo-Anzhersk	500
Tomsk	Krasnoyarsk	Tomsk	Itat	500
Altay	Kemerovo	Barnaul	Novokuznetsk	500
Altay	Krasnoyarsk	Altay	Itat	500
Kemerovo	Krasnoyarsk	Novo-Anzhersk	Nazarovo TPP	500
Kemerovo	Khakassia	Novokuznetsk	Sayano-Shushenskoye HPP	500
Krasnoyarsk	Khakassia	Abakan	Itat	500
Krasnoyarsk	Tyva	Ergaki	Turan	220
Krasnoyarsk	Irkutsk	Kamala	Taishet	500
Khakassiya	Tyva	Abaza	Ak-Dovurak	220
Irkutsk	Buryatia	Klyuchi	Gusinoozersk TPP	500
Bodaibo	Buryatia	Taksimo	Mamakan	220
Buryatia	Trans-Baikalia	Gusinoozersk TPP	Petrovsk-Zabaikalsky	220

Table 7. Mathematical expectation of electricity undersupply in the IPS of Siberia due to a failure of TL in the inter-zone ties, kWh/ power demand ratio, % (node numbers corre-spond to their numbers in the previous Tables).

Node	2	4	5	6	7	8	9	11	12
1	3027 /0.45	-	-	-	-	-	-	-	-
2	-	29 /0	32 /0	-	-	-	-	-	-
3	-	-	22 /0	31 /0	-	-	-	-	-
4	-	-	40 /0	46 /0	-	-	-	-	-
5	-	-	-	24 /0	33 /0	-	-	-	-
6	-	-	-	-	28 /0	46 /0	35 /0	-	-
7	-	-	-	-	-	42 /0	-	-	-
9	-	-	-	-	-	-	-	47 /0	-
10	-	-	-	-	-	-	-	602 /0	-
11	-	-	-	-	-	-	-	-	295 /0

entire IPS, the 'failure' of the above TLs does not lead to considerable changes. Locally, however, for the reliability zones connected by the above given TL, their 'failure' can result in considerable elec-tricity undersupply.

Thus, the analysis of the IPS of Siberia in terms of critical facilities from the energy security perspective re-vealed that in the present-day contexts, Mamakan HPP and 500 kV Tavricheskaya-Barabinsk TL; 220 kV Taksi-mo-Mamakan TL; and 220 kV Gusinoozersk TPP - Pe-trovsk-Zabaikalsky TL could be referred to as CFs of EPS of regional level.

VIII. Conclusion

This paper has demonstrated the examples of imple-menting the approaches to the identification of critical facilities of energy systems in Russia's gas and electric power industries. A list of CFs has been developed for the gas industry. As to the power industry, an analysis of the situation in the IPS of Siberia has shown that the IPS of Siberia has sufficiently high reserves both in terms of generating capacities, and in terms of networks. Howev-er, the studies have revealed a number of CFs that have to be paid special attention to while planning the expansion of the IPS of Siberia.

The facilities identified during the studies should be paid thorough attention to in order to provide the sur-vivability of the gas industry, the entire energy industry and, subsequently, energy security of the country and its regions. Organizational measures should be taken to prevent emergencies, primarily at those facilities. The strategic objectives of developing the industries analyzed may include identification of directions and ways for re-ducing the significance of relevant CF in the potential ES availability. After gaining the experience in identifying the CFs in the gas and energy industries, the studies could be extended to identifythe CFs in other energy systems, and in the energy sector as a whole.

Acknowledgments

The research was carried out under State Assignment Project III.17.5.1. (reg. no. AAAA-A17-117030310451-0) of the Fundamental Research of Siberian Branch of the Russian Academy of Sciences and partly supported by the Russian Foundation of Basic Research, Grant No. 18-58-06001

References

[1] Federal Law as of July 21, No. 256-FZ "On Security of FEC Facilities," (in Russian.)

[2] Han F. & Zio E. & Kopustinskas V. & Praks P. Quantifying the importance of elements of a gas transmission network from topological, reliability and controllability perspectives, considering capacity constraints. In book: Risk, Reliability and Safety: Innovating Theory and Practice, 2016, pp. 2565-2571. DOI 10.1201/9781315374987-389,

[3] Su H., Zio E., Zhang J. Li X. A systematic framework of vulnerability analysis of a natural gas pipeline network. Reliability Engineering & System Safety, Vol. 175, July 2018, Pages 79-91 https://doi.org/10.1016/j.ress.2018.03.006.

[4] Jonsson H., Johansson J., Johansson H. Identifying critical components in technical infrastructure networks. Proceedings of the Institu-tion of Mechanical Engineers, Part O: Journal of Risk and Reliability, Vol. 222. No. 2. P. 235-243, 2008, https://doi.org/10.1243% 2F1748006XJRR138.

[5] Li T., Eremia M., Shahidehpour M. Interdependency of natural gas network and power system security, IEEE *Transactions on Power Systems*, vol. 23, 1817-1824. https://doi.org/10.1109/ TPWRS.2008.2004739.

[6] Dokic S.B., Rajakovic N.Lj. Security Modelling of Integrated Gas and Electrical Power Systems by Analyzing Critical Situations and Potentials for Performance Optimization, *Energy*, DOI: 10.1016/j.energy. 2018.04.165.

[7] Fershalov Yu.Ya., Fershalov M.Yu., Fershalov A.Yu. *Energy efficiency of nozzles for axial microturbines, Procedia Engineering*, vol. 206, 499-504, 2017.

[8] G. Vancells, S. Herraiz, J. Meléndez, Á. Ferreira Analysis of Importance of Components in Power Systems using Time Sequential Simulation/ Proceedings of International Conference on *Renewable Energies and Power Quality (ICREPQ'13)* Bilbao (Spain), 20th to 22th March, 2013.

[9] Hanbo Qi, Libao Shi, Yixin Ni, Liangzhong Yao, Bazargan Masoud Study on power system vulnerability assessment based on cascading failure model. Proceedings of 2014 *IEEE PES General Meeting | Conference & Exposition*, 27-31 July 2014, DOI: 10.1109/PESGM.2014.6939071.

[10] Hillberg E., Lamponen J., Haarla L., Ritva Hirvonen Fingrid Oyj, Helsinki, Finland Revealing stability limitations in power system vulnerability analysis, Proceedings of 8th Mediterranean Conference on Power Generation, Transmission, Distribution and Energy Conversion (MEDPOWER 2012), DOI: 10.1049/cp.2012.2027.

[11] Ansi Wang, Yi Luo, Guangyu Tu, Pei Liu Vulnerability As-sessment Scheme for Power System Transmission Networks Based on the Fault Chain Theory, *IEEE Transactions on Power Systems*, Vol. 26 , Issue: 1 , Feb. 2011 DOI: 10.1109/TPWRS.2010.2052291.

[12] Bin Liu, Zhen Li, Xi Chen, Yuehui Huang, Xiangdong Liu Recognition and Vulnerability Analysis of Key Nodes in Power Grid Based on Complex Network Centrality, *IEEE Transactions on Circuits and Systems II: Express Briefs*, Vol. 65 , Issue: 3 , March 201, DOI: 10.1109/TCSII.2017.2705482.

[13] Senderov S.M., Rabchuk V.I, Edelev A.V. Peculiarities of developing a list of critical facilities in the gas transportation system of Russia with account of energy security requirements and possible measures to minimize negative consequences caused by emergencies at such facilities, Izvestiya RAN. *Energy*, No. 1, pp. 70-78, 2016, (in Russian.)

[14] https://minenergo.gov.ru/activity/statistic, date of the application 10.05.2019, (in Russian.)

[15] Senderov S., Edelev A. Formation of a list of critical facilities in the gas transportation system of Russia in terms of energy security. *Energy*, 2017, doi:10.1016/j.energy.2017.11.063.

[16] PAO Gasprom: Underground gas storage facilities [Digital resource] URL: http://www.gazprom.ru/about/production/underground-storage/ (date of reference 19.04.2018).

[17] Voropai N.I., Senderov S.M., Edelev A.V. Detection of "bottle-necks" and ways to overcome emergency situations in gas transportation networks on the example of the European gas pipeline network. *Energy*, 2012, doi:10.1016/j.energy.2011.07.038.

[18] Khramov A.V., Enikeeva S.M., Khrustaleva N.M., et. al. Software and information support for solving the survivability problems of the USSR Unified Gas Supply System,Methods and models for energy systems survivability studies, Novosibirsk: *Nauka*, Sib. Div., pp., 86-91, 1990, (in Russian.)

[19] Ford L.R., Fulkerson D.R. and J, Flow in the networks / Transl. from English, M.: Mir, 1966, 276 p.

[20] Kovalev G.F., Lebedeva L.M. Reliability of Power Systems. *Springer Nature Switzerland AG*, 237 p., 2019.

Sergey Senderov graduated from Irkutsk Technical University in 1986. He is a Doc-tor of Engineering, Head of Energy Security Department and Deputy Director of the Melentiev Energy Systems Institute of Siberian Branch of the Russian Academy of Sciences . His research interests are energy security, threats and indicators of energy security, reliability of energy systems and of fuel-energy supply.

Dmitry Krupenev graduated from Irkutsk State Academy of Agriculture, Department of Energy, in 2007. In 2011, he received the degree of Ph.D. in Engineering, from the Melentiev Energy Systems Institute of Siberian Branch of the Russian Academy of Sciences. Since 2011, he has been Head of a Laboratory at ESI SB RAS. His research interests are reliability of energy systems, renewable energy, and energy security.

Imperfection Of Electricity Markets

Lev Belyaev*

Melentiev Energy Systems Institute of Siberian Branch of Russian Academy of Sciences, Irkutsk, Russia

***Abstract* — The paper shows the imperfection (in terms of microeconomics) of markets organized in the electric power industry. This imperfection is caused by special properties of the electric power systems (EPSs) that underlie the power industry. An analysis presented in the paper shows that these properties make it impossible to create conditions for perfect competition in the electricity markets. The imperfect markets require Government regulation of trade, including pricing. Deregulation of prices leads to negative consequences, which is the case in the power industry of Russia.**

***Index Terms* — Electricity markets, electyic power systems.**

I. Introduction

At the end of the 20th century, many countries of the world started restructuring their electric power industry with the organization of one or another type of market. Before this, in most of these countries, power industry was a regulated natural monopoly, i.e. an industry in which positive scale effect was so large that one firm could produce all products (electrical energy) at lower costs and prices than two or more firms. In other words, it was economically advantageous to have one company, and, for this company not to abuse its monopoly position, to introduce government regulation of its activities, including the establishment of rates for electricity supplied to the consumer.

In the early 1990s, during the privatization of state property, Russia organized the federal wholesale electricity market according to the "Single Buyer" model (see below), and then, in 2001, after the Russian Government issued Resolution No. 526, the transition to a competitive market began (with unregulated prices) [1]

* Corresponding author.
E-mail: belyaev@isem.irk.ru

http://dx.doi.org/10.25729/esr.2019.02.0005
Received May 15, 2019. Revised June 23.
Accepted July 12, 2019. Available online November 15, 2019.

There are four main models of electricity markets that were established in different countries during the reform (they will be listed in the paper). In two of them (a regulated monopoly and a single buyer), the state regulates electricity prices. The two other models have a fundamental difference – there is no price regulation (deregulation) in the wholesale market or wholesale and retail markets. This deregulation of prices, which is effective and admissible only when competition in the market is perfect, is the main focus of this paper. These two models with free-of-control prices will be called competitive markets. The question is if it is possible to provide perfect competition in electricity markets and switch from regulated markets to competitive ones?

The causes of reforms in the electric power industry and the goals posed are country-specific. In developing countries reforms were a result of insufficient governmental funds to ensure the required power development, and the main goal, therefore, was to attract private (including foreign) investments. Some countries, however (for example, China and India), retained the regulation of electricity prices, as their liberation under the conditions of power shortage was just impossible. These countries did not deregulate the industry, i.e., did not make a transition to a competitive market. At the same time, some other countries (for example, Chile, Argentina, and Brazil) created competitive wholesale electricity markets.

In the majority of developed countries, the main cause of reforms was high electricity prices, and the reforms aimed to decrease them. Competition in electricity generation and sales was expected to enhance the efficiency and decrease production costs and, hence, the prices for the final consumers. Many developed countries (England, some states in the USA, Australia, and Scandinavian countries) have deregulated their power industries and organized competitive wholesale and retail markets with free prices.

Meanwhile, the experience of the past years [2–12] shows that electricity deregulation (or liberalization) often leads to the opposite results, i.e., to a price rise, lack of investments, power shortage, and decrease in electricity supply reliability (including blackouts). The initial concepts of reforms are revised (reform of the reforms), the process of reforms is delayed (none of the countries has completed reforms), electricity markets grow more complicated, the proposals are put forward to restore regulation, etc.

The main goal of this paper is to show a general imperfection of the electricity market, the flaws of the competitive market, and the necessity (inevitability) of state electricity price regulation. The problems arising from the deregulation of electricity markets include:

- An increase in the wholesale electricity prices from the level of average costs throughout the EPS (under price regulation) to the level of costs of the least efficient (marginal) plant. This leads to additional expenses for consumers and extra profits (so-called producer's surplus) for power generation companies (PGCs).
- Difficulties in financing the construction of new power plants, including the "price barrier" to new power producers, which may cause a capacity shortage and a greater wholesale price increase. This will place a further burden on electricity consumers, whereas producers will start to get a monopoly profit.

These and many other problems will be discussed in the paper. At first, the effects of the creation and integration of electric power systems will be shown. These effects are largely determined by the special properties of electric power systems, which determine the imperfection of the electricity markets and their differences from markets in other industries. An individual section of the paper is devoted to the EPS properties and their influence on various market models. Then, the conditions (requirements) under which perfect competition in the markets is ensured, and the possibilities (or rather impossibility) of their implementation in the electric power industry are specified in detail.

The paper relies on the studies conducted by the author ([13-22]), as well as publications of researchers from Russia and other countries.

II. Benefits of creating and interconnecting EPSs

It is well known (see, for example, [23–26]) that some objective reasons and factors have given rise first to the creation of, and increase in EPS capacity with an extension of the territory served and then to the expediency of their interconnection. On the whole, they impart a distinctive economic property to EPSs—economies of scale, i.e., an integral effect of a decrease in costs of production, transportation, and distribution of electricity (and its price) with growing EPS sizes. This property is seen in the case of both individual EPSs and their integration, encouraging the creation of power interconnections of increasingly higher levels.

