DIRECT MONITORING METHODS OF OVERHEAD LINE CONDUCTOR TEMPERATURE

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Abstract:

The concept of conductor temperature monitoring has gained in importance with development of advanced electricity networks whose main objective is to increase the capacity, efficiency and reliability of modern power systems. The methods applied to the conductor temperature monitoring of overhead lines can be roughly classified as direct and indirect. In direct methods for conductor temperature monitoring, the temperature is measured directly or by measuring a particular conductor parameter, which is temperature dependent such as sag, tension, conductor resistance, conductor distance from the ground, etc. In indirect methods for the conductor temperature monitoring, the conductor temperature is obtained by applying a specific mathematical model that as an input uses the measured values of weather parameters and line current. Basically, this paper focuses on the issues of direct methods for conductor temperature monitoring, thus providing an analysis of advantages and disadvantages of each method.

1 Introduction

To monitor the conductor temperature of overhead lines, different methods could be used. In order to understand the methods properly, the term conductor temperature should be clarified. Very often (especially in indirect methods), the term conductor temperature automatically considers the conductor as an isothermal body. This statement is not quite true because the conductor temperature changes radially and axially along the line. Especially at high current densities (greater than 2 or 3 A/mm^2), it is not advisable to ignore the radial and axial change of the conductor temperature. [1] Different methods for the conductor temperature monitoring enable spot measurements of the conductor temperature or longitudinal monitoring. Additionally, in terms of radial conductor temperature distribution, the surface conductor temperature, the core temperature, or the average conductor temperature (essentially representing an average of the surface and core temperature) could be measured.

The reasons of prime importance for the conductor temperature monitoring are detection and monitoring of hot points along the line, effective determination of the line rating, management in overload periods and ability to increase the transmission capacity of the existing lines. All these reasons could have an impact on the transmission system cost efficiency. [2]

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2 Direct monitoring methods of overhead line conductor temperature

Nowadays, several completely different methods for direct conductor temperature monitoring have been developed. In principle, the measured conductor temperature varies depending on the way in which the conductor temperature is measured (longitudinal or spot measurement) and on the principle applied to the measurement.
In the sections below, the following direct methods for conductor temperature monitoring are presented:

- direct monitoring of conductor temperature by temperature sensors,
- direct monitoring of conductor temperature by infrared cameras,
- direct monitoring of conductor temperature by optical fibers,
- direct monitoring of conductor temperature based on tension measurement,
- direct monitoring of conductor temperature based on sag measurement,
- direct monitoring of conductor temperature with phasor measurement units.

Temperature sensors, infrared cameras and optical fibers provide a direct measurement of the conductor temperature, while other methods infer the conductor temperature by measuring other line parameters and by using complex models of the line to determine its temperature. A good review of different direct methods for temperature monitoring is given in [3], [4].

2.1 Direct monitoring of conductor temperature by temperature sensors

The conductor temperature could be measured directly by means of temperature sensors. In this case, the measured temperature represents the surface conductor temperature measured at one spot. Temperature sensors used for conductor temperature monitoring are conventional contact temperature sensors attached to the line conductor, [5]. The most commonly used temperature sensors are resistance thermometers, thermistors, and thermocouples.
Resistance thermometers are based on the fact that the resistance of the material changes with respect to temperature. Thus, the conductor measurement is obtained from the resistance measurement. The resistance is measured as a ratio of voltage and current, thereby a small direct current (0,8 - 1 mA) through the sensor is applied. The most common materials for resistance thermometers are platinum, nickel, and copper.
Thermistors are very similar to thermometers. The main differences are the semiconductor materials they are made from and whether they have a negative or positive temperature coefficient. Compared to resistance thermometers, they are featuring higher sensitivity, faster response and a non-linear temperature versus resistance relationship.
Thermocouples are based on the Seebeck effect stating that due to a temperature gradient, a thermal electromotive force appears at the junction of two different materials. In this case, the temperature value is obtained from the measured thermal electromotive force.
The basic advantages of temperature sensors are:

- Wide availability of proven temperature sensors.
- The device is attached to the conductor, hence there is a limited error with regard to the measurement of conductor temperature. [5]
- Direct measurement of the conductor temperature suitable for the limitation of conductor strength loss at high temperatures (annealing). [6]
- Self-supplied temperature sensors.

