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POWER SYSTEM STATE ESTIMATION ACCURACY ENHANCEMENT USING TEMPERATURE MEASUREMENTS OF OVERHEAD LINE CONDUCTORS

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Abstract

Power system state estimation is a process of real-time online modeling of an electric power system. The estimation is performed with the application of a static model of the system and current measurements of electrical quantities that are encumbered with an error. Usually, a model of the estimated system is also encumbered with an uncertainty, especially power line resistances that depend on the temperature of conductors. At present, a considerable development of technologies for dynamic power line rating can be observed. Typically, devices for dynamic line rating are installed directly on the conductors and measure basic electric parameters such as the current and voltage as well as non-electric ones as the surface temperature of conductors, their expansion, stress or the conductor sag angle relative to the plumb line. The objective of this paper is to present a method for power system state estimation that uses temperature measurements of overhead line conductors as supplementary measurements that enhance the model quality and thereby the estimation accuracy. Power system state estimation is presented together with a method of using the temperature measurements of power line conductors for updating the static power system model in the state estimation process. The results obtained with that method have been analyzed based on the estimation calculations performed for an example system – with and without taking into account the conductor temperature measurements. The final part of the article includes conclusions and suggestions for the further research.

Keywords: power systems, state estimation, transmission line, conductor temperature measurement, dynamic line rating.

1. Introduction

Estimation can be defined as a mathematical process of assigning a value to an unknown system state variable based on measurements performed for that system according to some criteria. Usually, the process involves inaccurate measurements that are redundant and estimation of the system state is based on a statistical criterion that assesses the true value of state variables to minimize or maximize a selected objective function [1]. In many physical systems, the system operating condition cannot be determined directly by an analytical solution of known equations using a given set of known reliable quantities [2]. However, a value obtained from the estimation process can be useful, because it is derived from the best information available [3]. In many systems, in order to unambiguously determine the operating condition, more measurements are taken than it is necessary. This redundancy is often purposefully designed into the system to prevent the effect of inaccurate or missing data occurring due to instrument failures. There are also such factors as high temperatures, moving parts or unfavorable conditions that can make the measurements difficult [2]. The least-squares estimation concept can be used in such cases as, for example, estimation of the missile or airplane trajectory based on inaccurate measurements of the position and velocity vector or of the grid signal frequency that is used to control an inverter connected to the electrical system [4]. The estimation process can be also useful for determination of the most probable

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mechanical state of overhead transmission lines based on measurements of a variety of quantities, such as the temperature, tension and tilt [5−6].

Power Systems (PS) are continuously monitored in order to maintain the normal and secure state of operating conditions. The state estimation function is also used for that purpose. It processes redundant electrical measurements in order to provide the optimal estimate of the current operating state. *State Estimators* (SE) also function as tools filtering incorrect measurements, data and other information received from the *Supervisory Control and Data Acquisition Systems* (SCADA). SEs also contain specific methods that are used for identification of bad data and errors related to the topology or grid element parameters [7]. The PS state estimation is a calculation procedure, whose task is to reproduce the most probable operating state of an electric PS based on the measurement results obtained from the system and the network system topology. The current PS state is determined by a state vector that is a vector of complex nodal voltages. The estimation result is the most probable state vector that makes possible determining all the variables for the analyzed system [8]. The SE is a very useful tool for the system operators and control engineers. Owing to the estimated system state it is possible to find incorrect meter readings, update current readings or retrieve missing measurement results. The last feature can be particularly useful in the case of a breakdown of some major energy meter related to the power exchange or connection between two systems of different operators. Current and verified representation of a power system makes a basis for further operations such as optimization provided by other tools or modules of the *Energy Management System* (EMS). The PS state estimation *a priori* assumes good recognition of the estimated system topology and individual parameters of the model elements such as power lines, transformers or capacitor banks. It should be pointed out that a model that is used for the estimation purposes is static and parameter values remain constant during estimation process [9−11]. Transmission line wire temperature measurements provided by the *Dynamic Line Rating* (DLR) devices can be used to enhance quality of the system model and thereby the estimation accuracy. In such a case, information about the current temperature of a conductor can be used to update the line resistance given by the model. Such an adjustment of the model makes it applicable for the system state estimation purposes.