Let us consider at first the factors contributing to the formation and expansion of EPSs. Among them are the following:

• *A decrease in the required capacity reserves.* The increase in the total number of power units is known to decrease the probability of simultaneous emergencies of their specified share (percentage) (see, for example, [27]). As a result, the share of standby units to ensure the same reliability level of the power supply is reduced with the growth of their total number. This concept is illustrated quantitatively in [24] Dependence of the required emergency reserve on the total installed capacity of EPS proves to be nonlinear, namely, the reserve required increases to a lesser extent than does the total capacity of EPS. This objective regularity gave impetus to EPS formation, increase in EPS capacity and territorial coverage, as well as the interconnection of EPSs.

Here we note the following factors:

— The considered effect is achieved by the increasing the number of units regardless of their capacity, i.e., the "scale" in this case emerges in the growing number of units (blocks) of power plants, rather than in their capacity.

— The effect is realized by the construction of transmission lines interconnecting power plants and consumer substations into the unified whole. Hence, this effect is typical of an EPS as a whole—in the interaction between the spheres of electricity generation and transportation (distribution).

— With an increase in the size (total capacity and area) of an EPS and preservation of its integrity, the effect will "fade away," i.e., it will decrease in the relative value but continue to increase in the absolute one. This regularity can be violated by splitting the EPS into spheres and the spheres into several individual companies.

• *Improvement in specific economic indices of EPS facilities* with the enlargement of power plants and an increase in transfer capabilities of transmission lines. This trend is well known. It showed up in the process of EPS dimensions growth when it became possible (and economically sound) to construct power plants of higher capacity with larger units and higher voltage transmission lines. At present, the unit capacity of blocks of coal-fired steam turbine plants and nuclear power plants with thermal reactors has virtually reached its economic limit. Further increase in their capacity does not lead to a decrease in their specific capital investments. However, it is still reasonable to construct such power plants with blocks of high (economically sound) unit capacity, if their commissioning is needed for the optimal EPS structure. Of special importance are hydropower plants (HPPs), whose capacity depends on specific river conditions (water heads and flow rates); gas-fueled combined cycle power plants (CCPPs), whose rather low specific investments can be achieved at low capacities of blocks; and also nuclear power plants (NPPs) with fast reactors, whose unit capacity has not yet reached an economic limit. The transfer capability of transmission lines, especially DC lines, can also increase.

Note that this factor is often considered as economies of scale in the electric power industry. It is asserted, in particular (for example, in [28]), that with the appearance of CCPPs the economies of scale have been lost. However, this is not so. Firstly, this factor is one of many considered here. Secondly, the emergence of highly cost-effective CCPPs cannot lead to the "destruction" of EPSs or stop the increase in their dimensions. CCPPs, on the contrary, increase the variety of types of generation capacities and possibilities for the creation of their more optimal structure, i.e., enhance the overall efficiency of electricity generation, in particular at EPS expansion.

Construction of CCPPs by independent power producers (IPPs) in regulated monopolies is a special case. The high efficiency of CCPPs makes it possible for IPPs using them to successfully compete with monopoly companies. In this situation, it is expedient to connect IPPs to the EPS networks owned by the monopoly company and conclude corresponding contracts for electricity supply. Such a condition is laid down by the Law in many countries (the USA, Japan, China, etc.). At the same time, the monopoly companies themselves can construct CCPPs, which is practically the case.

• *Improvement in economic indices of EPS as a whole owing to the technological progress in any sphere of electricity production, transportation, or distribution.* The impact of technological progress is observed constantly and the EPS (as a system) “accumulates” the effects achieved in any of the spheres. Specific technological innovations are highly diverse. However, on the whole, they improve the EPS efficiency (reduce electricity prices and tariffs for final consumers) and contribute to the growth of their scales in both territory and capacity. Examples of the latest achievements in technological progress are the creation of the aforementioned highly efficient CCPPs and the design of the FACTS (Flexible Alternating Current Transmission Systems), increasing transfer capability and controllability of AC transmission lines (see, for example, [29]).

When an EPS is split into spheres and numerous independent companies, as is the case at the transition to the competitive market, the effect of technological innovations can “remain” in the companies and not “apply” to consumers.

• *Optimization of structure, schemes, and operating conditions of EPSs*, whose possibility (and necessity) enhances the economic efficiency of power supply to consumers, reduces costs in the system and electricity prices. Optimization implies the selection of the most economically efficient power plants and transmission lines and the best modes of their usage. This factor, therefore, contributes to the formation of EPSs and assists their expansion (an increase in EPS dimensions).

• *A decrease in the share of administrative expenses* with the growth of EPS scales, which is typical of vertically integrated companies that monitor the whole system. Such a trend occurred everywhere in the last century. Nowadays, in the countries entering the competitive market, in which the single monopoly companies are split into sets of generating, network, and sales companies, these expenses have not fallen but risen instead.

In general, as was already mentioned, the indicated factors create economies of scale, providing an incentive for the formation of EPSs, successive increase in their capacity, and territorial expansion. In the planned economy countries (including the USSR), this process was centrally managed. In the market economy countries, in the first half of the twentieth century, it brought the *natural monopolies* in the electric power industry into being that should be regulated by the State to prevent them from taking advantage of their monopoly position. Formation of the regulated natural monopolies was a structural transformation of the electric power industry in these countries in comparison with the free market that existed there previously. The deregulation of the power industry taking place in some countries is a reverse transformation (return to the competitive, though institutionalized, market). Now, we pass on to the *effects owing to the interconnection of EPSs* with the formation of interconnected EPSs (IPSs) within one country and the unified or national EPS of the country (UEPS or NEPS). These effects are also well known and studied. Therefore, they will be commented on briefly. Part of the effects is due to the same factors that were mentioned above; however, there are specific factors as well.

The key effects achieved owing to the interconnection of EPSs are as follows [24]:

1. Power transfer from an EPS with cheaper electricity to an EPS with a more expensive one
2. Reduction in the required emergency and repair capacity reserves
3. A decrease in coincident maximums and leveling of the joint load curves of consumers
4. Possibility of constructing large-scale power plants with larger units
5. Rationalization (coordination) of putting into operation large power plants in EPSs to be interconnected
6. Improved usage of power plants when interconnecting EPSs with different structures of generation capacities
7. Environmental, social, and other effects

A decrease in the necessary emergency reserves (point 2) and the possibility to construct larger power plants (point 4) were also important in the creation of individual EPSs. The rest of the effects may be treated as specific ones that emerge when interconnecting EPSs. In concrete IPSs or NPSs, not all the enumerated effects but only a combination of them or even only one key effect can naturally be found.

Each effect has to be estimated in monetary terms (in rubles, dollars, etc.) in one way or another, and if their sum exceeds the cost of an intersystem electric tie (ISET), it is advisable to interconnect EPSs. As a rule, the economic assessment of the effects, in particular, the environmental and social effects, proves to be difficult enough. It requires special calculations based on appropriate mathematical models [24]

Note that the specific features of realizing different effects are important for a further study of the electricity markets. These features are stipulated in particular by the fact that many effects owing to the interconnection of EPSs are expressed in generation capacity saving, and are achieved by the construction of intersystem transmission lines. Some market models propose the separation of the spheres of electricity generation and transmission (and distribution) and the creation of independent

generation and network companies. In this case, the network companies will bear the costs and the generating companies will take advantage of the effect. Such an inconsistency (in comparison with single vertically integrated companies) will complicate the substantiation of the ISET efficiency, and hence the interconnection of EPSs.

Transmission (export) of cheap electricity from one EPS to another will shift the construction of new power plants, and, as a result, the former EPS will become surplus and the latter will be deficient. At the same time, it may influence electricity prices: they can fall in the receiving EPS and, on the contrary, rise (electricity demand will increase) in the transmitting (exporting) one. In different models of electricity market organization, these factors will show up in different ways. In the markets with regulated electricity prices, such an export may be mutually beneficial if the export price is set within the range of prices of EPSs to be interconnected. Then, the consumer price can be reduced in the exporting system owing to the export earnings, and in the receiving system owing to cheaper electricity received. In competitive markets with free prices, electricity export will cause a loss to consumers of the transmitting system because of an increase in electricity demand and prices.

The following two types of effects—a decrease in the required reserves and a coincident maximum load (in comparison with the sum of maximums for EPSs at their isolated operation)—directly lead to savings in generation capacities. They may be called "capacity" effects of interconnecting EPSs. These effects are very substantial for some countries. They are typical of the EPS as a whole at joint consideration (efficiency assessment) of the electricity generation and transmission spheres when construction of transmission lines decreases demand for generation capacities of EPSs to be interconnected and the total costs for EPS expansion.

The capacity effects of interconnecting EPSs are observed at any type of generation facilities and transmission lines. This fact is often underestimated when one speaks of the loss of the economies of scale in the power industry. The economies of scale imply not only the economic feasibility of increasing power plant sizes and transfer capability of transmission lines. It is typical of EPS as a system, i.e., the costs in the transmission sphere decrease the costs in the electricity generation sphere. It cannot disappear and will constantly manifest itself with an increase in EPS scales if it is not split into spheres and sets of companies.

The considered three types of effects also occur when EPSs of different countries are interconnected. The intensive formation of interstate electric power interconnections (ISEPIs) in almost all world regions proves it [24]
Hence, the economies of scale are inherent in EPSs both at the national and at the interstate levels.

The rest of the effects will not be commented upon. As a rule, their realization depends on the electricity market type to a lesser extent. They are described in greater detail in the mentioned papers, in particular in [24]

III. Properties of EPSs

Sets of physicotechnical, economic, social, and environmental properties are surely typical of EPSs. In our discussion below, consideration is given to those influencing market organization in the power industry in one way or another. Based on the variety of possible market types (models), the display of these properties will be noted in different (and sometimes in all) market models.

Here, the most general idea about models of electricity market organization seems to be expedient for further illustration of the impact of different properties of EPSs on them. Figure.1 presents four major models of the electricity market [28, 31]:

1. *Regulated natural monopoly* (absence of competition), which was already mentioned above. In the electric power industry, these are the so-called vertically integrated companies embracing all the spheres of electricity production, transportation, distribution, and sale. This market form has given rise to restructuring or reform discussed in the paper. The following market models are characterized by successive separation and differentiation of the indicated spheres with the formation of the corresponding generation, network, and sales

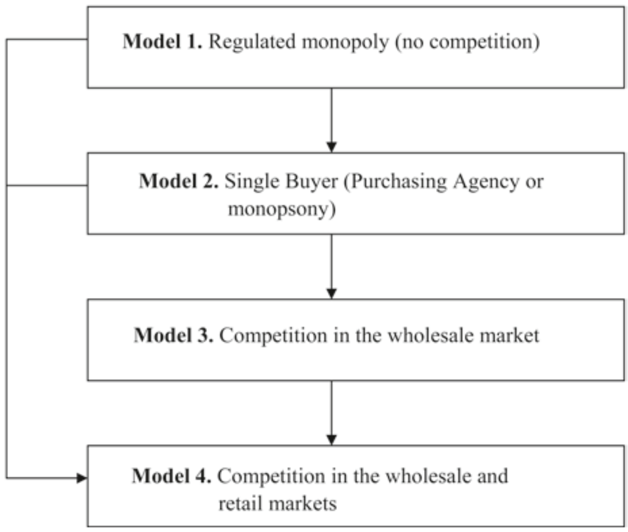


Fig. 1 Major modelsof the electricity market organization

companies.

2. *Single buyer* (Purchasing Agency, monopsony), when the generation sphere is divided into several separate (financially independent) power generation companies (PGCs) that start to compete with each other in electricity supply to the common Purchasing Agency. The other spheres remain vertically integrated into the agency and it is a monopolist with respect to consumers as before. The business of the Purchasing Agency, therefore, should be regulated by the State, including a price quotation of electricity purchased from producers and sold to consumers.

3. *Competition in the wholesale market*, when the electricity transportation sphere is separated, the spheres of electricity distribution and sale are split into territories and the wholesale market is organized. This leads to the creation of a transportation network company, territorial distribution-sales companies (DSCs), and specialized market structures. The wholesale market prices become free and the activity of DSCs and the retail prices are regulated as before.

4. *Competition in the wholesale and retail markets*, when the spheres of electricity distribution and sale are additionally divided with the formation of regulated distribution companies (by territory) and sets of independent sales companies. Retail electricity markets are organized with competition between sales companies (buying electricity in the wholesale market) and consumers. The retail prices are no longer regulated.

We should underline that all the enumerated models are market models, as often only the last two models are called markets. The first two models are markets with regulated prices—tariffs —and we will call them, for short, regulated markets, while the third and fourth models will be markets with free prices or competitive markets. For brevity's sake, these models will sometimes be referred to by the numbers under which they have been listed above (Model 1, Model 2, etc.).

The arrows on the left in Fig.1 show the transition at restructuring from the regulated monopolies at the regional level and the single-buyer model at the federal level to Model 4. The transition is stipulated by the Law of the RF "About electric power industry" [32]

Now we will address directly the properties of EPSs, which determine specific features of the electricity market.

The well-known properties and features of EPSs are:

- A special role of electricity in the economy and society; damage caused by the sudden interruption of electricity supply exceeds manifold the cost of undersupplied electricity, which requires special measures to support electricity supply reliability.
- The inability to store (accumulate) electricity in sufficiently large volumes.
- The necessity to balance electricity production and consumption at every moment.
- The inevitability of equipment failures, and hence the necessity of backup generation
- capacity and electric ties.

These properties undoubtedly influence and complicate market organization in the power industry to a varying extent in different market models. However, note some other features of EPSs that are also important in this context and are interrelated with the above properties in one way or another:

1. *Specialized electricity transport* (by wires). It excludes electricity delivery by general types of transport (railway, motor, water, air), which is possible for the production of the majority of other branches and renders a local character to EPSs. New electricity producers and consumers can emerge only by connecting them to EPS networks. This property leads to:

- The territorial limitedness of the electricity market: only consumers and producers directly connected to the EPS through electric ties with a sufficient transfer capability can participate in the market. In particular, there is no world electricity market or world electricity prices.
- Participation of only existing (operating) power plants in the market.
- Existence of the technological (physical) barrier to the entry of new producers into the market; to this end new power plants should be constructed and connected to EPSs. Thereby, one of the principal conditions for perfect competition — *free entry of new firms into the industry and free exit of existing firms from it* [30] — is not observed in the power industry.

It should be noted that a physical barrier for new power producers (NPPs) is especially important. It plays a decisive role in electricity markets in the short run (in the microeconomic sense). NPPs simply cannot appear in the market, because a new power plant should be designed, constructed, and connected to the EPS, which requires several years. In the shortrun electricity market, the operating producers are protected from the competition of NPPs and can raise prices. It is one of the basic reasons for electricity market imperfection and it cannot be eliminated (i.e., it is impossible to make the market perfect) by any organizational and methodological measures or rules.