The basic disadvantages of temperature sensors are:

- The measurement at one point is not a true representation of the conductor temperature at other points on the line. If the conductor temperature variations along the line are needed, the determination of a sufficient number and placement of the sensors is crucial. For this purpose, it is advisable to make some research into the line environmental and weather parameters changes (as, in general, the conductor temperature changes in the same section from span to span depending on local vegetation, orientation to winds etc.). [5, 7, 8]
- The temperature measured represents the surface conductor temperature. Thus, the radial change of the conductor temperature is not taken into account. However, the core temperature is a function of the surface conductor temperature and thermal input (Joule and solar heating) and could be determined according to a simplified formula if the line current and solar radiation is measured. Moreover, in some applications, the

solar radiation is assumed, which introduces an error in the estimation of the core temperature. [1, 5]

- The side effects of direct or close contact of the temperature sensor with an energized conductor could be mechanical (abrasions, sensor-conductor shock, vibrations, breaks), chemical (oxidations, galvanic actions), dielectric and electromagnetic (eddy currents), and thermal (self-heating). However, all these problems can be sorted out by a proper design and installation of the sensors. [9]
- Installation of sensors may require outage of the line (if live work is not allowed) and the sensors require periodic maintenance.
- High maintenance and purchase cost, although this fact is affected by the number of temperature sensors used. [8]

Many systems exist for commercial real-time conductor temperature monitoring based on temperature sensors.

One of the first commercial systems is the Power Donut (Usi) [10-11]. The sensor is self-powered by the magnetic field due to current in the power conductor and an internal lithium battery pack. The nominal low line current to operate is 60 A, and it runs on batteries for approximately 10 hours. When the line current is above 120 A, the battery recharges. It can measure the conductor temperature from -40 ºC up to 250 ºC with an accuracy of 1 ºC and resolution of 0,1 ºC. Apart from the conductor temperature, the device is used for measuring the line current, phase to ground voltages, and the angle of conductor inclination. The data is transmitted remotely via GSM/GPRS technology [13].

A similar monitoring system using Power Donut is called SMT (Arteche) [14]. In this case, the minimal low line current to operate is of 100 A, and the temperature range is from -20 ºC up to 250 ºC. Apart from the conductor temperature, it measures only the line current. As in case of Power Donut, the data is transmitted remotely via GSM/GPRS technology.

Another system is emo (micca) [12] which uses three temperature sensors and a reference sensor. The temperature range is from -25 ºC up to 210 ºC with an accuracy of 1,5 ºC. The sensor is self-powered with a battery pack. In this case, the data is transmitted remotely via TCP/IP technology.

Many other systems are available on the market like Ritherm (RIBE Group), FMC-T6 (General Electric), Power Line Sensors (Protura) etc. [4]

It should be emphasized that different systems compromise different temperature ranges, accuracy of temperature measurement, sensor dimensions, low line current to operate (for self-supply), type of remote data transmission, and electrical or non-electrical line parameters which are measured regardless of the conductor temperature. All of these parameters should be taken into account when selecting a commercial system in real life applications.

2.2 Direct monitoring of conductor temperature by infrared cameras

More recently, the possibility of using infrared cameras for conductor temperature monitoring of overhead lines is considered, [4, 9]. This technology enables the monitoring of the conductor surface temperature in a little larger field compared to the contact temperature sensors. Infrared cameras are widely used in maintenance procedures to determine poor connections and equipment failures on the line [15]. Although the application in conductor temperature monitoring is not sufficiently explored and there is no fully developed real-time system based on this method, some real-time systems for the detection of line poor connections are nevertheless being researched [16-17].

Infrared cameras detect the radiated infrared energy and generate a picture of spatial temperature distribution. By mapping the colours in the image to a suitable temperature range, it is possible to obtain temperature values at different places in the image. The most important parameters that affect the infrared camera accuracy measurement are [19]:

1) Emissivity coefficient determination

When measuring with an infrared camera, an incorrect setting of the emissivity coefficient value causes that the temperature values shown with the infrared camera differs from the actual values. This fact is especially true if the emissivity coefficient of the object has a low value. Standard values for overhead line conductors are given in various literatures like in [20, 21]. This coefficient could also be obtained with an infrared camera if another temperature sensor is used as a reference [19].

2) Reflected ambient temperature.

This parameter compensates for the ambient emissions that influence the object and are reflected from it to the infrared camera as well as the ambient emissions between the object and the infrared camera. When performing outdoor infrared recording, this parameter has to be set to the so-called sky temperature.