2. The PS state estimation procedure and the effect of the model parameter errors on the estimation results

In order to fully define a power system, a set of complex phasor voltages has to be determined for each system bus and for that purpose state estimators typically include modules that provide the following functions: *Topology Processor* (TP), *Observability Analysis* (OA), *State Estimation* (SE) solution, *Bad Data Processing* (BDP) and *Error Processing* (EP). The TP collects the status data of circuit breakers and switches, and configures topology of the power system model. Next, the OA determines whether the SE solution can be obtained with the available set of measurements. The central point represents the SE solution, where the optimal PS estimate is determined based on the static network model and measurement results collected in the system. This step provides the best estimates for all line flows, loads, transformer taps and generator outputs based on the static system model. Next, the BDP detects the occurrence of gross errors in the set of measurement results. It identifies and eliminates bad measurements taking into account the measurement redundancy. The last function of the SE procedure is the EP that estimates various network parameters and detects structural errors in the network configuration, such as an incorrect breaker status. The estimation results are highly dependent on the power system model and, if a PS model includes incorrect topological information – *e.g.* an incorrect status of a switch or a circuit breaker - the estimation procedure usually produces large errors that eventually can be easily identified and corrected. However,

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identification of less evident errors such as branch impedance errors of line or transformer impedance can be not so easy, which can lead to permanent errors in the results provided by the SE [7]. The branch parameter values are stored in the PS model in the admittance matrix form [7, 13, 14] and remain constant throughout the estimation procedure. In this paper, the authors would like to focus on the transmission line series resistance that is highly dependent on the wire temperature and affects the estimation accuracy. The ambient conditions are considered to influence chiefly the line shunt conductance, but they also have an impact on the cooling conditions that determine the steady state temperature of conductors, which eventually leads to the wire resistance change. Analyses concerning the impact of the model parameter errors on the system state estimation can be found in [14–19]. In the power system state estimation, the measurement accuracy of active and reactive power is assumed to be 1.5% and 3.0% for the measurement ranges of ± 400 MW and ± 200 MVAR, respectively. The nodal voltage measurement accuracy is assumed to be 1.0% [8].

3. Dynamic line rating systems taking into account wire temperature measurements

Striving to take a better advantage of transmission line capacities has led to development of *Dynamic Line Rating* (DLR) technologies. Transmission capacities of overhead power lines strongly depend on weather conditions that determine the cooling conditions and thereby affect the temperature of conductors and their sagging. At present, ever growing interest in the questions of dynamic line rating can be observed. Many monitoring systems that make possible loading line conductors with a current that is higher than the rated current over a time period that depends on the current and forecasted weather conditions have been developed and successfully implemented [20–25]. The current condition of a power line is monitored by so-called DLR devices or DLR recorders. They are installed directly on the overhead line conductors and measure current electric parameters, *i.e.* the current values of voltage and current in the wire, together with other non-electric parameters, such as the surface temperature of the conductor [20, 21, 23], its expansion, stress or the conductor sag angle relative to the plumb line [22]. The mentioned measurement data, especially those of the wire temperature, make possible monitoring the current condition of line conductors and performing their controlled overloading in given weather conditions. There are various wire temperature measurement techniques as, for example, hot spot measurements [20–23] based on various physical phenomena, infrared camera image processing obtained by mapping the color information over an adequate temperature range [24] or a direct temperature measurement using a fiber optic cable. This method enables to measure the temperature along the entire length of the line. The measurement is carried out using the method of *Distributed Temperature Sensing* (DTS) based on the *Optical Time Domain Reflectometry* (OTDR) in a commercially available system RAMAN-OTDR [25]. The most interesting is the OTDR system, since it enables almost continuous wire temperature monitoring of a transmission line. Typical DTS system parameters are shown in Table 1.

Table 1. Typical DTS system parameters for monitoring the power line temperature.