2. *Daily, weekly, and seasonal load variations* that determine:

- The need to expand generation capacities according to an annual load peak (taking into account re-serves); in other periods of the year power plants will be underloaded and get lower revenues which may turn out to be insufficient to pay back investments.
- The economic viability to have different power plants (basic, peak, and semipeak) with various eco-nomic indices (specific capital investments and production costs).

- The need to optimize the structure of generation capacities (by type of power plants) and operating conditions of power plants for different periods of a year.

The presence of power plants of different types, in turn, leads to specific supply curves of producers and formation of marginal prices and producers' surplus [33] for more efficient power plants in the competitive wholesale market.

This feature of EPSs also caused the need for centralized dispatching control of the normal and emergency operation of the power system (which is foreseen in all market models) and also engendered the next property (or even paradox) in the electric power industry which is observed in no other industry.

3. *The need for optimization of the power system operation with regard to instantaneous (hourly) variable costs of power plants, while their total costs (and economic efficiency) are determined by integral operation results for the whole year with an account taken of fixed costs.* Load variations during a year cause changes in operating powers (load) of power plants, which should be optimized according to the criterion of the least hourly, daily, weekly, or seasonal variable (fuel) costs throughout the entire power system. While carrying out the optimization, we have to use hourly characteristics of power plants, which represent only variable costs.

Meanwhile, the real electricity value (and its price) is determined by the average total costs, including fixed costs of power plants as well. In the electric power industry, the average total costs can be determined only for the whole year. They will depend on an annual output of a power plant, its operation during a year (which determines annual variable costs), and annual fixed costs. This difference between hourly and annual costs influences essentially the organization of electricity markets and the process of price setting. In particular, the spot electricity markets organized in real time (with hourly or half-hourly intervals) are not real short-run markets considered in microeconomics, and their prices do not reflect the real value of electricity, which makes the spot markets inappropriate (see [21,22]). The real short-run electricity markets can only be the markets that cover the period of one or more years and are implemented through respective contracts.

4. *Great capital intensity, long periods of construction, and service of power plants and some transmission lines, which result in:*

• The impossibility of quickly eliminating shortage if it occurs for some reason. It will take several years to design and construct new power plants. Moreover, if power plants are constructed by private investors (Models 3 and 4), nearly 10 years more will be necessary to pay back the investments. Consequently, private investors should know the power system expansion conditions, including the prices in the wholesale market, 15–20 years in advance. These conditions are rather uncertain, which create a large risk for investors and make the construction of new power plants and elimination of shortage even more complicated.

• The need for prior planning and subsequent financing for the expansion of generation capacities in power systems to avoid shortage in the electricity market.

• Power plant service life (30–40 years) exceeding “reasonable” payback periods (10–15years), which will make private investors construct power plants (Models 2–4).

This feature of EPSs manifests itself to a greater extent under competitive markets (Models 3 and 4) when the criteria, incentives, and financing mechanism for construction of new power plants change dramatically as compared to the regulated monopoly and single-buyer market. These changes create problems of investing in the expansion of generation capacities, which are considered in [22]

Moreover, the competitive market concepts (including those in Russia) usually envisage no centralized planning of the generation capacity expansion. The generation capacities are supposed to expand based on "market signals." However, the experience of the countries that introduced the competitive electricity market and recent research have shown that the market does not generate these signals timely and special “non-market” measures are required to prevent power shortage.

5. *High level of mechanization, automation, and even robotization (at nuclear power plants) of electricity production, transportation, and distribution.* Normally, power plants and substations have only administrative, duty, and maintenance personnel. The number of personnel practically does not depend on the amount of actually generated and transmitted power. All process lines and units at power plants are designed based on their maximum (installed) capacity.

This feature of EPSs along with the said huge capital intensity of power plants leads to a high share of fixed costs in the total electricity production costs. At the same time, there are practically no variable costs at HPPs, and those at nuclear and thermal power plants are made up of fuel costs only. The characteristics (curves) of average costs of power plants, therefore, differ principally from the cost curves of “typical” firms considered in the theory of microeconomics. This makes the short-run competitive wholesale electricity market “nonstandard,” i.e., different from the markets in other industries. In particular, power plants (or power generation companies) will have to enter the market with their supply bids reflecting the total costs rather than the marginal ones.

6. *The interdependence of electricity production processes of different power plants in the power system.* All power plants operate to cover the total EPS load which changes daily and seasonally. Their operating conditions are optimized centrally, depending on the mix of generation capacities in the EPS.

This feature of the power system brings essential features in the electricity market:

• Power producers (sellers) do not enter the market with already finished products with known volumes and prices. Electricity is produced jointly and simultaneously by all producers. Volumes and costs of each producer will depend on centrally assigned operating conditions for different hours, days, and seasons. The most economically important annual volumes and costs of each producer will be determined only at the end of the year by integral results.

• Thus, the uncertainty exists in the characteristics of short-run costs of power producers. This uncertainty is not observed in the industries where firms (companies) produce commodities independently of one another. The uncertainty of power plant costs makes the electricity market very special. In the regulated markets (Models 1 and 2), this creates difficulties in establishing tariffs by the regulatory bodies. The regulation should envisage adjustment of tariffs if the actual output of power plants deviates considerably from the planned one (this is particularly necessary for HPPs, whose output depends on the random inflow of water). In the competitive markets (Models 3 and 4), the situation is even more complicated — the electricity producers in the market do not know exactly how much electricity they will produce throughout a year and what total costs they will bear. Naturally, they will overestimate the prices both in the spot market (if it exists) and in the long-term contracts with buyers.

7. *Facility-by-facility expansion of power systems*. The market in any power system expands through the construction of individual new power plants and transmission lines. This property reveals itself differently in different models of electricity market organization.

New power plants can be funded and constructed by:

- Vertically integrated companies (VICs) (Model 1)
- Power generation companies (PGCs) (Models 2–4)
- New independent power producers (IPPs) (Models 1–4)

Financing mechanisms for the construction of power plants will vary. The primary distinction is that under regulated markets (Models 1 and 2) the investments in new power plants are paid back at the expense of the total electricity output generated by VICs (or in EPSs), whereas under the competitive wholesale market (Models 3 and 4) the investments in some power plant should be paid back at the expense of the electricity generated by only that power plant alone.

Under the competitive market, each new power plant constructed by a private investor, along with operation costs, will have its investment components required to pay back the investments. Therefore, the price to be offered by the new electricity producer in the wholesale market will be higher than the price offered by the operating power plant of the same type. This creates an economic (price) entry barrier for new producers in addition to the physical barrier mentioned above, which makes the electricity market imperfect in the long run as well.

Additionally, the facility-by-facility expansion of generation capacities in EPSs influences the shape and sense of the long-run cost curves of the electricity generation sphere. Under competitive markets, the short-run costs of new power plants should be considered as long-run production costs of IPPs and PGCs.

Moreover, the transition to the competitive wholesale market changes the mechanism of financing the intersystem and interstate electric ties, which makes it difficult to substantiate their efficiency (see [24]).

8. *Economies of scale.* This was already considered earlier. This effect is to the greatest extent realized in the regulated monopoly (Model 1). In other models, it subsequently decreases (Model 2) or is even lost completely (Models 3 and 4) due to the splitting of one company into several separate companies. It should be emphasized once again that this effect is typical of the entire EPS (as a system) and not only of power plants in the electricity production sphere as it is sometimes interpreted (for example, in [28]).

The overall analysis of power system properties shows, on the one hand, the principal distinctions of the electricity market from the markets in the other industries and, on the other hand, its obvious imperfection.

The main distinctions are:

- The territorial limitedness of the electricity market (within the territory covered by the networks of a specific EPS).
- The need for dispatching control of normal and emergency conditions of the power system.
- The need for centralized design and planning of the power system expansion with account taken of the required capacity reserves.
- The impossibility of organizing “normal” electricity spot markets (for more details, see [22]).
- The non-typical and uncertain costs in the generation sphere of EPSs, which makes the competitive (unregulated) wholesale electricity market "nonstandard" in light of the theory of microeconomics.
- Obvious uniqueness of intersystem electric ties that connect different territorial electricity markets (for more details, see [22,24).

The electricity market imperfection is first of all conditioned by the technological (physical) barrier to new producers in the short run and by the price (economic) barrier to them in the long run. Whether or not the other conditions (requirements) of perfect competition are met is analyzed in the next Section. The imperfection of the electricity market reveals itself under any models of its organization. In Models 1 and 2, its monopolistic character is obvious and this leads to the necessity to regulate electricity prices (tariffs). In Models 3 and 4, the electricity producers, on the one hand, may form an oligopoly and, on the other hand, maintain "market power," thus having the chance to create a shortage and raise electricity prices through cessation or delay in construction of new power plants. This is also facilitated by the economic barrier mentioned above.

It should be noted that the electric power industry differs from other infrastructural industries, such as transport or telecommunications, in the production of commodities. It is the sphere of electricity generation that creates many of the foregoing EPS distinctions and makes the electricity market imperfect. This, in particular, relates to a nontypical character and uncertainty of costs in the sphere of EPS generation, to the impossibility of organizing electricity spot market, and to the existence of physical and price barriers to entry of new producers into the market. It is important to indicate this distinction, since in some countries (for example in the USA) one of the arguments for deregulation of the electric power industry was successful reforms in the air transport and telecommunications. This distinction of the power industry is analyzed in [3]

IV. Types of markets

Microeconomics [30, 33, 34] considers several types of markets:

1. *Markets with perfect (pure) competition*, which will be called shortly *perfect* markets. Such markets are considered most effective and are taken as a reference (sample), though in reality, they are quite rare (mostly in the agriculture). There are numerous conditions and requirements to be met in the market for the competition to be perfect: a great number of sellers and buyers, each being unable to affect the market price, their free access to the market and exit, etc.

2. *Absolute (pure) monopoly, when there is only one seller in the market.* This market is in absolute opposition to the previous one—an extreme case of an uncompetitive market. In particular, this monopoly can be observed in the power industry.

3. *Natural (regulated) monopoly,* which is effective if owing to economies of scale one firm in the industry can produce all the commodities at lower costs (and prices) than two or a larger number of firms. This situation, as was mentioned earlier, is characteristic of the power industry. In this case, the activity of the firm and prices of products should be regulated by the state (regional, municipal) bodies, for the firm not to abuse its monopoly position.

4. *Oligopoly*, when there are several sellers in the market and *entry of new sellers* into the market *is either complicated or impossible*. With "fair" competition, oligopoly can be very effective; however, there can be price manipulations—the use of market power by oligopolists, particularly under their collusion. The oligopoly situation is possible in the power industry if electricity prices are not regulated.

5. *Monopolistic competition* is typical of markets with partly interchangeable commodities (e.g., cars) which vary in quality and consumer properties. This kind of market is not characteristic of the power industry.

6. *Monopsony*, where there is only one buyer in the market. Here, unlike monopoly, it is the buyer, not the seller, who is in a privileged position (possesses market power). In microeconomics, this situation is considered mainly as applied to the manufacturer of some commodity, i.e., a firm which is the only buyer of a certain resource required for its production. Most often this resource appears to be labor. Meanwhile, in the power industry, the single-buyer market model is possible. This model implies that the sellers (many of them) will be producers of a ready product—electricity. However, the firm (power company) that performs the function of the "single buyer" (it is also called a "Purchasing Agency") will be a monopoly reseller for the final electricity consumers. Here, like in the case of natural monopoly, the state regulation of electricity prices is required.

7. *Oligopsony* is a kind of monopsony with several buyers in the market. This kind of market is seldom considered in the theory of microeconomics. The possibility of organizing such a market (regulated) in the power industry should not be excluded. For example, the electricity market that has emerged in the past years in Brazil (and is forming in Chile) represents, in general, the single-buyer market. There are several buyers there—distribution-sales territorial companies. Therefore, this market can be referred to as oligopsony as well.

There are also other types of markets (e.g., price discrimination) that are of no interest to the power industry.

All markets, except for the first one (with perfect competition), are imperfectly competitive or simply imperfect.

In the following sections, the first type of market will be considered in more detail to show the extent to which the electricity market does not meet the conditions and requirements for perfect competition.

V. Markets with perfect competition

Many conditions for perfect competition to emerge (to be provided) have been formulated. In [33], for example, the authors point out five such conditions:

1. *Many sellers and buyers participate in the market. The share of each of them is small with respect to the entire market, and therefore they cannot affect the price* (the price does not depend on supply or demand of individual market participants). In [23], this condition is interpreted as price-taking suppliers and buyers, i.e., those not trying to increase or decrease the price.
2. *Goods are homogeneous*, i.e., meeting the established standards. Therefore, the buyers do not care which seller to choose.
3. *Buyers are well informed about the sellers' price* — any seller increasing price loses its customers.

4. *Buyers and sellers act independently of each other*. They do not participate in price collusions. Each firm chooses the output volume that maximizes its profit on the assumption that it cannot affect the price. The buyers choose the volume of purchases acceptable for them at a given price.
5. *The firms can freely enter and exit the industry*. This condition is taken to guarantee that the firms existing in the industry cannot increase the price through agreement about output reduction since any price increase will attract new firms into the industry which will raise the supply volume.

In addition to the enumerated conditions, some papers name other conditions for perfect competition. For example, in [23] the author gives two more conditions:

6. *A good shape of the firm's short-run cost curve* ("well-behaved costs")—short-run marginal costs start rising while average costs stop shrinking after the firm reaches a certain (not very large) volume of production (i.e. the U-shaped forms of average variable and total cost curves are provided).
7. In the long ru*n, the characteristics of production costs of a firm should not create conditions for the natural monopoly.* This implies that the curve of long-run average costs (LAC) does not have a descending form, but on the contrary, an ascending one. In other words, there should be diseconomies of scale in the industry.

In [35], the author points out one more condition for the perfect competition that was determined by Nobel Laureates Gerard Debreu and Kenneth Arrow.

8. *Every market participant can buy insurance against any possible risk.* This condition can be considered rather important. Analysis of these eight conditions as applied to the electricity market shows that only condition 2 (a homogeneous or standardized product) is met in full measure. It should be noted, however, that some market organization models in the power industry foresee, along with the electricity market, the creation of markets for capacity, ancillary services, derivatives, etc., i.e., markets for several "products." This makes the market in the electric power industry imperfect and more complicated.