3) Distance between the object and infrared camera

This parameter is important because it compensates for the atmospheric absorption of the object's emissions.

4) Relative air humidity

This parameter compensates for the lowered atmospheric permeability due to increased humidity.

In overhead line monitoring, special attention when selecting the camera should be paid to the distance coefficient of the camera (the ratio between the distance and the diameter of the measured object) because the measured object is small and the measurement distance cannot be too close because of the installation limitation [16]. Moreover, the reflections in the interstices between circular wires of overhead line conductor depend on the angle used, which affects the accuracy of the measurement, although the surfaces of overhead lines are nearly 100 % reflective [22].

The basic advantage of infrared cameras in comparison to the contact temperature sensors is that cameras can be placed close to the line conductor, on a tower structure, for instance. This fact also reduces the installation cost of the system. The basic problem of this technology is not only that an additional algorithm for analysing the infrared image to determine the conductor temperature (neglecting the rest of image) is needed but also that correct camera parameters settings for all working conditions are difficult to achieve. Moreover, the influence of meteorological conditions (particularly the Sun), reflections, the presence of obstacles, the camera position, and the time needed for the image processing affect the accuracy and speed of the reconstructed conductor temperature (details on colour reconstruction is given in [23]). Therefore, the real-time conductor temperature monitoring by this methodology is hardly achievable and the infrared cameras are usually used only in the presence of workers who detect the conductor temperature by means of the infrared camera.

2.3 Direct monitoring of conductor temperature by optical fibers

This method of conductor temperature monitoring enables longitudinal measurement of the conductor temperature at distances of more than 20 km and with a measurement resolution of typically 2 m (depending on the physical principle adopted Consequently, this method takes into account the axial conductor temperature distribution [9, 25]. On the other hand, as the optical fibers are placed in a tube situated near the steel core, the measured temperature essentially represents the core temperature. In contrast to temperature sensors and infrared cameras which measure the surface temperature, this method enables measuring the radially increased core temperature [24]. This measurement is useful in dynamic line rating and sag/clearance calculations. In [24] a practical field research study on the longitudinal and spot measurement of the conductor temperature was made. It was shown that temperature sensors installed in low wind areas (sheltered valleys) detected a higher temperature of 6 º-10 ºC compared to the longitudinal measurements. Thus, in some applications (like hot spot determination), the longitudinal conductor temperature monitoring might not be the best solution.

Physical principles, on which the longitudinal temperature measurements with optical fibers are based, are [25]: Raman scattering, Brillouin scattering and Rayleigh scattering. The Brillouin scattering provides the best length range, with highest temperature sensitivity and relatively good measurement time and spatial resolution. This type of scattering is suitable for long transmission lines. In overhead line temperature monitoring applications, the Raman and Brillouin scattering are used [26]. Typically, the Raman scattering is used in optical time domain reflectometry (OTDR) [27] and optical frequency domain reflectometry (OFDR) [28], while the Brillouin scattering is used only in OTDR [29].

1) Raman scattering

Optical fibers are made of doped quartz glass, which is a form of silicon II oxide (SiO_2). With its solid amorphous structure, SiO_2 property allows fluctuations in the crystal molecules under the influence of heat. When the light falls into the heat induced oscillating molecules, the particles of light (photons) in interaction with molecules result in scattering of light, which is known as Raman scattering. The return scattering of light resulting from this process has three spectral components. One is Rayleigh scattering with the frequency of light source (laser), the second and third components are the Stokes and anti-Stokes components with a wavelength greater and smaller than photons that generated the effect. The intensity of anti-Stokes component is temperature dependent whereas Stokes is independent of temperature. Based on the relationship of Stokes and anti-Stokes intensity, the local temperature could be determined. The location of the measured temperature is determined from the return time of light, similarly as it is in the case when using a radar or sonar [25].

2) Brillouin scattering

Brillouin scattering refers to the scattering of a light wave by an acoustic wave due to a nonelastic interaction with the acoustic phonos of the medium and produces Stokes and anti-Stokes light components. The Brillouin frequency shift varies linearly with strain and temperature. Thus, the Brillouin scattering could be used for the longitudinal measurement of strain or temperature, but not for both of them simultaneously [25].

Optical fibers having a transverse refractive index gradient perform the longitudinal conductor temperature. The usage of optical fibers that have a transverse refractive index is very important because it ensures that the refractive index changes parabolically with respect to the conductor cross section. In this manner, the dispersion of light is reduced and the accuracy of measurements improved [28]. Optical fibers are placed in an optical phase conductor placed in the core.