PARAMETER	VALUE
Maximum measured distance	25 km
Spatial resolution along the wire	1 – 4 m
Temperature resolution	0.1 – 2.0 ^{0}C

Additional measurements of non-electrical quantities that make possible determining the allowed current and the overload duration are the measurements of weather parameters such as the air temperature, wind direction and speed, or solar radiation. The measurements of current atmospheric parameters of the conductor environment are performed at a single spot by weather stations that typically are installed on transmission towers. Such a station communicates via radio with a device installed on the conductor and makes the data further available for the SCADA systems [20–23]. Having such a data set and using popular formulas or solving differential heat transfer equations it is possible to determine the current and the time period till the conductor temperature reaches its boundary value. It is a method of dynamic line rating [20, 21]. The values measured by the DLR equipment make an additional source of information about the power system elements, that can be used not only for the controlled line overload but also to estimate the system state. The measured data obtained from the DLR devices and – chiefly – the temperature of line conductors can be considered as supplementary data that can be used to enhance accuracy of the estimation by updating the existing model of the system. The resistance of overhead line conductors varies as a function of the temperature, while power system models mainly use the notion of equivalent resistance or unit resistance of the conductors determined for a specified conductor temperature of 20°C [7, 13]. In such a case, the information about the current temperature of a conductor can be used to update the line resistance given by the model [26–30]. Such an adjustment of the model makes it applicable for the system state estimation purposes [29].

4. Modeling of HV power lines with taking into account temperature measurements

As mentioned above, aside with an adequate number of measurements the state estimation procedure also requires identification of the system topology to be determined based on the switch status obtained from the systems of *Supervisory Control and Data Acquisition* (SCADA) and a mathematical model of the system in the form of a nodal admittance matrix of complex elements $\underline{\mathbf{Y}}$ [7–13]. Such a model is encumbered with an error (a model uncertainty) resulting from inaccuracies of the modeled elements, *e.g.* in the case of a transmission line it can result from an inaccurate measurement of its length or current operation parameters such as the conductor temperature [7].

4.1. Resistance of HV line conductors as a function of temperature

For the purposes of load flow determination and system state estimation, the main system element, *i.e.* a transmission line, is modeled in the form of a four-terminal network of the π type shown in Fig. 1. The equivalent resistance R_L of the line can be determined based on its length given in kilometers and the unit resistance determined for 20°C.

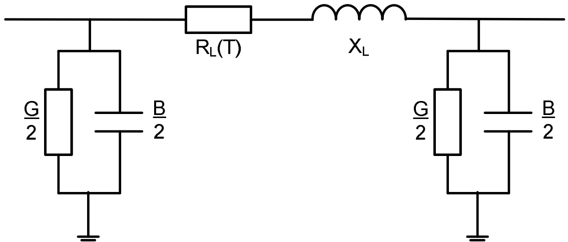

Fig. 1. The transmission line model in the form of a four-terminal network of the π type.

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Where: $R_L(T)$ – the transmission line resistance as a function of the conductor temperature, X_L – the reactance of the line, G/2 and B/2 – half values of the total conductance and susceptance of the modeled line, respectively.

The equivalent parameters of 110, 220 and 400 kV lines can be determined based on the kind of conductors, length of the lines, their geometry, *etc*. The transmission line resistance can be calculated using the popular formula (1). Calculations of resistances for line conductors for the temperatures other than 20°C can be performed using the formulas from (2) to (4) [12].