Conditions 5 and 7 are not met in the power industry at all. Free entry of producers into the industry is physically impossible because this will call for the construction of a power plant and its connection to an EPS. The physical barrier for new electricity producers makes the market imperfect in the short run when the installed capacities of power plants are fixed. Besides, in some models of the electricity market organization (Models 3 and 4), the economic entry barrier is created in the long run. The economies of scale that foster the formation of natural monopolies in the power industry, as was discussed earlier, are typical of the EPS. In this connection, it should be admitted that the electricity market is imperfect. This circumstance, by the way, is not disputed by anyone. However, the efforts to introduce competition are persistently made either in the hope to overcome this imperfection or for other reasons.

It is very difficult to meet condition 3 (buyers know well the prices of sellers) in the electric power industry (and not only in this industry). This condition is considered to be particularly important. It is discussed in all the papers devoted to perfect competition. In [23], the author points out adequate information available for all market participants, the author of [35] talks about perfect information, etc. In 2001, Joseph Stiglitz was awarded the Nobel prize in economics for his theory of "information asymmetry," i.e., the demonstration of the fact that information is not equally distributed among the market participants [35] Hence, we can consider that this condition for perfect competition is not met everywhere. The difficulties in providing adequate information in the electricity markets are considered in [4, 23], and in other papers.

It may seem that conditions 1 and 4 can be met since in large EPSs (and markets on their territory) there are many power plants and the number of power consumers is even larger. However, as a rule, power plants belong to a relatively small number of generating companies. In the competitive electricity markets with unregulated prices (Models 3 and 4), these companies retain market power to one extent or another and can even form an oligopoly. The examples of market power and its analysis are presented in many publications [9, 23, 36]

The short-run cost curves of power plants (condition 6) are studied in [21, 22] It is worth noting that the minimum point of average costs practically for all types of power plants is reached at their maximum annual output, i.e. the shape of these curves is not "good" (U-shaped).

Finally, to meet the last condition (insurance against any risk), it is necessary to create a special system of insurance.

Thus, we can state that the *electricity market is not a market with perfect competition*, and the organization of free competition (electricity price deregulation) can lead to undesirable consequences.

If competition in the market is imperfect, then without state regulation this market will be a kind of imperfect market: a monopoly or an oligopoly with dominating (market power) sellers and a monopsony or an oligopsony with dominating buyers. In the electric power industry that has the features of a natural monopoly, market power belongs to sellers (producers). As the experience in the early twentieth century shows, without regulation (under "spontaneous" market) this will lead to the formation of a monopoly. However, if the generation sphere is forcedly split into several independent power generation companies, then without regulation it will be an oligopoly.

VI. Conclusion

1. The analysis has shown that the special properties of electric power systems impede the fulfillment of several important conditions (requirements) of perfect competition in electricity markets, and exclude even the possibility of creating such conditions when organizing the markets. The conclusion can and should be drawn that electricity markets are imperfect in their nature, and no organizational and technical measures can make them perfect.

2. The main feature of the electric power industry is the use of power lines for electricity transmission, which territorially limits electricity markets, and creates difficulties in expanding the market (for new producers to enter the market) and the need to maintain a balance between electricity production and consumption at any given time, etc.

The main condition for the perfect competition that cannot be created in the power industry is free market entry and exit for the firms. In the short term, these are hampered by a physical (technological) barrier - it takes a new producer several years to enter the market (the power plant must be designed, built and connected to an EPS). In the long term, there appears an economic (price) barrier for new producers. They require market prices that exceed the costs of existing producers by the amount of the investment component necessary to pay off the investment in a new power plant.

3. In imperfect markets, government regulation of electricity prices is required. The absence of the regulation can lead to rising prices, power shortages, etc. There were such troubles at the beginning of the century in various countries of the world (starting with the California crisis in the USA) but their analysis goes beyond the scope of this paper. Similarly, the consequences of the transition to the competitive electricity market in Russia require special consideration.

References

[1] On Restructuring the Electric Power Industry in the Russian Federation/Decree of the Government of the Russian Federation of July 11, No. 526, 2001, (in Russian).

[2] Sioshansi F., "Electricity Market Reform: What Have We Learned, What Have We Gained", *Electr J,* vol. 19, no. 9:70–83, 2006.

[3] Coppens F., Vivet D., "Liberalization of Network Industries: Is Electricity an Exception to the Rule?" National Bank of Belgium. Working Paper no. 59, September, 2004, http://www.nbb.be

[4] Woo C., Lloyd D, Tishler A., "Electricity Market Reform Failures: UK, Norway, Alberta, and California". Energy Policy, vol. 31:1103–1115, 2003.

[5] Banks F., "A Simple Economic Analysis of Electricity Deregulation Failure", *OPEC Rev.*, June:169–181., 2002.

[6] Joskow P., "The Difficult Transition to Competitive Electricity Market in the U.S," Proceeding of the Conference “Electricity Deregulation: Where From Here?” *Texas A&M University*.

[7] Apt J., "Competition Has Not Lowered US Industrial Electricity Prices," Carnegie Mellon Electricity Industry Center Working Paper CEIC-05-01, 2005. http://www.cmu.Edu/electricity

[8] Rudnick H., Barroso L, Skerk C, Blanko A., "South American Reform Lessons,". *IEEE Power Energy Mag*, vol. 3, no. 4:49–59, 2005.

[9] Woo C., King M, Tishler A, Chow L., "Cost of Electricity Deregulation," *Energy*, vol. 31:747–768, 2006.

[10] Tishler A., Woo C., "Likely Failure of Electricity Deregulation: Explanation with Application to Israel," *Energy*, vol. 31:845–856, 2006.

[11] Electricity Rates Remain Highest in the Deregulated States. *Bus Dev Transm Distribution World*, vol. 58, no. 8, 2006.

[12] McCullough R, Howard B, Deen M The High Cost of Restructuring. Public Util Fortnightly, February:54–58, 2008, http://www:fortnightly.com

[13] Belyaev L., "A Systems Approach to Development Planning of the Fuel Power Industry of a Planned Economy Country. RR-76-6," International Institute for Applied Systems Analysis, Laxenburg, Austria, 1976.

[14] Belyaev L, Voitsekhovskaya G, Saveliev V et al System Approach to the Management of Power Industry Development. Nauka, Novosibirsk, 1980, (in Russian).

[15] Belyaev L., Electricity Markets: Comparing Competitive and Single Buyer Markets. IEEE Power Energy Mag, vol. 5, no. 3:16, 18, 20, 22, 24–26, 2007, (in Russian).

[16] Belyaev L (2005) The Need for a Regulation of the Generation Capacity Development in a Competitive Electricity Market. Proceedings of Int Conf “*2005 IEEE St Peter Power Tech*,” St Petersburg, Russia, 2005.

[17] Belyaev L, Podkovalnikov S., "Electricity Market: Problems in Expansion of Generation Capacities," *Nauka*, Novosibirsk, 2004, (in Russian).

[18] Belyaev L., "Marginal Prices in the Wholesale Electricity Market and “Producer’s Surplus,” *Energiya: ekonom, tekhnika, ekologia*, no. 4:2–9, 2004, (in Russian)

[19] Belyaev L., "Does Russia Need a Competitive Market in Electric Power Industry?" *Energiya: ekonom, tekhnika, ekologia*, no. 4:2–7, 2007, (in Russian)

[20] Belyaev L, Khudyakov V., "Worldwide Experience in Electricity Market Reform," *Northeast Asia Energy*

Forum, vol. 5, no. 4:32–53, 2008,. http://www.neasiaenergy.net

[21] Belyaev L., Problems of Electricity Market. Nauka, Novosibirsk, 2009, (in Russian).

[22] Belyaev L., "Electricity Market Reforms: Economics and Policy Challenges," *Springer*, New York, 2011.

[23] Stoft S., "Power Systems Economics: Designing Markets for Electricity," *John Wiley & Sons, Inc*., New York, 2011.

[24] Belyaev L, Podkovalnikov S, Saveliev V, Chudinova LYu, "Efficiency of Interstate Electric Ties," *Nauka*, Novosibirsk, 2008, (in Russian).

[25]Volkenau I., Zeiliger A, Khabachev L., "Economics of Creating Electric Power Systems," *Energiya*, Moscow, 1981, (in Russian).

[26] Rokotyan S.S., Shapiro IM (eds) "Reference Book on Designing Electric Power Systems", 3rd rev. and enl. ed. *Energoatomizdat*, Moscow, 1985, (in Russian).

[27] Rozanov M., "Reliability of Electric Power Systems," *Energiya*, Moscow, 1974, (in Russian).

[28] Hunt S., Shuttleworth G., "Competition and Choice in Electricity," *John Wiley & Sons, Ltd., Chichester*, England, 1996.

[29] Hingorany N., Gyugui L., "Understanding FACTS: Concepts and Technology of Flexible AC Transmission System," *IEEE Press, Piscataway*, NJA€, 1999.

[30] McConnel C., Brue S., "Economics: Principles, Problems, and Policies," 14th edition, McGraw-Hill, Toronto, 1999.

[31] Kirschen D., Strbac G., Fundamentals of Power System Economics. John Wiley & Sons, Ltd., Chichester, England, 2004.

[32] On the Electric Power Industry, Federal Law of the Russian Federation, March 26, no. 35-f3, 2003, (in Russian).

[33] Fischer S., Dornbusch R., Schmalensee R., Economics, 2nd ed. McGraw-Hill, New York, 1988.

[34] Haiman D., Modern Microeconomics: Analysis and Applications, vol. 2. Finansy i statistika, Moscow, 1992, (in Russian).

[35] Stiglitz J., "The Roaring Nineties. Seeds of Destruction, *W.W. Norton & Company*, New York, 2003.

[36] Miisgenst F., "Quantifying Market Power in the German Wholesale Electricity Market Using a Dynamic Multi-Regional Dispatch Model," *J Ind Econ, vol*. 54,.no. 4, pp. 471–498, 2006.

Control Strategies For Maximizing Renewable Energy Utilization In Power Systems

Michael Negnevitsky*, Evgenii Semshchikov, James Hamilton, Xiaolin Wang , Ekaterina Bayborodina

School of Engineering, University of Tasmania, Hobart, Australia

***Abstract* — Environmental and economic challenges lead to the rapid growth of the renewable energy (RE) market in many countries. At a high level of RE sources (i.e. wind and solar) penetration, power systems face technical difficulties associated with the critical frequency stability and insufficient power reserves. The problem becomes particularly acute at penetration levels higher than 50 %, when conventional generation units are forced to operate at partial load, potentially resulting in premature equipment wear. Energy storage and demand-side management may offer solutions in the future, however, at the current stage, they incorporate substantial capital investment and complicate control system. This paper suggests a control strategy for maximum RE penetration, adopting a low load diesel application integrated with a small-capacity battery energy storage system. The strategy results in improved renewable energy utilization without overcomplicating the control architecture. Initially, a mathematical model is developed, then it is validated based on an isolated power system – a power system where penetration of RE already exceeds 50 % annually. Optimized control strategies are shown to deliver a 20 % increase in renewable energy penetration in comparison to conventional ones.**

***Index Terms* — Battery energy storage system, low load diesel, power system control, renewable energy.**

I. Introduction

The electrical energy generated by fossil fuel power plants contributes to the growth of greenhouse gas emissions, which, according to the Paris agreement, must be significantly decreased in the future [1]. The authorities around the world have set targets to increase the application of renewable energy sources (RES) for electricity generation. The most abundant RESs – wind and solar – are proven to be cost-effective and implemented in many existing power systems (e.g. Denmark, Ireland, and Germany) [2]. Unfortunately, these sources are stochastic and intermittent in nature, which requires more flexible power systems that, in addition to variable demand, have to deal with a variable supply [3]. With an appropriate level of the system flexibility, the balance between demand and supply can be provided at each time point. Therefore, while increasing RES penetration it is essential to take measures to improve system flexibility and to prevent future stability and reliability issues.

Demand-side management (DSM) is used in electric power systems to increase renewable energy utilization additionally improving system flexibility [3]. Such an approach is cost-efficient, however, it involves a range of different information and communications technologies (ICT), sophisticated control hierarchy and requires highly qualified personnel, which complicates the control system and increases the chances for failure.

Energy storage technology is another candidate capable to tackle the problems of RES integration and system flexibility. Energy storage systems (ESS) are generally used for energy shifting, load peak shaving, power quality regulation and provision of spinning reserve. Pumped hydroelectric power plants [4], hydrogen storage [5] and compressed air energy storage (CAES) [6] can be used in applications when the load changes slowly. Battery ESSs [7], supercapacitors [8] and superconducting magnetic energy storage (SMES) [9] respond fast and provide power quality support. The system inertia response can be improved by using flywheels [10] or implementing synthetic inertia of the battery ESS [11]. Storage is a very promising technology and is currently tested in many pilot projects, however, at this stage, it is still expensive.

Another way to sustainable RES penetration is to operate these sources flexibly – using droop controllers implemented at the power converter level [12]. De-loading of wind turbines [13] and optimized algorithms of PV

* Corresponding author.
E-mail: michael.Negnevitsky@utas.edu.au

http://dx.doi.org/10.25729/esr.2019.02.0006
Received September 02, 2019. Revised September 25
Accepted October 10, 2019. Available online October 31, 2019.

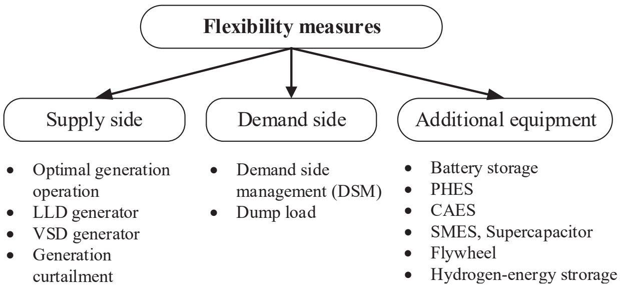


Fig. 1. Energy system flexibility measures

maximum power point tracking (MPPT) [14] are shown to improve primary frequency response. In spite of higher system flexibility, these methods result in lower RES utilization and complicated control architecture.

High RES penetration (> 60 % p.a.) has been already achieved in some Australian isolated power systems (IPS). These systems piloted technologies such as the advanced lead-acid battery, DMS, optimal generation sizing and low load diesel (LLD) generation [15]. From the experience gained through the years of the IPSs operation, one can conclude that at the current progress conventional fossil fuel generation cannot be eliminated from a power system irrespective of its size or location. With the minimization of fossil fuel energy as a target, high RES penetration can be achieved without leading to power quality or stability issues. This approach can be maximized through the use of LLD technology in combination with a low capacity battery ESS adopted in this paper. LLD allows the removal of diesel load limits (< 40% capacity constraint) resulting in greater system flexibility at high levels of RES penetration [16].

The paper is structured as follows, Section II presents different ways of RES integration. The control system architecture is outlined in Section II. The modeling methodology is given in Section IV. Case studies, shown in Section V, are based on the data from existing IPS. Section VI concludes the paper.