The longitudinal temperature measurement system consists of the mentioned optical fibers as temperature sensors and a controller. In OTDR, the controller consists of a laser source, pulse generator for OTDR or code generator for code correlation or modulator, optical module, receiver and micro-processor unit. In OFDR, the controller consists of a laser source, high frequency mixer, optical module, receiver and micro-processor unit [28].

The approach of longitudinal conductor temperature monitoring by optical fibers has a high class accuracy of typically +/- 1 ºC or less and takes into account the efficiency of the axial temperature change. The sensors are immune to shock/vibration and electromagnetic interference. Moreover, the core temperature is measured and a distributed temperature sensor system eliminates the need for a separate communication system. [30] With this, the method seems to be a very acceptable solution for the conductor temperature monitoring of overhead lines. However, until now the technology has not found wide practical applications. This is due to the necessity of installation of optical fibers in the power conductors and the extremely high cost of the system [25, 31].

Many commercial real-time systems based on optical fibers exist. One of them is VALCAP (nkt cables) [32]. This system is based on Raman scattering in OFDR. It has a spatial resolution of 1 m, a temperature accuracy of 1 ºC and it enables monitoring of the conductor temperature over distances up to 200 km. The temperature is monitored inside the evaluation unit (where the controller is placed). From the evaluation unit, the data could be transferred by different methods (GPRS, LAN connection, high frequency communications, serial port, etc.). Thus, many options for remote and local display of the data are possible.

Another system is Fiber Optic Distributed Strain and Temperature Sensors (Oz optics) [33]. This system is based on Brillouin scattering in OTDR. It has a spatial resolution of 1 m (for 20 km fibers installation), a temperature accuracy of 0,3 ºC and it enables monitoring of the conductor temperature over distances up to 100 km. The data could be transferred via LAN networks or an USB port.

2.4 Direct monitoring of conductor temperature based on tension measurements

Tension system measures an average axial conductor temperature within a line tension section [9, 34]. The measured temperature is either approximately proportional to the average temperature of the conductor cross section, or in case of high temperature operation of steel-cored conductors, to the temperature of the core material [35]. Field studies [36-38] with different measurement equipment have shown that the local temperature in a given line section could be 10-25 % higher than the axial average. Thus, this method might not be suitable for hot spot measurements and conductor annealing prevention. A field study conducted in [27] has shown little differences in the practically measured average axial conductor temperature within a tension section obtained by this method and by optical fibers measurements. Although, some other studies [5] have showed that 90 % of measurements have a difference of -3 ºC to 7 ºC, which are decrementing at higher values of wind speed.

In this method, the conductor temperature is calculated from the measured tension. The tension is measured by load cells, which are mounted on selected dead-end structures along the transmission line. When two load cells are used at a dead-end structure, the tension and conductor temperature of both line sections (in two directions) could be monitored.

Load cells used in applications for the conductor temperature monitoring work on the principle of tension which is created when the material inside the load cell stretches and causes a change in its resistance. In this manner, by measuring the material resistance, it is possible to measure the acting tension. As in the case of contact temperature sensors, the resistance is measured as a ratio of voltage and current. Therefore, these converters require a certain power ensured from a battery or some other source [39].

In order to provide a correct conductor monitoring of a transmission line, the load cells should be placed in every line tension section. However, since the monitoring of every line section is impractical and very costly, it is important to monitor a sufficient number of line sections, depending upon the application. For line rating applications, a general recommendation is to monitor the critical sections because the section with the lowest rating determines the rating of the complete line. The basic criteria for critical line sections selection is based upon those sections being most sheltered by trees or terrain or sites where terrain forces the wind to be parallel to the conductor. Moreover, also critical line sections from the aspect of clearance violation should be considered. [5, 35, 40]

After obtaining the value of tension, the conductor temperature can be determined using the conductor state change equation for a line tension section expressed as follows [41]:

$$\frac{\bar{\sigma}_2}{E}-\frac{(g\cdot L_{id})^2}{24\cdot\bar{\sigma}_2^2}+\alpha\cdot(T_{c2}-T_{c1})+\Delta\varepsilon=\frac{\bar{\sigma}_1}{E}-\frac{(g\cdot L_{id})^2}{24\cdot\bar{\sigma}_1^2} \quad (1)$$