$$R_{DC20} = \frac{l}{\gamma S} = \frac{\rho l}{S}\ , \tag{1}$$

where: R_{DC20} – the conductor resistance (for the temperature of 20°C) determined for the direct current flow; l – the conductor length; γ – the conductor conductivity; S – the active surface of the conductor; ρ – the conductor resistivity. The conductor resistance values can be converted for any operating temperature using the formulas (2) and (3):

$$R_{DC}\left(T\right) = R_{DC20}\left(1+\alpha_{20}\left(T-20\right)\right) \tag{2}$$

or

$$R_{DC}\left(T\right) = R_{DC20}\frac{T+\beta}{20+\beta}\ , \tag{3}$$

where α, β – the material constants with the following dependence being valid:

$$\alpha_{20} = \frac{1}{20+\beta}. \tag{4}$$

For the most popular conductors, *i.e.* the ACSR (*Aluminum Conductor Steel Reinforced*) conductors, the parameters of the formulas from (1) to (4) assume the following values for the conductor temperature of 20°C: $\rho_{20} = 0.02826\frac{\Omega\cdot mm^2}{m}$ $\alpha_{20} = 0.00403\frac{1}{K}$ $\beta = 228.1\ K$. For the ACSR conductors, the R_{DC} value is by ca 1.5% higher because of the conductor design, *i.e.* their extended length resulting from the stranding. Conversion of the R_{DC} to R_{AC} values can be performed using the formula (5):

$$R_{AC} = 1.0123\ R_{DC}. \tag{5}$$

The formulas for the resistance of ACSR conductors as functions of the temperatures other than 20°C can be obtained with the formulas from (2) to (5):

$$R_{AC\,ACSR} = 1.0123 R_{DC\,ACSR}\left(1+\alpha_{20}\left(T-20\right)\right) = R_{ACSR20}\left(1+\alpha_{20}\left(T-20\right)\right) \tag{6}$$

or

$$R_{AC\,ACSR} = 1.0123 R_{DC\,ACSR}\frac{T+\beta}{20+\beta} = R_{ACSR20}\frac{T+\beta}{20+\beta}. \tag{7}$$

Estimation calculations use a static model of the system, where the resistance of transmission lines is given by constant values. In real operating conditions, the transmission line conductors are affected by variable weather conditions and the current passage that causes a release of energy that usually means emission of heat. The mentioned factors determine the temperature of a conductor, which directly affects its resistance. Thus, the real resistance of a system element differs from that of the model that is used for the estimation purposes [29].

The methods for considering temperature measurements of line conductors and their impact on the resistance of conductors have been presented in [28, 30]. Assuming that there is an adequately representative single-point measurement of the transmission line conductor temperature, the line resistance adjustment can be performed using (2) to (5). Unfortunately, the cooling conditions vary along the line length and, therefore, the DLR devices should be installed in a number of points along the line. With more than one measurement available, the temperature value T of the (6) and (7) can be determined using either (8) − if measurements taken at the near and far ends of the line are available, or (9) – when the measurement points are irregularly distributed along the line. Assuming a linear change between the temperature measurements, there are three ways of calculating the temperature and they can be described as follows:

$$T_{\mathrm{avg}} = \frac{T_{\mathrm{Beg}} - T_{\mathrm{End}}}{2}, \tag{8}$$

where T_{avg} – the average temperature calculated based on the temperature measurements (T_{Beg}, T_{End}) at the near and far ends of the line, respectively [24].

$$T_{\mathrm{Wavg}} = \sum_{\mathrm{a}=1}^{N-1} \left(\frac{T_{\mathrm{a}} + T_{\mathrm{a+1}}}{2} \frac{\Delta x_{\mathrm{a,a+1}}}{l} \right), \tag{9}$$

where: T_{Wavg} – the weighted average based on all available measurements and their locations along the line; N – the total number of measurement points; a – a measurement point (a = 1… N, based on the distance from the near-end of the line); T_{a} – the temperature measured at point a, $\Delta x_{\mathrm{a,a+1}}$ – the distance between the neighboring measurement points a and a + 1, l – the line length [30].

Using DLR systems based on the hot spot measurements [20–23], adjustment of the line model resistance can be performed using (6) to (9). As discussed earlier, the advantage of fiber optic systems such as the DTS-OTDR is that they enable a uniform distribution of the temperature measurement points along the line conductor and thus the value of T in (6) and (7) can be determined based on (10):

$$T_{\mathrm{avg}} = \frac{1}{N} \sum_{\mathrm{a}=1}^{N} T_{\mathrm{a}}, \tag{10}$$

where: T_{avg} – the average temperature along the line; T_{a} – the temperature measured at a single point a; N – the total number of measurement points along the line.