II. Integration of Renewable Energy

In traditional power systems, flexibility can be achieved by a portfolio of different kinds of power plants. Energy system flexibility can be roughly defined as an ability of a system to operate properly, ensuring the balance between generation and consumption, under uncertainty and variability in both power demand and power supply.

With the introduction of stochastic and intermittent electricity sources (i.e. wind and solar), the need for additional energy system flexibility increases dramatically. It can be achieved by introducing measures on the supply side, on the demand side or through placement of additional equipment such as storage technologies (Fig.1).

Due to physical constraints, a conventional generation unit operates within a specified range. By optimizing the operation of generation units, the lower load limit can be achieved. Low load and variable speed diesel engines are promising technologies capable to operate in a range from 0 to 100% loading. As a result, greater renewable energy utilization can be reached as shown in Fig. 2 (b) compared to conventional generation Fig. 2 (a). With the excess of renewable generation in the system, part of it has to be curtailed.

Demand-side management (DSM) can shift the utilization of renewable energy by reducing, increasing or re-scheduling energy demand as shown in Fig.2 (c). It can provide flexibility in terms of both power (with fast response) and energy.

The same shift in renewable energy can be performed by using storage technology. The surplus renewable energy in the grid is accumulated during favorable weather conditions and then released during the peak demand.

III. Power System Control

With the high number of non-dispatchable renewable energy resources, the flexibility of the system can be provided by the optimally designed control system. In this context, ancillary services are of particular importance. They are used to prevent system stability and reliability issues. Depending on the involved technology (i.e. its power, energy, response capabilities), different ancillary services can be provided. Three-level control hierarchy, involving primary, secondary and tertiary control, is adopted in many conventional power systems. The timing of control ranges and associated ancillary services are presented in Fig. 3.

$$\Delta P_{dr} = K_{dr}(f - f_{ref}), \tag{1}$$

where K_{dr} is the inverse of speed droop R:

$$R = \frac{\Delta f}{\Delta P_{dr}} = -\frac{1}{K_{dr}}. \tag{2}$$

Frequency offset left after the primary response can be corrected by the secondary controller (or AGC – automatic generator control). It restores the primary control reserve

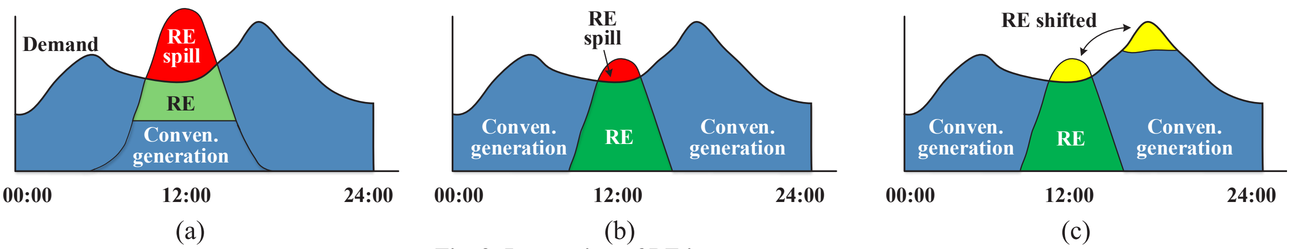


Fig. 2. Integration of RE in power systems.

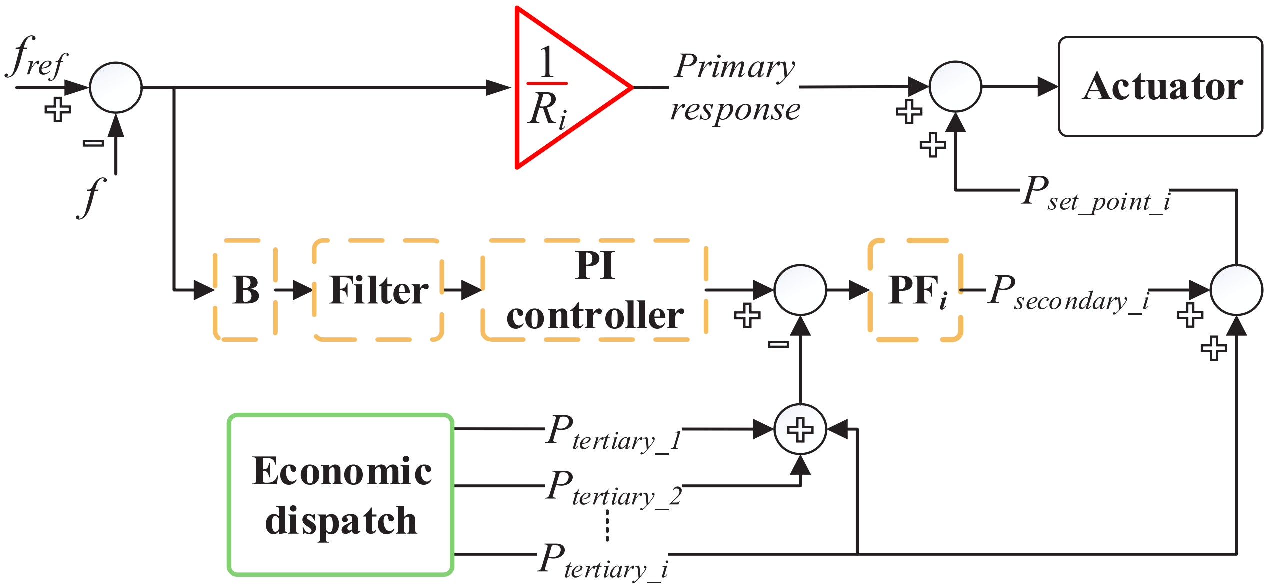


Fig. 4. A general model of a governor for a controlled element.

and brings the system to its nominal operating condition. Secondary control is involved in a centralized dispatching scheme and updates operation setpoints of responsible units every 0.1 to 1 second. Secondary control is mostly implemented as a proportional-integral (PI) controller where the priority of each generating unit is determined by a participation factor. The coefficient of the PI controller and participation factor are set to represent the physical constraints of a participating unit (costs, ramp and dispatch limits). The following equation implements control action of both primary and secondary control:

$$\Delta P_d = -B \cdot G - \frac{1}{T} \int G dt, \tag{3}$$

where P_d is the correction signal of the central regulator, $G = (f - f_{ref})$ – frequency deviation, B is a proportional term.

Tertiary control is used to restore the secondary control reserve and dispatch generation units according to the desired objective function. This function can include economic dispatch, priority dispatch, etc. Tertiary control is an automatic or manual change in operation points of all dispatchable technologies, which are updated every 1-5 minutes.

The general model of a governor at a power plant involved in all three control schemes is shown in Fig 4. It is worth noting that primary response is based on the measurements obtained locally, and secondary and tertiary controllers send updated operational setpoints via a communication network.

IV. Power system equipment modeling

A. Conventional generation

The conventional generation unit is comprised of a synchronous generator (SG) connected to the prime mover (e.g. hydraulic turbine, steam turbine, diesel engine, etc.) controlled by the governing system (Fig.5).

The standard or seventh order model of an SG is shown in Fig. 6, in which ω_b is the base electrical angular velocity, p is a short-hand notation for the operator d/dt, T_e and T_m are electrical and mechanical torques, H is the rotor inertia, ψ_{mq} and ψ_{md} are mutual flux linkages in q-axis and d-axis. Subscripts fd, $kq1$ and $kq2$ denote one field and two damping windings.

Matrix K_s^r represents a linear transformation from stationary to rotating reference system.

A direct voltage applied to the field winding, e_{xfd} , is adjusted by the excitation system to keep the terminal voltage at its rated value. This paper adopts the IEEE AC1A excitation system.

B. Photovoltaic solar generation

A photovoltaic (PV) unit converts solar energy into DC. It is usually connected to the AC grid via DC/AC power converter as shown in Fig. 8.

PV array is a model corresponding to the single diode model that takes irradiance, ambient temperature and network voltage as input data and outputs the value of current flowing to the grid (Fig.7).

The following equation is used in this paper to express PV current:

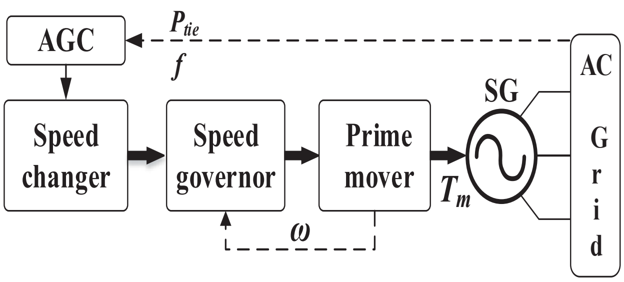


Fig. 5. Conventional generation unit.

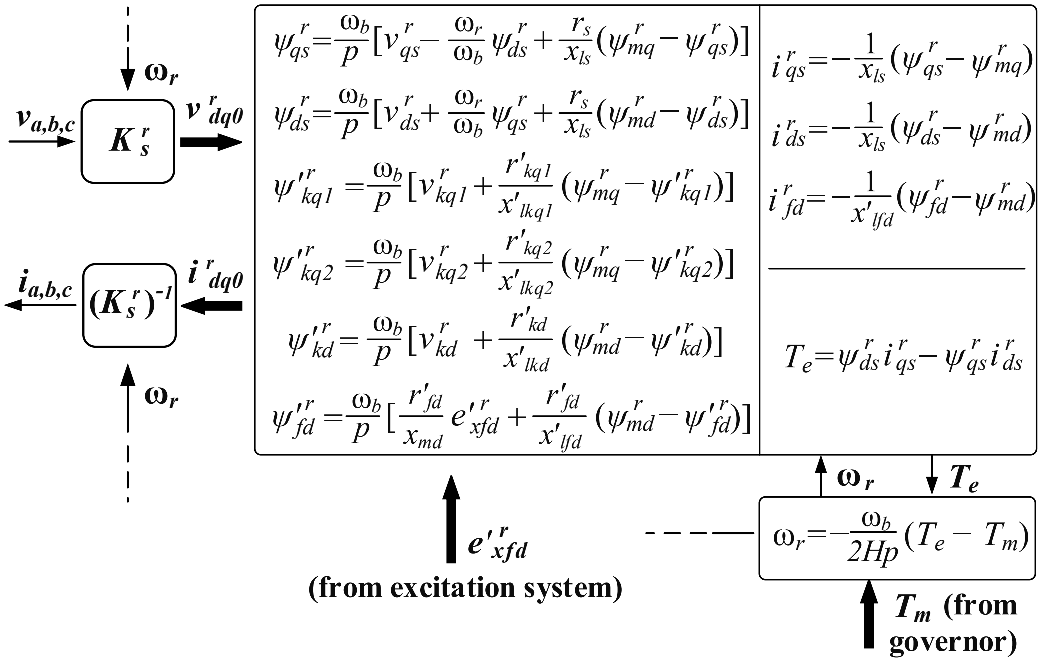


Fig.6. Synchronous generator standard model.

$$I_{pv} = N_p \left(I_{ph} - I_0 \left[\exp\left(\frac{\frac{V_{pv}}{N_s} + \frac{N_C}{N_p} I_{pv} R_s}{a N_C V_{th}} \right) - 1 \right] - \frac{\frac{V_{pv}}{N_s} + \frac{N_C}{N_p} I_{pv} R_s}{N_C R_p} \right) \quad (1)$$

where I_{pv} and V_{pv} are the current and voltage of the PV array, I_{ph} is the light generated current of the cell, I_0 is diode saturation current, V_{th} is thermal voltage, R_s and R_p are series and parallel resistances, a is diode ideality factor, N_c is the number of cells in module, N_p and N_s are the quantities of PV modules in parallel and series.

C. Wind energy generation

Wind energy is harnessed by wind turbines, which convert it into electrical power. One of the most applied designs is the combination of a wind turbine, gearbox, doubly-fed induction generator (DFIG), harmonic filters, and a back-to-back PWM partial power converter. A block diagram of such a system is presented in Fig. 9.

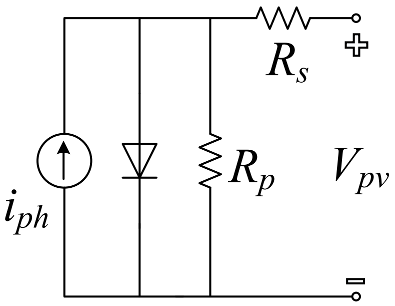


Fig. 7. PV equivalent circuit.

DFIG is modeled as a wound rotor induction machine with bidirectional power flow in the rotor circuit. The stator circuit is connected directly to the AC grid and supply unidirectional power to the grid. Like the SG, DFIG is presented by the set of differential equations (Fig. 10).

Wind turbine model is represented by the following equation:

$$P_m = c_p(\lambda, \beta)\frac{\rho A}{2} v_{wind}^3 \quad (2)$$

where P_m is turbine mechanical power, c_p is performance coefficient of the turbine, ρ is air density, A is turbine swept area, the v_{wind} is wind speed, λ,β are tip speed ratio and blade pitch angle.

D. Battery storage system

Battery energy storage system (BESS) is used in the system to extend its flexibility. For higher reliability, the battery can be connected to the grid via a back-to-back DC/AC converter. (Fig. 11.) The battery dynamic model was described and experimentally validated by the authors [17].

The state of charge (SOC) of the battery energy storage system can be expressed in the discrete-time domain as follows:

$$SOC_{(j+1)} = (1-d)SOC_{(j)} - t_s \frac{\eta_{bat}}{E_{nom}} P_{bat(j)}$$

where d is the self-discharging rate; η_{bat} is the charging or discharging efficiency; E_{nom} is the battery nominal energy; $P_{bat(j)}$ is the power flowing from or to the battery at time t_s.

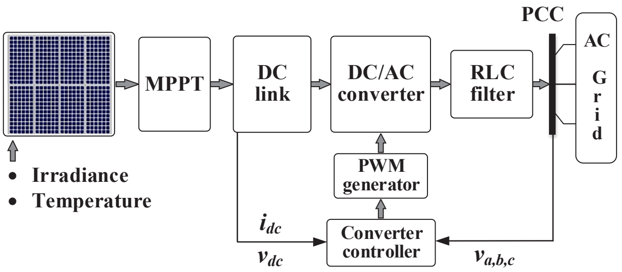


Fig. 8. Grid-connected PV unit.