In Eq. (1) in case of flat terrain, the ruling span and equivalent stress at state 2 are calculated as follows:

$$L_{id}=\sqrt{\frac{\sum_{i=1}^{n}a_i^3}{\sum_{i=1}^{n}a_i^2}} \quad (2)$$

$$\bar{\sigma}_2=\sigma_2 \quad (3)$$

In Eq. (1) in case of rugged terrain, the ruling span and equivalent stress at state 2 are calculated as follows:

$$L_{id}=\sqrt{\frac{\sum_{i=1}^{n}a_i^3}{\sum_{i=1}^{n}\frac{a_i'^2}{a_i}}\cdot\frac{\sum_{i=1}^{n}\frac{a_i'^3}{a_i^2}}{\sum_{i=1}^{n}\frac{a_i'^2}{a_i}}} \quad (4)$$

$$\bar{\sigma}_2=\sigma_2\cdot\frac{\sum_{i=1}^{n}\frac{a_i'^3}{a_i^2}}{\sum_{i=1}^{n}\frac{a_i'^2}{a_i}} \quad (5)$$

For a parabolic approximation of the conductor catenary, the dependency of the tension measured by the load cell (at end support) and stress at state 2 is expressed as follows [56]:

$$F=\sqrt{F_h^2+F_v^2}\approx\sigma_2\cdot A+\frac{g^2\cdot L_{id}^2\cdot A}{8\cdot\sigma_2} \quad (6)$$

In Eq. (1) the conductor temperature at state 1 as the equivalent stress at state 1 are known parameters. Based on the tension measurement (F), it is possible to determine the stress at state 2 (σ_2) by solving the quadratic Eq. (6). Then, the equivalent stress at state 2 is calculated using Eq. (3) or Eq. (5). Finally, with these values, by iteratively solving Eq. (1) with a suitable mathematical method (like Newton-Raphson method), the conductor temperature at state 2 (T_{c2}) could be obtained. This temperature represents the measured conductor temperature by this system.

The conductor state equation assumes that there is perfect tension equalization at supports within the line section and a constant temperature for all spans within the tension section.However, the conductor temperature varies along the spans in the section, and there is a movement of dead-end supports and imperfect tension equalization due to uneven terrain, post insulators or short suspension insulators. This may make the ruling span assumption incorrect [42], [54]. Beside the most important mentioned, some other assumptions of the ruling span can be found in [56]. Additionally, in Eq. (1), the determination of creep could be a problem. Details on this topic are given in [30, 43]. Moreover, when taking into account the reduced weight (g), only the conductor weight is assumed. This fact is not quite true in case of ice or strong wind. For all these reasons, the solely use of Eq. (1) for the determination of the conductor temperature is not recommended. [5]

The alternative to the use of Eq. (1) is to set up a calibration function. The calibration function represents a relationship between the tension and conductor temperature. Calibration functions are calculated based on practical measurements in the observed tension section. When setting up a calibration function, the conductor temperature has to be measured by another method. Basic instructions and practical examples for setting up calibration functions are given in [5, 43, 44]. It is worth emphasizing that the calibration methods are different depending on the equipment used. Manufacturers of tension monitoring equipment should provide instructions on calibration procedures, their accuracy and resulting uncertainties. Moreover, the manufactures should give instructions on periodic calibrations due to changes on the line (structural movements, conductor creep etc.). [35]

In order to set up an accurate calibration function, the largest possible number of practical measurements should be carried out in different weather and line conditions. After obtaining the practical measurements, the calibration function is defined by applying curve-fitting methods, such as, for instance, the least square method.

The general form of the calibration function is as follows:

$$T_c = a + b \cdot F + c \cdot F^2 + d \cdot F^3 + e \cdot F^4 \qquad (7)$$

To set up Eq. (7), a minimum of five tension and conductor temperature measurements are needed. A general accuracy obtainable with this method is around 1 ºC with a resolution of 0,1 ºC.

The system of conductor temperature monitoring based on tension measurements consists of a power supply (usually solar panels and battery), load cells and data logger for measurement collection and communications [43, 44]. Also some systems for the calibration process adopt net radiation sensors (NRS). These sensors measure the temperature of the conductor when it carries no electrical current. With relation to [18] and [44], the principal advantages of this method for the conductor temperature monitoring are:

- The measured conductor temperature is an average temperature of all the spans between two tension towers, and the radial increment is taken into account.
- High accuracy for the use in a line section with multiple suspension spans having nearly the same tension and lengths.
- Unlike the conductor temperature, the tension is measured directly. Easy calculations from the tension measurement enable the sag and clearance determination. This could be useful in some applications.