If the temperature measurements at the end points of the line are not available, the estimated values can be used based on the locations of the available measurements [30].

5. Estimation of the power system state with taking into account temperature measurements of transmission line conductors

The estimation process assumes a good recognition of the system, which means having a reliable model, where – aside with the transmission line reactance – the resistance of line conductors makes its basic parameter. Dependence of the conductor resistance on the temperature is a disturbance that can be measured by a DLR device and next used to update the existing model system. Even if the measurements are accurate, error encumbered parameters of the model can lead to non-optimal estimation solutions and a decreased accuracy of the estimation [7, 29].

5.1. Enhancement of the state estimation accuracy by the application of temperature measurements for updating the static model of the system

Estimation accuracy enhancement possibilities have been analyzed for the electric power system shown in Fig. 2, whose parameters are given in Table 2. The equivalent parameters have

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been calculated for individual lines using the voltage rating of V_{nom} = 110 kV and the basic power value of S_{base} = 100 MVA. The line susceptances have been neglected. The resistance values given in Table 2 have been determined for the temperature of 20°C [7].

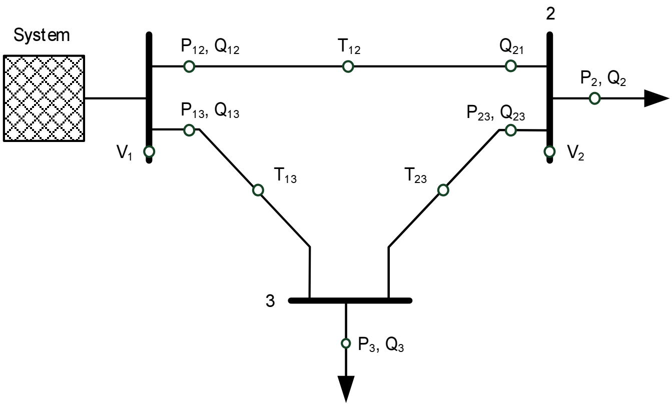

Fig. 2. An example electric power system with the marked available measurements to be used for the state estimation.

Table 2. The parameters of transmission lines of the reference power system model shown in Fig. 2.

LINE		RESISTANCE R_{20}		REACTANCE	
FROM BUS	TO BUS				
1	2	0.01 pu	1.21 Ω	0.03 pu	3.63 Ω
1	3	0.02 pu	2.42 Ω	0.05 pu	6.05 Ω
2	3	0.03 pu	3.63 Ω	0.08 pu	9.68 Ω

For the system shown in Fig. 2, the state vector is composed of 6 elements (11):

$$x^{\mathrm{T}} = [\theta_1, \theta_2, \theta_3, V_1, V_2, V_3], \tag{11}$$

where: $\theta_1, \theta_2, \theta_3$ – the phase angles at the nodes with $\theta_1 = 0$ being the phase angle at the node 1 assumed to be the reference node; V_1, V_2, V_3 – the voltages at the system nodes with V_1 = 1.0 being the voltage at the reference node. The values of the state vector elements obtained for a real state of the system shown in Fig. 2 are given in Table 3, while the available measured values are presented in Table 4.

Table 3. The state vector of the system shown in Fig. 2 for real operating conditions and the line conductor temperature of 40°C.

BUS	REAL SYSTEM	
	VOLTAGE	ANGLE
1	1.0000 pu	0.000°
2	0.9472 pu	–2.047°
3	0.9619 pu	–2.539°

The estimation accuracy analyses have been performed with the Matpower software [30] for a model, where the resistance values have been determined for the temperature of 20°C and then the resistances of individual lines have been updated using the available temperature measurement results.

Table 4. The measured values obtained during operation of the real power system shown in Fig. 2 for the line conductor temperature of 40°C.