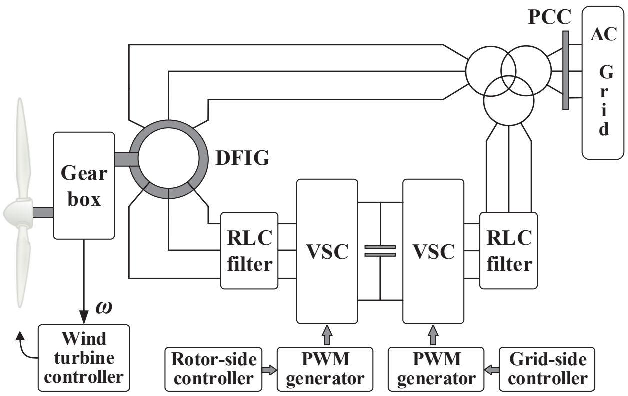


Fig. 9. Wind energy conversion system.

E. Dump load

Demand-side flexibility measures include the controlled resistive load. It transforms the electric energy into waste heat when combined generated energy exceeds the demand. In a way, the inability to control renewable energy is substituted by controllable demand.

Dump load consists of several three-phase resistors connected in series with power electronic switches. The total overall resistance follows a binary progression and can be adjusted accordingly in a step progression (P_{step}).

F. Low load diesel generator

Low Load Diesel (LLD) allows an engine's full capacity to be utilized by removing the engine's low load limit, 30~40% of the rated capacity as set within the conventional diesel engine.

The lower the diesel generators can run, the larger load can be allocated to RE technologies. LLD requires no new hardware, adopting the existing diesel assets, without modification to the mechanical or electrical architecture. The LLD model is shown in Fig. 13. The value τ1 is the engine delay, which represents combustion delay, the time between the actuator fuel-injection and the production of mechanical torque [18, 19], the power-stroke delay [20], and the ignition delay. In an LLD configuration, the ignition delay is longer compared to a conventional asset due to the lower operating load. With the Watson [21, 22] formulation used to predict the ignition delay, the value for the LLD is 0.3~0.5 ms higher than that for the conventional.

The model of an LLD generator, comprised of a governor, engine and generator is presented in Fig. 13.

Fuel costs for the diesel generator are calculated for a chosen time and expressed by the quadratic cost function as follows:

$$F_g = a_g + b_g P_g + c_g P_g^2$$

where a, b, c are the parameters related to diesel generator fuel consumption; C is the price of one liter of diesel fuel; P_g is the power generated by the diesel unit.

V. Case studies

Many papers suggest that future electric power system will be mainly driven by RES. However, current large-scale interconnected power systems are still dependent on fossil fuel. High RES penetration is now achieved in many isolated power systems, where small network size and high generation costs justify the means. For IPSs, a single RES integration project results in significant penetration, making them particularly relevant for validating and testing new methods and technologies.

This paper presents a King island IPS as a test case for the developed methodology. The IPS has an average load of 1.5 MW and annual RES penetration around 60%. The system consists of a portfolio of diesel generators, wind turbines, solar arrays, a dump load and a battery energy

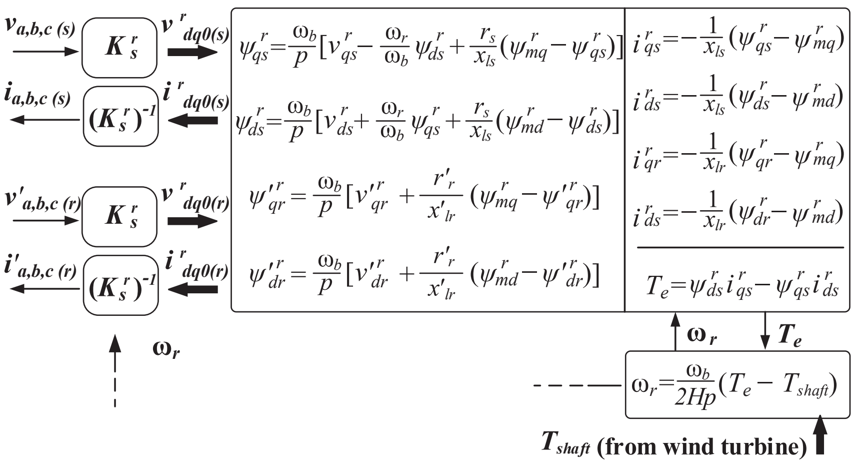


Fig. 10. Doubly-fed induction generator standard model

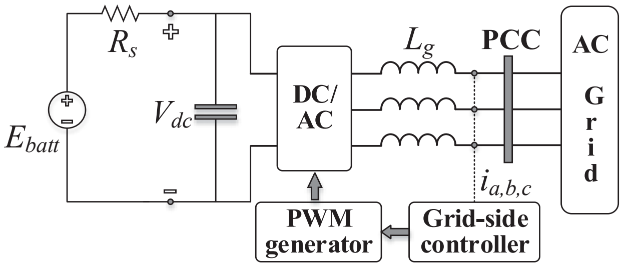


Fig. 11. Doubly-fed induction generator standard model

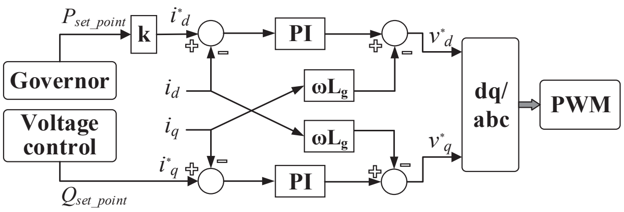


Fig. 12. VOC with a decoupled controller.

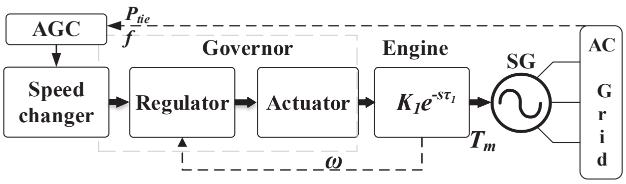


Fig. 13. LLD model.

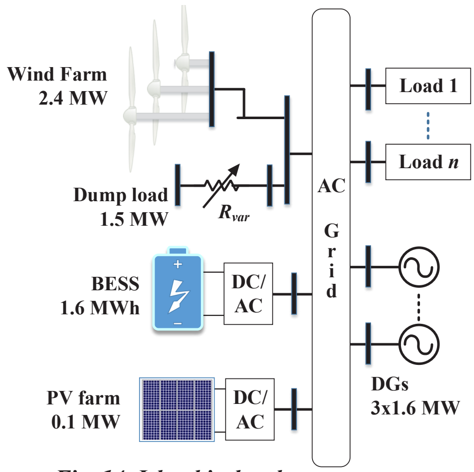


Fig. 14. Island isolated power system.

Table 1. Coefficients for the cost function

Source	*a*	*b*	*c*
Diesel	30	$4e^{-8}$	$6e^{-11}$

Table 2. priority dispatch for re maximization

Element	Priority given excess of generation
Diesel generator	1
Battery	2
Dump load	3

storage system (Fig. 14).

Four RES integration case studies are presented, case study 1 investigates minimal diesel fuel consumption with low capacity battery ESS, while case study 2 considers a high capacity ESS for greater system flexibility allowing prolonged zero-diesel operation (ZDO). Case study 3 looks into the minimization of operating costs by adopting LLD technology, while case study 4 maximizes RES utilization. Table 1 presents a one-year comparison of all four control strategies.

Diesel generator cost function, expressed by the quadratic equation with the coefficient shown in Table 1, represents experimental data obtained in our studies.

The IPS control center sends control action to dispatchable generation and consumption units. In this case, diesel generator, battery ESS and dump load can be adjusted to achieve the desired operational point. When the generation exceeds consumption, the control center operates following the priority dispatch presented in Table 2. Reverse priority is used for the negative system energy mismatch.

A. Control strategy involving low capacity BESS

Case study 1 presents the operation of the system with low capacity BESS. The battery is used to shift renewable energy from periods of favorable weather conditions (from 03:00 to 6:00) to period when only diesel generation is available to cover the load (from 06:00 next day), shown in Fig. 15.

The battery is used to cover any mismatch in the system up until it reaches its critical SOC. When the battery is

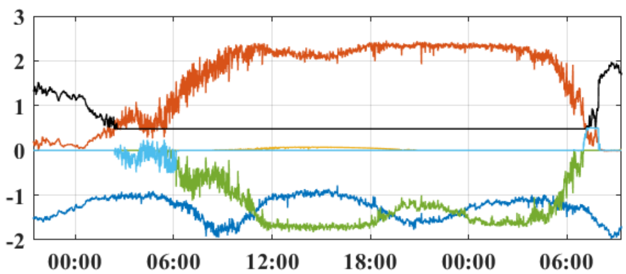


Fig. 15. Case study 1. IPS control strategy involving low capacity BESS. 1 (dark blue line) – power demand, 2 (red line) – wind power, 3 (orange line) – PV power, 4 (black line) – diesel power, 5 (green line) – dump load power, 6(light blue line) – battery power.

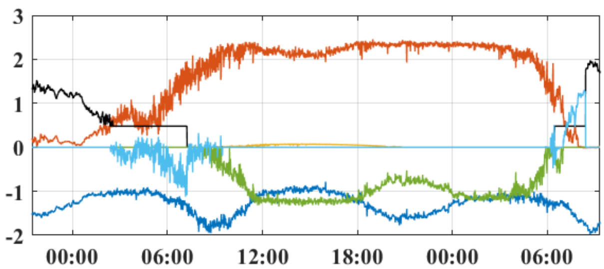


Fig. 16. Case study 2. IPS control strategy involving high capacity BESS. 1 (dark blue line) – power demand, 2 (red line) – wind power, 3 (orange line) – PV power, 4 (black line) – diesel power, 5 (green line) – dump load power, 6 (light blue line) – battery power.

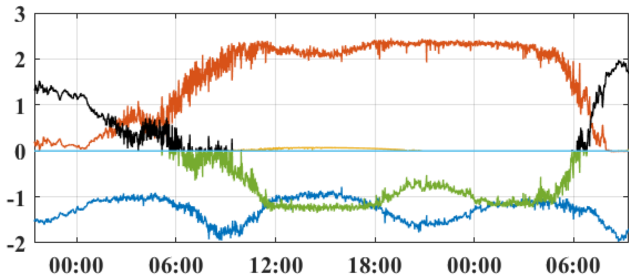


Fig. 17. Case study 3. IPS control strategy involving LLD. 1 (dark blue line) – power demand, 2 (red line) – wind power, 3 (orange line) – PV power, 4 (black line) – diesel power, 5 (green line) – dump load power, 6 (light blue line) – battery power.

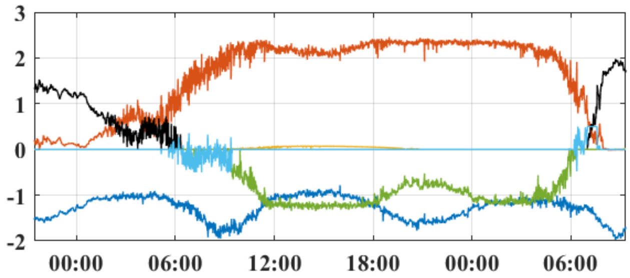


Fig. 18. Case study 4. IPS control strategy involving BESS and LLD. 1 (dark blue line) – power demand, 2 (red line) – wind power, 3 (orange line) – PV power, 4 (black line) – diesel power, 5 (green line) – dump load power, 6 (light blue line) – battery power.

Table 3. Control strategy analysis over one day for case 1.

Allocated energy	*Spilled RE*	*Operating costs*
48.2% Diesel energy; 51.8% RE	33.1MWh	Diesel: 138$/MWh

Table 4. control strategy analysis over one day for case 2.

Allocated energy	*Spilled RE*	*Operating costs*
22.4% Diesel energy; 77.6% RE	21.1MWh	Diesel: 91.2 $/MWh

Table 5. Control strategy analysis over one day for case 3.

Allocated energy	*Spilled RE*	*Operating cost*
22.6% Diesel energy; 77.4% RE	21.3MWh	Diesel: 94 $/MWh

Table 6. Control strategy analysis over one day for case 4.

Allocated energy	*Spilled RE*	*Operational cost*
21.5% Diesel energy; 78.5% RE	20.7 MWh	Diesel: 91.6 $/MWh

fully charged, the dump load performs power regulation (from 6:00 to 6:00 next day). It is worthwhile to note that due to insufficient security margin, the conventional diesel generator cannot be disconnected during the considered interval, operating at its low limit (30% of nominal power).

This strategy maximizes renewable energy penetration capturing some energy that would otherwise be wasted by the controlled resistive load.

Table III presents an analysis of the proposed control strategy, where the first column shows the penetration of RES during the considered day, the second column indicates the value of spilled RE. The last column presents the operating costs of a diesel generator. Although the significant RE utilization can be observed (52%), the diesel operating costs are high.

B. Control strategy involving high capacity BESS

According to case study 1, the higher the battery capacity the higher RES penetration can be achieved. An advanced lead-acid battery of 1.6 MWh can supply the entire island with power for up to 45 minutes. Besides, such a battery can improve system flexibility as it operates within the range from -1MW to 1MW. This, in turn, increases the security margin, which allows the ZDO from 08:00 to 8:00, as shown in Fig. 16.

Low-load diesel operating costs and high RES penetration are achieved as shown in Table IV. Although it goes beyond the scope of this paper, it has to be mentioned that with this approach high capital and operating costs associated with battery are inevitable.

C. Control strategy involving LLD

Another approach to high renewable penetration is to increase the flexibility of a generation unit, to allow its operation below 30 %. This results in high RES utilization with lower diesel fuel consumption.

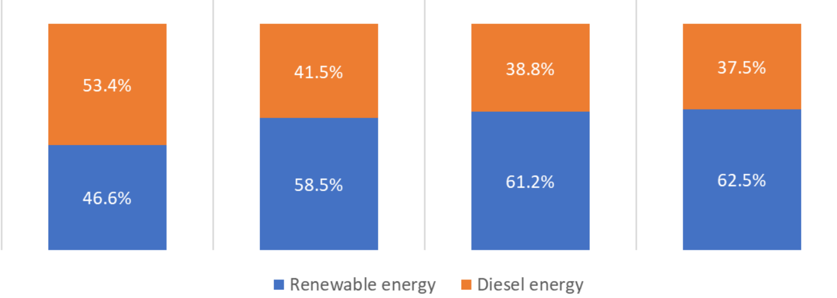
As shown in Fig17, the low-load diesel generator is capable to operate from 04:00 to 06:00 on its own releasing the need to trigger either dump load or BESS.

As shown in Table 5, LLD technology adopted by the proposed strategy enables similar RE penetration (77.4% compared to 77.6%) without the need for a storage system.

D. Control strategy involving BESS and LLD

For maximum RES utilization, LLD technology can

Table 7. One-year comparison of control strategies.