The fundamental disadvantages of the described method are:

- Sensors are not self-supplied.
- Placement of load cells requires the line outage.
- Setting up calibration functions that accurately approximate all working conditions is complex and therefore recalibration may be required.
- Various span lengths in a tension section, mass of the load cell, weather conditions, creep and movements of insulators and tower structures affect the accuracy of the measured conductor temperature.
- High purchase, maintenance and installation costs. However, this is affected by the number of load cells used. [8]

A commercial tension monitoring system is CAT-1 (Nexas) [44-45]. This system is designed to automatically establish the relation between tension and conductor temperature. For the calibration process, the conductor temperature value is not measured directly but estimated from the temperature measured in the NRS. The system is designed to transfer remotely the data via GPRS.

2.5 Direct monitoring of conductor temperature based on sag measurements

This method is the same as the previous one in the type of conductor temperature measurement, but in this case, an extra sag-tension model is needed for the determination of conductor temperature.

In this case, the conductor temperature is measured from the monitored sag. There are several different principles for sag measurement. All the methods for sag measurement should have a minimal resolution, which is equivalent to a sag change caused by 1 °C conductor temperature change. [35] The basic principles for conductor sag measurement are the use of video camera, laser, radar, differential global positioning system technology (DGPS) and vibration sensors.

The first method for sag measurement is a video camera mounted on a line pole [47-48]. For measuring the sag, a label is attached to the line conductor and the camera is calibrated. The camera has an image of the target stored in memory which is than compared with the real-time image. The actual sag is determined by counting the difference in pixels of the current image and the one stored in memory. Apart from sag, the algorithm also determines the conductor clearance from the ground. The advantage of this technology is that the camera is mounted on the pole and not on the conductor (as in case of load cells). However, if live work is not allowed, the placement of the target requires the line outage. A typical resolution of sag measurements is of 0,6 cm.

Laser technology can be equally successful for measuring the conductor sag [18, 49, 50]. The laser is fitted on the ground approximately 20 m away from the line. In these systems, a properly driven scanning beam causes a backscattered intensity from the observed conductor. The sag is determined from the relative temporal position of the backscattered signal in respect to the scanner driving signal. Laboratory tests show that the measurement accuracy is around 6 mm. [50] Also, special lasers have accuracy in the submillimeter range. [51] However, since some obstacles may occur (like animals) between the laser and the line and it is a question of an expensive technology (possibility of theft), this type of measurement is not suitable without staff presence.

The alternative to laser technology for conductor sag measurement is the radar [18]. This technology is poorly researched in overhead line applications. As laser technology, this measurement method is not suitable to be used in real-time but more for exploring other measurement methods.

The DGPS method is a direct method that measures the conductor sag from the altitude information obtained by the global positioning system (GPS) device [51-52]. In this method, the GPS device with the communication module is mounted on the line conductor at the middle of a span. The use of DGPS compensates greatly errors common to all local GPS receivers. The following features accounts for the use of DGPS [5]: nanosecond-order precise time tagging, accuracy, compactness, portability, low cost, and operation in all weather conditions anywhere on Earth. A field study [51] showed that the method has an accuracy of approximately 2,54 cm for sag measurement. This method could be used for obtaining real-time sag measurements.

Another solution for sag monitoring is the use of vibration sensors [5], [54]. These sensors attached directly on the power conductors can evaluate the real-time sag of a span without any additional data. After measuring the fundamental vibration frequency, the sag (parabola conductor catenary approximation) is obtained as follows [54]:

$$f_x = \frac{g_r}{32 \cdot f_0^2} \tag{8}$$

All the external conditions (creep, suspension movements, snow/ice etc.) affect the fundamental frequency and thus the measured sag. Moreover, the sensors could be installed at any point of the span because vibrations travel along the entire conductor. The precision of this system is of 0,6 % for the sag estimation of any magnitude. [4] A field research [54] reported a maximum error of 20 cm for measured sag in range from 0 to 25 m.

Apart from the described sag measurement methods, some other methods exist:

- Use of angle measurement devices that calculate the actual sag from the conductor inclination angle [53].
- Use of sensors that measure the conductor clearance from the ground and then calculate the actual sag [55].