MEASUREMENT	TYPE	VALUE	ERROR STANDARD DEVIATION σ_i
1	P_{12}	1.2445 pu	0.010
2	P_{13}	0.2942 pu	
3	P_{23}	0.2862 pu	
4	P_2	1.5000 pu	
5	P_3	1.0000 pu	
6	Q_{12}	1.1406 pu	
7	Q_{21}	–1.0971 pu	
8	Q_{13}	0.2437 pu	
9	Q_{23}	0.2248 pu	
10	Q_2	1.2800 pu	
11	Q_3	0.1000 pu	
12	V_1	1.0000 pu	0.004
13	V_2	0.9472 pu	

The number and locations of the DLR devices have been varied. The results of state estimation performed for the system shown in Fig. 2 using the *Weighted Least Squares* (WLS) method are given in Tables 5 and 6.

Table 5. Comparison of the state estimation results obtained for the system of Fig. 2 with varied locations of single line temperature measurement points.

BUS	ESTIMATION USING REFERENCE MODEL AT 20°C		REFERENCE MODEL UPDATED USING T_{12}		REFERENCE MODEL UPDATED USING T_{13}		REFERENCE MODEL UPDATED USING T_{23}	
	VOLTAGE $\hat{V}_i$	ANGLE $\hat{\theta}_i$	VOLTAGE $\hat{V}_i$	ANGLE $\hat{\theta}_i$	VOLTAGE $\hat{V}_i$	ANGLE $\hat{\theta}_i$	VOLTAGE $\hat{V}_i$	ANGLE $\hat{\theta}_i$
1	1.000 pu	0.000°	1.000 pu	0.000°	1.000 pu	0.000°	1.000 pu	0.000°
2	0.950 pu	–2.135°	0.949 pu	–2.081°	0.950 pu	–2.134°	0.950 pu	–2.137°
3	0.956 pu	–2.400°	0.956 pu	–2.387°	0.954 pu	–2.371°	0.956 pu	–2.396°
SSE	0.0270		0.0244		0.0357		0.0285	

Table 6. Comparison of the state estimation results obtained for the system shown in Fig. 1 and various combinations of two or three line temperature measurement points.

BUS	REFERENCE MODEL UPDATED USING T_{12} T_{13}		REFERENCE MODEL UPDATED USING T_{13} T_{23}		REFERENCE MODEL UPDATED USING T_{12} T_{13} T_{23}	
	VOLTAGE $\hat{V}_i$	ANGLE $\hat{\theta}_i$	VOLTAGE $\hat{V}_i$	ANGLE $\hat{\theta}_i$	VOLTAGE $\hat{V}_i$	ANGLE $\hat{\theta}_i$
1	1.000 pu	0.000°	1.000 pu	0.000°	1.000 pu	0.000°
2	0.950 pu	–2.134°	0.950 pu	–2.135°	0.949pu	–2.081°
3	0.954 pu	–2.371°	0.954 pu	–2.367°	0.954 pu	–2.353°
SSE	0.0341		0.0375		0.0358	

The performed estimation quality has been determined based on the *Sum of Squared Errors* (SSE).

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6. Conclusions

The analysis of the estimation results shown in Tables 5 and 6 indicates that the best estimation has been obtained for the scenario 2 (the R_{20} model updated with the measured temperature values of the line 1–2). For that scenario the lowest SSE value has been obtained regarding the real and the estimated state vectors. It is the heaviest loaded and the best metered transmission line of the analyzed system. Resistance adjustments performed with the temperature measurements for the remaining lines of the analyzed system have not yielded unambiguous results. The above considerations lead to the conclusion that the above discussed temperature-based adjustment of a model used for the state estimation purposes makes possible enhancing the estimation accuracy, but it depends on the system configuration, the current load flow and availability of the measured data. Additionally, it has been found that in a given electric power system there is an optimal location for a DLR device to measure the temperature of line conductors and use it to update the existing system model, significantly enhancing the estimation quality. The research on application of the temperature measurements of transmission line conductors to update the system model that is used for the estimation purposes as well as searching for the optimal location of the DLR equipment should be continued an extended onto more developed systems.

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