	Conventional diesel (0.6 MWh battery)	Conventional diesel (1.6 MWh battery)	LLD (no battery)	LLD (0.6 MWh battery)
RE penetration (%)	46.6	58.5	61.2	62.5
Wasted RE (GWh)	3.44	2.06	1.81	1.63
The operating costs of diesel ($/MWh)	154	131.68	128.3	125.8

be extended by the inexpensive small capacity BESS. As shown in Fig. 18 and Table VI, it extends ZDO at the time interval from 06:00 to 08:00 and allows the shift of RE.

Table 7 demonstrates an annual analysis of the proposed control strategies.

VI Conclusion

The control strategies for high renewable penetration in the electric power system were discussed. In addition to greater RES utilization, these strategies were aimed at improving the system flexibility and reliability. The proposed strategies were applied to the case of an isolated power system, comprised of diesel, wind, and PV solar generation. The system was also equipped with a controlled resistive load and a battery energy storage system or low-load diesel generator. It is shown that great RES utilization (around 58,5 % p.a.) can be achieved by using high capacity BESS, which results in low diesel consumption (131.68$/MWh). However, such technology is still young and involves high capital investments. A similar level of penetration and fuel saving was achieved by using LLD technology. For maximum RES penetration (62.5% p.a.), LLD is integrated with low-capacity inexpensive BESS, which additionally results in lower diesel fuel costs (125 $/MWh).

References

[1] A. Bloess, W.-P. Schill, and A. Zerrahn, "Power-to-heat for renewable energy integration: A review of technologies, modeling approaches, and flexibility potentials," *Applied Energy*, vol. 212, pp. 1611-1626, 2018/02/15/ 2018.

[2] W. Europe, "Wind in power: 2016 European statistics," Bruksela: *Wind Europe*, 2017.

[3] P. D. Lund, J. Lindgren, J. Mikkola, and J. Salpakari, "Review of energy system flexibility measures to enable high levels of variable renewable electricity," *Renewable and Sustainable Energy Reviews*, vol. 45, pp. 785-807, 2015/05/01/ 2015.

[4] J. P. Deane, B. P. Ó Gallachóir, and E. J. McKeogh, "Techno-economic review of existing and new pumped hydro energy storage plant," *Renewable and Sustainable Energy Reviews*, vol. 14, no. 4, pp. 1293-1302, 2010/05/01/ 2010.

[5] F. Gutiérrez-Martín, D. Confente, and I. Guerra, "Management of variable electricity loads in wind – Hydrogen systems: The case of a Spanish wind farm," *International Journal of Hydrogen Energy*, vol. 35, no. 14, pp. 7329-7336, 2010/07/01/ 2010.

[6] S. Sundararagavan and E. Baker, "Evaluating energy storage technologies for wind power integration," *Solar Energy*, vol. 86, no. 9, pp. 2707-2717, 2012/09/01/ 2012.

[7] X. Tang, X. Hu, N. Li, W. Deng, and G. Zhang, "A Novel Frequency and Voltage Control Method for Islanded Microgrid Based on Multienergy Storages," *IEEE Transactions on Smart Grid*, vol. 7, no. 1, pp. 410-419, 2016.

[8] G. Delille, B. Francois, and G. Malarange, "Dynamic frequency control support by energy storage to reduce the impact of wind and solar generation on isolated power system's inertia," *IEEE Transactions on Sustainable Energy*, vol. 3, no. 4, pp. 931-939, 2012.

[9] M. G. Molina and P. E. Mercado, "Power Flow Stabilization and Control of Microgrid with Wind Generation by Superconducting Magnetic Energy Storage," *IEEE Transactions on Power Electronics*, vol. 26, no. 3, pp. 910-922, 2011.

[10] D. Nikolic and M. Negnevitsky, "Practical Solution for the Low Inertia Problem in High Renewable Penetration Isolated Power Systems," *IEEE Power & Energy Society General Meeting (PESGM)*, 2018, pp. 1-5.

[11] J. Alipoor, Y. Miura, and T. Ise, "Power System Stabilization Using Virtual Synchronous Generator With Alternating Moment of Inertia," *IEEE Journal of Emerging and Selected Topics in Power Electronics*,

vol. 3, no. 2, pp. 451-458, 2015.

[12] M. Dreidy, H. Mokhlis, and S. Mekhilef, "Inertia response and frequency control techniques for renewable energy sources: A review," *Renewable and Sustainable Energy Reviews*, vol. 69, pp. 144-155, 2017/03/01/ 2017.

[13] K. V. Vidyanandan and N. Senroy, "Primary frequency regulation by deloaded wind turbines using variable droop," *IEEE Transactions on Power Systems*, vol. 28, no. 2, pp. 837-846, 2013.

[14] M. A. G. d. Brito, L. Galotto, L. P. Sampaio, G. d. A. e. Melo, and C. A. Canesin, "Evaluation of the Main MPPT Techniques for Photovoltaic Applications," *IEEE Transactions on Industrial Electronics*, vol. 60, no. 3, pp. 1156-1167, 2013.

[15] J. Hamilton, M. Negnevitsky, X. Wang, and S. Lyden, "High penetration renewable generation within Australian isolated and remote power systems," *Energy*, vol. 168, pp. 684-692, 2019.

[16] J. Hamilton, A. Tavakoli, M. Negnevitsky, and X. Wang, "Investigation of no-load diesel technology in isolated power systems," in *Power and Energy Society General Meeting (PESGM)*, pp. 1-5: IEEE, 2016

[17] O. Tremblay and L.-A. Dessaint, "Experimental validation of a battery dynamic model for EV applications," *World electric vehicle journal*, vol. 3, no. 2, pp. 289-298, 2009.

[18] L. Hannett, F. De Mlello, G. Tylinski, and W. Becker, "Validation of nuclear plant auxiliary power supply by test," *IEEE Transactions on Power Apparatus and Systems*, no. 9, pp. 3068-3074, 1982.

[19] K. Yeager and J. Willis, "Modeling of emergency diesel generators in an 800-megawatt nuclear power plant," *IEEE Transactions on Energy Conversion*, vol. 8, no. 3, pp. 433-441, 1993.

[20] R. Morris, H. Hopkins, and R. Borcherts, "An identification approach to throttle-torque modeling," *SAE Technical Paper* 0148-7191, 1981.

[21] N. Watson, A. Pilley, and M. Marzouk, "A combustion correlation for diesel engine simulation," *SAE Technical Paper* 0148-7191, 1980.

[22] D. N. Assanis, Z. S. Filipi, S. B. Fiveland, and M. Syrimis, "A predictive ignition delay correlation under the steady-state and transient operation of a direct injection diesel engine," *Journal of Engineering for Gas Turbines and Power*, vol. 125, no. 2, pp. 450-457, 2003.

A Technique For Calculation Of Life Limits Of Electrical Network Equipment

Alexander Nazarythev*, Dmitry Andreev

Petersburg Power Engineering Institute of Professional Development (PEIPK), Saint-Petersburg, Russia

***Abstract* — The main attention in the article is paid to the method of calculating the limiting values of the life of the main electrical equipment based on a comprehensive assessment of the actual condition of the equipment, that is, its condition index. The basic principles of the developed technique are given and a structural diagram of calculating the maximum service life of electrical equipment is shown. A general model is proposed for calculating the resource limits of electrical equipment based on a linear approximation of the state index change function. The applicability of this method is illustrated by an example of calculation for a transformer unit.**

***Index Terms* — main electrical equipment, service life, condition index function.**

Introduction

A significant portion of the main electrical equipment (EE) of power systems in the Russian Federation (oil-filled power transformers, high-voltage circuit breakers. etc.) has reached or is approaching its life limit.

This paper considers the basic results of developing a technique for determining the EE life limits (hereinafter referred to as the "technique"), which is to be used by electricity network companies in Russia. The application of this technique will allow selecting the electrical equipment for retrofitting and upgrading based on the level of equipment condition and forecasts on its lifetime extension beyond the rated limits. This technique is based on the developed, adopted and approved algorithms and models. It involves the automated systems and other components of the production asset management systems and complies with the current legislation of the Russian Federation [1 – 5].

An analysis of the papers [6 – 20] shows that the studies aimed at developing the calculation methods and determining the EE lifetime characteristics and life limits are carried out both in Russia and in other countries. It also indicates that the current transition towards a digital model of the energy industry contributes to the development and implementation of the methods based on the risk-oriented approach to making decisions on retrofitting and upgrading. Thus, it follows that the development of a technique for determining the EE life limits is an urgent issue.

II. Methodology

According to the Decree of the Russian Government [1], the technical condition index (CI) of electrical equipment should be determined and reliably define a technical condition of equipment and its changes within a stated range. It should have a clear technical sense and a single interpretation. The index of equipment (technical) condition is an integrated indicator of equipment state, which is a single value that incorporates the values of some other indices of the condition and is convenient for comparison and evaluation. For the calculation of the EE life limits, the said technical condition index is regarded as a known value determined according to the current regulations and specifications.

The electrical equipment is considered to have a limit condition when its condition index is equal to 0. The limit condition also corresponds to the expired service life of the equipment. The EE condition, when the condition index equals 1, corresponds to the condition of new equipment, whose operation has not started yet. The actual technical condition of electrical equipment deteriorates in the process of its operation. When the actions are performed according to the current system of maintenance and repair, the technical condition of the equipment improves. However, the general trend of the EE condition change over its total operation period is towards deterioration.

* Corresponding author.
E-mail: nazarythev@mail.ru

http://dx.doi.org/10.25729/esr.2019.02.0007
Received May 23, 2019. Revised July 18, 2019,
Accepted September 03, 2019. Available online October 31, 2019.

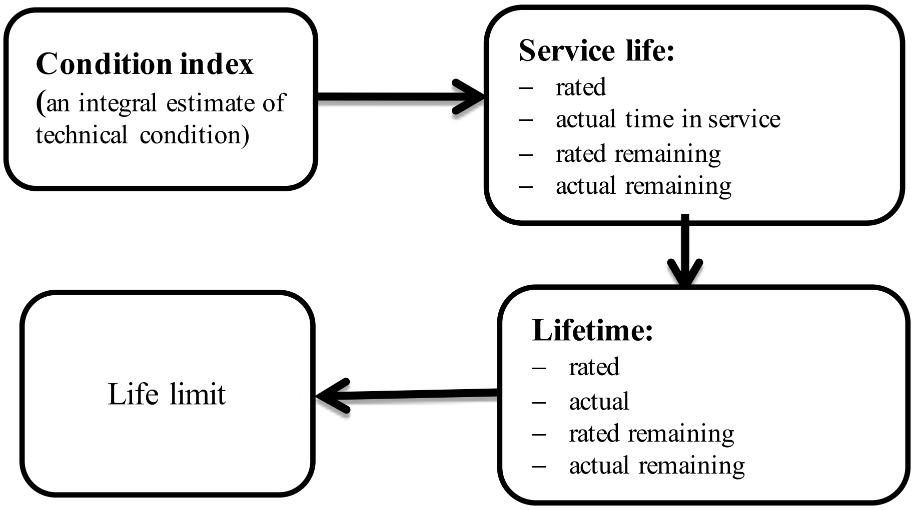


Fig. 1. A block diagram of the EE life limit calculation.

In [2], the authors have established a functional interdependence between the EE service life, lifetime, calendar time, life limit and technical condition level (the condition index value). The block diagram of determining the EE life limit is shown in Fig. 1:

Almost all failures of electrical equipment can be subdivided into unexpected and wear-out ones. Unexpected failures take place due to the effects of different unexpected factors, for example, such as the exposure to the elements (off-design wind loads, freezing rain, icing, etc.), acts of vandalism, failures caused by malfunction of some other equipment installed nearby, and others.

Wear-out failures result from an impermissible decline in the condition index of the electrical equipment and normally occur due to the accumulation and development of defects during the equipment operation, i.e., they develop gradually. The considered technique takes into account the wear-out failures by reducing the EE actual operating conditions to the rated ones by using the actual operating time in calculation expressions instead of the calendar time.

The operating conditions are reduced to the rated ones by using the expressions developed for calculation in [2]. These expressions relate the calendar time, actual service life, and the values of the EE condition index. The methods of calculating the actual time in service are presented in [3, 5]. The obtained value of actual time in service is used to calculate the rated remaining or actual remaining service life. By summing the actual service life and the remaining service life and by reducing the units for operating time measurement to time-based units, we can calculate the EE life limit. Now, we will define the above-mentioned terms.

Technical service life is the total operating time of electrical equipment from the start of its operation until its limit condition is reached.

Actual time in service is the time of electrical equipment operation under actual conditions. The actual remaining service life is the operating time of electrical equipment under certain conditions, starting with the moment of calculation until the limit condition is reached.

Rated service life is the time of electrical equipment functioning under rated (estimated, design) conditions. Rated remaining service life is the operating time of electrical equipment under rated conditions from the moment of calculations until the limit condition is reached.

The considered technique employs the mathematical models for calculating the EE life limits, given a varying degree of initial data completeness and composition. Further, we will consider a general model for calculating the life limit values, which takes account of all the probable changes in the values of the EE condition index. In a general case, the actual time in service depends on the operating time r and a change in the condition index with respect to function *S(r)*, and it is determined according to [10, 13]. Besides, the calculation should be made using the units for operating time measurement. In this particular case, the actual time in service *R* during the operating time t_c (the control point) corresponds to the EE actual lifetime Tc during the calendar time tc. The rated remaining lifetime is determined by the following expression:

$$T_{rem.0} = T_0 - T_c, \tag{1}$$

where T_0 is the EE rated lifetime.

If the electrical equipment is further operated under rated conditions, its life limit Tlim will be determined as follows:

$$T_{lim}=t_c+T_{rem\cdot 0}, \tag{2}$$

or:

$$T_{lim} = t_c+T_0-T_{lim} \tag{3}$$

If the electrical equipment is to be operated under the conditions other than the rated ones, its life limit will be determined by the following expression:

$$T_{lim} = t_c+T_{lim.rem}, \tag{4}$$

where $T_{lim.rem}$ is the EE remaining lifetime (calendar time) limit, which corresponds to its rated remaining lifetime $T_{0.rem}$, and is determined numerically from the equation:

$$T_{0.rem} = \int_{T_c}^{T_{lim.rem}+T_c} \frac{1-S(t)}{1-S_0(t)} dt \Rightarrow T_{lim.rem} = \dots \quad (5)$$

By expressing value $T_{lim.rem}$ from equation (5), we determine the time during which the electrical equipment can run under the supposed operating conditions until the limit condition is reached, i.e., when its actual remaining service life (actual lifetime T_{rem}) reaches the rated remaining service life (rated remaining lifetime $T_{0.rem}$).