Based on the conductor sag measurement, the conductor temperature could be determined from Eq. (1). At first, from the known sag in a span of tension section (labelled by x), the equivalent stress at state 2 is calculated. This is done for flat terrain by Eq. (9), while for rugged terrain by Eq. (10).

$$\bar{\sigma}_2 = \frac{a_x^2 \cdot g}{8 \cdot f_x} \tag{9}$$

$$\bar{\sigma}_2 = \frac{a_x \cdot a_x^{'} \cdot g}{8 \cdot f_x} \cdot \frac{\sum_{i=1}^{n} \frac{a_i^{'3}}{a_i^2}}{\sum_{i=1}^{n} \frac{a_i^{'2}}{a_i}} \tag{10}$$

In Eq. (9) and Eq. (10), for sag calculation, a parabolic approximation of the conductor catenary is assumed. There are some limitations in using oversimplified sag models. Usually, the parabola

approximation gives satisfying results for spans approximately up to 300 m, [56-57].
After calculating the equivalent stress at state 2, the conductor temperature is obtained by iteratively solving Eq. (1) as in the case of previously described method. Moreover, all the errors introduced by the ruling span assumption are present also in this method.
In this method, the usage of calibration functions is recommended. For this method, the calibration function represents the relationship between sag and conductor temperature and can be expressed as follows:

$$T_c = a + b \cdot f_x + c \cdot f_x^2 + d \cdot f_x^3 + e \cdot f_x^4 \quad (11)$$

To set up Eq. (11), a minimum of five sag and conductor temperature measurements is needed. The calibration function is set similarly as in the previously described method. Good instructions for setting sag-conductor temperature functions are given in [5, 58].
The conductor temperature monitoring based on sag measurements has basically all the advantages of the tension monitoring, but with lower installation costs. [8] However, in this case the sag is measured, and the tension as the clearance could be calculated indirectly. The disadvantages of the system depend upon the method adopted for sag measurement. Although, in all the methods, an error is introduced due to various span lengths in a tension section, weather conditions, creep and movements of insulators and tower structures, the calibration function setting problem is nevertheless still present.
A commercial real-time conductor temperature monitoring based on sag measurement is Span Sentry (EDM). This system consists of a video camera, power supply (solar panels and batteries) and a data logger. The accuracy in sag measurement is of 15 mm. It transfers remotely the data via GSM IP networks, local radio or fiber optic configurations.
Another commercial system is Ampacimon [54]. This system uses a self-powered vibration sensor which transfers the data via GSM technology. This device also measures the line current and wind speed. The wind speed is determined at the point of installation from the conductor vibration frequency analysis. These extra measurements are useful in line rating applications.

2.6 Direct monitoring of conductor temperature by phasor measurements units

Conductor temperature could be monitored directly by installing phasor measurement units (PMUs) [59-62]. This method determines the average conductor temperature along the entire transmission line [59]. However, since the electrical resistance is dependent on the average conductor temperature [1], in terms of radial aspect, a slightly lower temperature than the core temperature is determined. Like sag and tension measurements, this method might not be suitable for hot spots determination.
PMU calculate the conductor temperature from the line series resistance [62]. PMUs measure the voltage and current phasors at the beginning and end of the line, and from these data, the characteristic line impedance and the propagation constant are determined as follows [62]:

$$\vec{Z}_C(T_c) = \sqrt{\frac{\vec{U}_S^2 - \vec{U}_R^2}{\vec{I}_S^2 - \vec{I}_R^2}} \quad (12)$$

$$\vec{\gamma} \cdot l(T_c) = \ln\left(\frac{\vec{U}_S + \vec{Z}_C(T_c) \cdot \vec{I}_S}{\vec{U}_R - \vec{Z}_C(T_c) \cdot \vec{I}_R}\right) \quad (13)$$

The line series impedance and resistance are then calculated by the following equations:

$$\vec{Z}(T_c) = \vec{Z}_C(T_c) \cdot \vec{\gamma} \cdot l(T_c) \quad (14)$$

$$R_{ac}(T_c) = \mathrm{Re}(\vec{Z}(T_C)) \quad (15)$$

The series line resistance could also be expressed in terms of a reference value as follows:

$$R_{ac}(T_c) = R_{REF} \cdot \left(1 + \beta \cdot (T_C - T_{REF})\right) \quad (16)$$

Finally, from Eq. (16), the conductor temperature is obtained [60-61]:

$$T_C = T_{REF} + \left[\frac{R_{ac}(T_c)}{R_{REF}} - 1\right] \cdot \beta^{-1} \quad (17)$$