Since it is rather difficult to forecast the electrical equipment operating conditions and parameters for the future period, it is appropriate to assume that after the control point the EE operating conditions will be the same as before the control point. Consequently, the EE technical condition and, accordingly, condition index will change in the same way. The extension of the life limit T_0 under known future conditions can be determined numerically using the equation:

$$T_0 = \int_0^{T_{lim.}} \frac{1-S(t)}{1-S_0(t)} dt \Rightarrow T_{lim.} = \dots \quad (6)$$

The study presented in [2] indicates that the absence of true retrospective data concerning the values of the EE condition index is a serious problem when determining the life limit. To enable the use of the proposed technique at the stage of its adoption, testing, and collection of the required input data on the equipment condition index, it is possible to apply a calculation model using the linear approximation of the condition index variation function *S(r)*:

$$\frac{1-S(t)}{1-S_0(t)} = \frac{m}{m_0} = A, \quad (7)$$

where m, m_0 are the coefficients of linear approximation of a set of data intended to obtain the functions of condition index variation for the actual operating conditions $S(t)$ and the rated operating conditions $S_0(t)$, respectively.

The actual time in service, in general, depends on the operating time r and the variation in the condition index with respect to function $S(r)$ [5]. In this case, the calculations are to be made using the operating time measurement units ($r = t$). Then, the actual time in service R during the operating time t_c (control point) will correspond to the EE actual lifetime during the calendar time t_c.

$$T_c = At_c, \quad (8)$$

Then the EE rated remaining lifetime will be:

$$T_{rem.0} = T_0 - T_c, \quad (9)$$

where T_0 is thee rated lifetime

or

$$T_{rem.0} = T_0 - At_c. \quad (10)$$

If the electrical equipment is further operated under the rated conditions, its life limit can be determined as follows:

$$T_{lim} = t_c + T_{rem.0}, \quad (11)$$

or

$$T_{lim} = T_0 - t_c(1-A). \quad (12)$$

If the electrical equipment is further going to be run under the conditions that differ from the rated ones, its life limit will be determined as follows:

$$T_{lim} = t_c + T_{lim.rem} \quad (13)$$

where Tlim.rem is the remaining lifetime (calendar time) limit of the electrical equipment, which corresponds to its rated remaining lifetime $T_{0.rem}$, and is determined as follows:

$$T_{lim.rem} = T_{0.rem}/A. \quad (14)$$

In this case, the EE life limit is determined by the following expression:

$$T_{lim} = t_c + \frac{T_{0,lim}}{A} \quad (15)$$

By expressing the value $T_{lim.\ rem}$ from equation (5), it is possible to determine a period during which the electrical equipment will still run under certain presumed operating conditions, before it reaches its limit condition, i.e., when its actual remaining service life (its actual lifetime T_{rem}) reaches its rated remaining service life (the rated remaining lifetime $T_{0.rem}$).

The life extension limit T_{lim} for a new piece of electrical equipment under the known future conditions can be determined by the following expression:

$$T_{lim} = T_0/A. \quad (16)$$

In the first approximation, in the case of no data available to obtain coefficient m0, it is appropriate to apply the following relation:

$$m_0 = \frac{1}{T_0} \quad (17)$$

The functional relationship between the condition index value and the operating time value is determined according to [2]. In doing so, time t is taken as a measurement unit of the operating time r.

The EE life limit should be recalculated whenever its condition index values change considerably (or when a new value of the condition index is obtained). The recalculation should include calculations before and after each type of repair (current, medium and major). This means that the periodicity of these calculations should correspond to the periodicity of EE condition index calculations. Accordingly, in this particular case, the data on the condition index should be approximated to obtain the relationship between the condition index variation and operating time, after each updating of the condition index data (after obtaining new values, after specifying old ones, etc.).

Additionally, the recalculation of the EE service life values is recommended when changes occur in the other data (including the rated data used in the models for calculation of the EE life limits).

Since the EE life limit is a forecast value, the final procedure for its calculation is determined by internal guidelines. The calculation of the EE life limits starts with the preparation of initial data. The basic initial data for this calculation are the information on the condition index values S and S_0 of a considered equipment unit. If the functions $S(t)$ and $S_0(t)$ are known, no additional initial data preparation is required and the calculation can be started. If either of the two functions, $S(t)$ or $S_0(t)$, is unknown, it should be determined using [5] by approximating the data according to the condition index values.

Depending on the completeness and quality of the initial data, it is necessary to choose a model for calculating the EE life limit. In the case that functions $S(t)$ and $S_0(t)$ are known, a general model is used for the calculation. In the initial stage of the proposed technique implementation, when there are no reliable retrospective data on the changes in the condition index depending on the EE operating time, it is appropriate to apply a model for calculating the life limit using linear approximation of data with respect to the condition index values for each unit of equipment.

After preparing the initial data and selecting a model for calculation of the equipment life limit, it is required to choose a certain date (hereinafter referred to as the "date of calculation"), when the calculation is to be made. The calculation for the considered electrical equipment requires that the following functions be known:

- Function $S_0(t) = S_{0.T}(t)$, where $S_{0.T}(t)$ is the basic function of the condition index variation depending on the operating time;
- Function $S(t) = S_T(t)$, where $S_T(t)$ is the actual function of the condition index variation depending on operating time.

Based on the date of EE commissioning, it is necessary to determine the EE calendar time in years, from the date of commissioning to the date of calculation:

$$t = t_c \tag{18}$$

Thus, the life limit is calculated in the following order:

1. The actual time in service (the actual lifetime) is calculated.
2. The value of the EE rated remaining service life is determined by applying either expression (1) or (10), depending on the selected model.
3. In the case it is planned to operate the electrical equipment under rated conditions, the remaining life limit corresponds to the rated remaining lifetime, while the total life limit is determined by either expression (2) - (3) or (11) – (12), depending on the selected model.
4. If it is further planned to operate the equipment under the conditions other than the rated ones, the EE remaining life limit is determined numerically from equation (5) or based on expression (14), and the total life limit is determined using either expression (4) or (15).

III. Example

Now, let us consider an example of the life limit calculations for the TMN-6300/110/10 transformer, which is installed in the power system of the "Komienergo" power grid company. Figure 1 shows the condition index change versus time for the above-mentioned transformer.

The time dependence of the condition index (p.u.) for the considered transformer at linear approximation has the form:

$$S(t) = 1 - 0.0267t \tag{19}$$

Given expression (7), coefficient A for this transformer is equal to 0.0267 / 0.04 = 0.67.

The calendar time of this transformer is t_c = 32 years. The actual lifetime, considering expression (8) will be determined as follows:

$$T_c = 0.67 \cdot 32 = 21.44 \text{ years.} \tag{20}$$

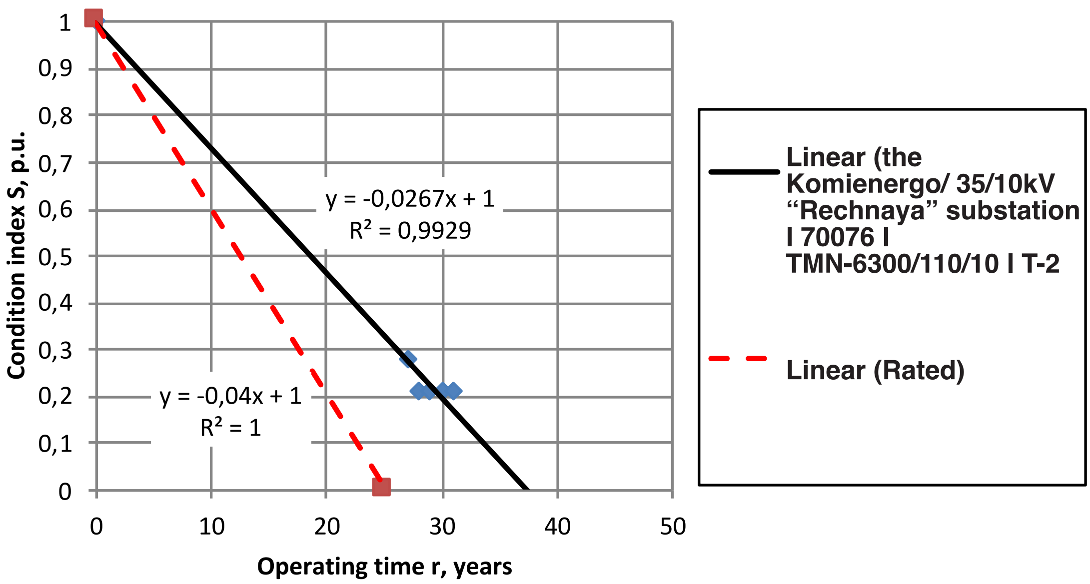


Fig. 1. Change in the condition index versus time for the TMN-6300/110/10 transformer (its rated lifetime is 25 years).

Then the rated remaining lifetime of this transformer, given expression (9), will be determined as follows:

$$T_{rem.0} = 25 - 21.44 = 3.56 \text{ years.} \quad (21)$$

If the said transformer is further operated under the rated conditions, its life limit will be determined by expression (11):

$$T_{lim} = 32+3.56 = 35.56 \text{ years.} \quad (22)$$

In the case that this transformer is operated under the conditions other than the rated ones (in this particular case, under the conditions it has been operated for 32 years), the life limit for this transformer will be determined based on expression (15):

$$T_{lim} = t_c + \frac{T_{0.rem}}{A} = 32 + \frac{3.56}{0.67} = 32 + 5.13 = 37.13 \text{ years.} \quad (23)$$

IV. Conclusions

The focus of the paper is a technique for calculating the EE life limits based on the integrated evaluation of equipment actual condition, i.e. its condition index. The basic principles of the developed technique are shown, and a block diagram of the EE life limit calculation is demonstrated. A general model is proposed to calculate the EE life limits based on the linear approximation of the condition index change function. The applicability of this technique is illustrated by a calculation example for an operating transformer unit.

References

[1] The Decree of the RF Government of December 19, 2016. No. 1401 "On the Comprehensive Determination of Technical/Economic Status Indexes for Power Industry Facilities, including the Indexes of the Physical Wear and Energy Efficiency of Power Systems Facilities and the Execution of Monitoring of these Indexes," (in Russian).

[2] D.A. Andreyev, A.N. Nazarychev, A.I.Tadzhibaev. "Determination of Probable Equipment Failures in Power Network Facilities based on Technical Status Evaluations," Edited by A.N. Nazarychev: *FGAEE "PPEIPD,"* p.194, St.Pb., 2017, (in Russian).

[3] A.N. Nazarychev, D.A. Andreyev. "The Methods and Mathematical Models of Comprehensive Evaluations of Electrical Equipment Status," The Ivanovo State Energy Institute, Ivanovo, p.224, 2005, (in Russian).

[4] A.N. Nazarychev, D.A. Andreyev. "The Methodological Foundations of Determining Operation Limits and the Scheduling of Power Industry Facilities Re-equipment," The Ivanovo State Energy Institute, *Ivanovo*, p.168, 2005, (in Russian).

[5] A.N. Nazarychev, A.I. Tadzhibaev, D.A. Andreyev. "Evaluation of Electrical Equipment Lifetime based on the Trends of Technical Status Changes," *"The Methodological Issues of Investigations Concerning the Reliability of Large Power Industry Systems."* Issue 68. – ISEM of the Siberian Branch of the Academy of Sciences, p.p. 613 – 623, 2017, (in Russian).

[6] The Order of the Ministry of Energy of Russia of July 26, 2017, No. 676 "On the Approval of Methods to Evaluate the Technical Status of Basic Technological Equipment and Power Transmission Lines of Power Stations and Power Systems."

[7] The Order of the Ministry of Energy of Russia of October 25, 2017, No. 1013 "The Rules of Organization of Technical Maintenance and Repairs of Power Industry Facilities".

[8] Nowlan F. S., Heap H. F. "reliability-centered Maintenance," San Francisco, *Dolby Access Press*, 1978.

[9] P.G. Grudinsky, S.A. Mandrykin, M.S. Ulitsky. "The Technical Operation of the Main Equipment Units of Power Stations and Substations," Edited by P.I.Ustinov, Moscow, *The "Energy" Publishers*, p.575, 1974, (in Russian).

[10] "Methodological Indications Concerning the Determination of the Depleted Switching Lifetime of Circuit Breakers during their Operation," M., *ORGRES*, p.20, 1992, (in Russian).

[11] B.N. Neklepayev, A.A. Vostrosablin. "The Methods of Evaluating the Switching Lifetime of Circuit Breakers during their Operation," The *"Promyshlennaya Energetika" Journal*, No. 1, p.p. 28 – 35, 1995, (in Russian).

[12] V.F. Sivikobylenko, V.I. Kostenko. – "Ways of Forecasting the Service Life of Electric Motors Insulation," *The "Elektricheskiye Stantsii" Journal*, No. 1, p.p. 53 – 57, 1977, (in Russian).

[13] F. Baselt, P. Franken – "Reliability and Technical Maintenance. A Mathematical Approach": Transl. from the German. M., *"Radio i Svyaz" Publishers*, 1988, (in Russian).

[14] B. Dillon, Ch. Singh. – "The Engineering Methods of Securing Systems Reliability": Transl. from English, M., *"Mir" Publishers*, 1984, (in Russian).

[15] Stoerungs- und Verfugbarkeitsstatistik – Berichtsjahr, FNN Forum Netztechnik und Netzbertrieb im VDE, Berlin, 2011.

[16] Todd Z.G. A Probability Method for Calculation. – *"IEEE Trans. Power. Apparatus and Systems"*, vol. 83, No. 7, p.p. 695 – 701, 1964.

[17] Kloeppel P.W. Berehnunggaverfahren fur die Bestimming der Versorgungssicherheit in electrischen Energienetzen. - "Energietechnik", 1964, 14, No. 7. – p.p. 289 – 296.

[18] V.V. Smekalov, A.P. Dolin, N.F. Pershina. "Evaluation of the Status and the Extension of Power Transformers Lifetime, Technical Re-equipment and Repairs of Power Facilities," Edited by V.V. Barilo, M.,

IPKgossluzhby, VIPKenergo, p.p. 120 − 136, 2002.

[19] B.V. Vanin, Yu.N. Lvov, M.Yu. Lvov et.al, "The Methodological Aspects of Evaluating the Degree of Aging of Winding Insulation in Power Transformers by Measuring the Degree of Polymerization," *"Elektricheckiye Stantsii" Journal*, No.1, p.p. 35 − 39, 2001, (in Russian).

[20] L.G. Kovarskiy. "The Calculations Foundations of Optimizing Electrical Equipment Repairs," *"Energoatomizdat," Leningrad Branch*, 1985, (in Russian).