The basic problem in using Eq. (17) is the determination of β, T_{REF}, R_{REF} and the selection of these three elements directly affects the conductor temperature measurement accuracy. Typically, the coefficient β is obtained from literature as a table value depending on the conductor material (like [1], [63]). The value of R_{REF} could be calculated according to standard methodologies for a given T_{REF} if the length of the conductor at T_{REF} is known (from measurements or by calculation). A good reference for the calculation of series AC line resistance per unit length is given in [63]. Another possibility is to estimate R_{REF} with the PMU. This estimation is possible when a longer line outage (few times greater than the thermal constant) appears and the line is energized again. In that moment, T_{REF} could be assumed to be equal to the ambient temperature (in the line vicinity) and R_{REF} could be determined from the PMU readings [18].

The accuracy of this method is also highly dependent upon the accuracy of the selected voltage and current transformers used for the phasors measurements. In [64] the impact on measurement accuracy of instrument transformers is discussed. A general conclusion is that the error of the voltage transformer is approximately constant, while for low line currents, the current transformers introduce a substantial error in the measured resistance, and thus also in the temperature estimation. Alternatively, the system could be calibrated to compensate these problems. Different methods for accurate impedance estimation by PMUs are described in [65].

Beside all the uncertainties in conductor temperature measurement by PMUs, this is the only technique which measures the average temperature of the entire line. Moreover, the monitoring is done in real-time with a time resolution of 1 s [18]. However, the overall costs for application of PMUs and their integration into the existing systems are very high. Thus, this method has a limited practical application.

3 Conclusion

This paper presents different direct methods for monitoring conductor temperature of overhead lines. From the analysis of different methods, it can be concluded that large differences appear not only in the principle adopted for conductor temperature measurement but also in terms of what the measured temperature represents. In some cases, the measured temperature represents a single value spot measurement or an approximate value, which is valid for a line segment. In others, the temperature is measured longitudinally and the data on the axial distribution of conductor temperature are obtained. Moreover, if viewed radially, the measured value can represent the surface, core or average conductor temperature. All the considered methods have their advantages and disadvantages, which may represent a limitation in practical applications. Currently, for hot spot measurement and conductor annealing prevention, temperature sensors (if properly installed) represent the best solution. Temperature sensors could also be used for line rating calculations, but, in such cases, the appropriate sensor size and its positioning are of crucial importance. Tension and sag monitoring systems are accurate for overhead line sections having nearly equal tension in suspension spans, and are generally used in line rating applications. Due to economic reasons, these methods based on optical fibers and PMUs have, however, limited practical application.

Nomenclature

a, b, c, d, e - calibration function constants
a_i - i-th span length [m]
a'_I - i-th length between suspension points [m]
a_x -span length in the observed span [m]
a'_x -length between suspension points in the observed span [m]
A - conductor cross section [m^2]
α - linear expansion conductor coefficient [$°C^{-1}$]
β - temperature coefficient of conductor resistance [$°C^{-1}$]
$\vec{\gamma}$ - propagation constant [1/m]
E - Young modulus [N/mm^2]
f - conductor sag [m]
f_x - sag in the observed span[m]
f_0 - fundametal conductor vibration frequency[s^{-1}]
F - tension at end support [N]
F_h - horizontal component of tension at end support [N]
F_v - vertical component of tension at end support [N]
g - reduced conductor weight [$N/mm^2 \cdot m$]
g_r - gravitational acceleration [m/s^2]
$\vec{I}_R, \vec{I}_S$ - current phasors at the beginning and end of the line [A]
l - length of the conductor [m]
L_{id} - ruling (equivalent) span length [m]
n - number of span in a tension section
R_{ac} - series AC line resistance [Ω]
R_{REF} - reference series AC line resistance [Ω]
T_{REF} - reference temperature [°C]
T_c - conductor temperature [°C]
T_{c1}, T_{c2} - conductor temperature at state 1 and 2 [°C]
σ_1, σ_2 - stress at state 1 and 2 [N/mm^2]
$\bar{\sigma}_1, \bar{\sigma}_2$ - equivalent stress at state 1 and 2 [N/mm^2]
$\vec{U}_R, \vec{U}_S$ - voltage phasors at the beginning and end of the line [V]
Z - series AC line impedance [Ω]

Z_c - characteristic line impedance [Ω]
$\Delta\varepsilon$ - creep
ω - angular frequency [rad/s]

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