A NOVEL STATE ESTIMATION MODEL FOR DISTRIBUTION SYSTEMS

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Abstract - A new model for distribution system state estimation is presented. The essence of the method is the combination of load models and real-time measurements. The novelty compared to the previous techniques is that emphasis is put to the limiting technical factors. That is, not only the load flows and currents are estimated, but also the temperatures of the power system components are assessed and compared to the critical ones. The monitoring of voltage is based on the voltage received by the customers, which is compared to the accepted voltage levels given in power quality standards. The new method is also optimised with regard to the computation speed, so that a real-time application is possible.

Keywords: distribution systems, state estimation, load carrying capacity

1 INTRODUCTION

Nowadays the electrical network companies put high effort in utilizing their distibution capacity into the full extent. For this of major importance is a good knowledge of load currents and other technical limiting quantities. The final objective is to know the margin between ultimate technical limits and the actual distribution system state. For this, different state estimation techniques have been developed.

State estimation is a well known function in transmission network analysis. However, in distibution systems the idea is relatively new and practical applications are not that common. One reason for this is that, contrary to the circumstances in transmission systems, in distribution networks there are no excessive measurements, but one has to rely on both measurements and load statistical models.

The combination of power system measurements and load models has previously been studied by Handschin [1,2]. Their approach focused on a rather extensive use of power system measurements and normalised load curves of seven customer groups. These customer groups were assumed to be independent of each other and no statistical deviations were presented.

Seppälä proposed a method, where the number of load models was increased to 46 and the random variation of load was taken into account as a statistical deviation of the hourly demand [3]. He also proposed a method, by which the load models can be fitted to the load measurements, in order to reduce the errors caused by unknown external factors. The loads presented by different load models are assumed to be independent of eact other.

An estimation algorithm of distribution load, incorporating both the statistical deviation and the correlation of loads between different customers, has been proposed by Ghosh et. al [4]. This algorithm fits the computed load currents and bus voltages to the direct measurements obtained from the network. For accurate operation, it requires a comprehensive number of measurements, since no type load models are used.

The technique presented in this paper combines the main properties of the above mentioned solutions. The novelty compared to the previous techniques is that emphasis is put to the limiting technical factors. That is, not only the load flows and currents are estimated, but also the temperatures of the power system components are assessed and compared to the critical ones. The monitoring of voltage is based on the voltage received by the customers, which is compared to the accepted voltage levels given in power quality standards. The new method is also optimised with regard to the computation speed. Thanks to the continuous computation the reaction time in the case of major changes is only some seconds.

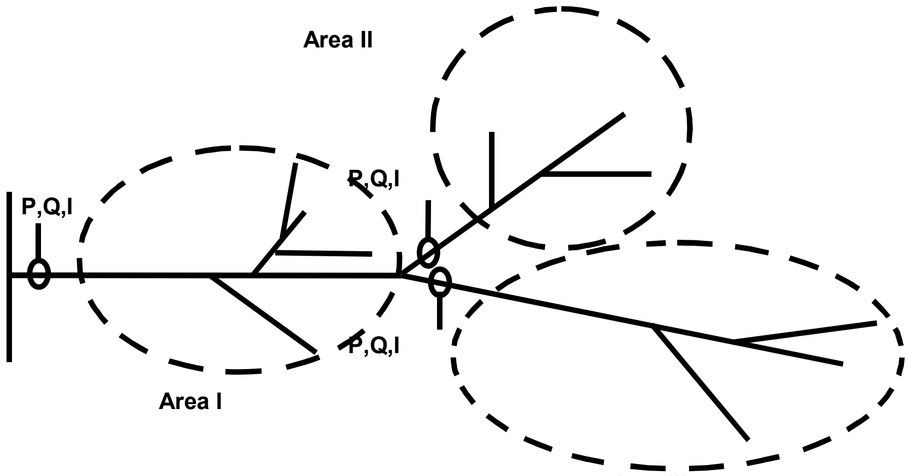

Figure 1: The estimation areas in a distribution feeder. In the example case there are three areas (Area I …Area III).

2 ESTIMATION OF CURRENTS AND VOLTAGES

The key idea of current estimation is the formation of estimation areas. These are the smallest parts of the network, which can be limited by measurements (Fig. 1). The computation is made using current phasors. In the case, that some of the measurent is a power measurement, it is transformed into the current value by using the measured or modelled power factor.

Suppose that $\mathbf{I}_{meas}$ is the vector of measured currents in the area concerned, $\mathbf{I}_{load}$ is the vector of load node currents obtained by type class load models and **e** and **v** are the corresponding error phasors. Now the relation between measured or modelled quantities and the estimated node currents can be written as follows:

$$\begin{bmatrix} I_{meas} \\ I_{load} \end{bmatrix} + \begin{bmatrix} e \\ v \end{bmatrix} = [A] \begin{bmatrix} I_{e,m-1} \\ I_{e,l} \end{bmatrix} \tag{1}$$

$$[A] = \begin{bmatrix} 1 & 1 & \cdots & 1 \\ 1 & 0 & 0 & 0 \\ 0 & 1 & 0 & 0 \\ 0 & 0 & \ddots & 0 \\ 0 & 0 & 0 & 1 \end{bmatrix}$$

Where $\mathbf{I}_{e,m-1}$ includes the estimated currents in the measurement points less the current in the feeding point of the area, i.e. the measured currents flowing downstream from the area, and $\mathbf{I}_{e,l}$ includes the estimated node load currents. The above equation can be solved for the best fit of these estimated currents by minimising the error terms as follows:

$$\min\left\{ \begin{bmatrix} \mathbf{e} \\ \mathbf{v} \end{bmatrix}^{\mathbf{T}} \mathbf{R}^{-1} \begin{bmatrix} \mathbf{e} \\ \mathbf{v} \end{bmatrix} \right\} \tag{2}$$

Where **R** is the matrix containing the covariances of the measurements and load currents. Assuming these variables independent from each other we obtain a diagonal matrix with variances of the measurement errors and the modelled load currents. The solution for Eq.(2) is found by solving its partial derivatives with regard **e** and **v**, which results to the load current estimates as follows [3]:

$$I_{e,l,i} = I_{load,i} + \frac{\sigma^2_{load,i}}{\sum \sigma^2_{meas,j} + \sum \sigma^2_{load,j}} \Delta I \tag{3}$$

Where $\sigma_{meas,i}$ is the standard deviation of the measurement i, $\sigma_{load,i}$ is the deviation of load current in node i, obtained by load models, $I_{load,i}$ is the load current in node i, produced by load models, $I_{e,l,i}$ is the estimated load current in node i and ΔI is the sum of current errors [**e**,**v**], which is in practice equal to the difference of measured and modelled currents.

The next step of state estimation algorithm is the correction of voltages. This is done in a similar way to the node currents, but now the estimated quantity is the branch voltage drop $\Delta U_{br,e}$:

$$\begin{bmatrix} \Delta U_{meas} \\ \Delta U_{br} \end{bmatrix} + \begin{bmatrix} e \\ v \end{bmatrix} = \begin{bmatrix} C \\ I_n \end{bmatrix} \left[\Delta U_{br,e} \right] \quad (4)$$

Where ΔU_{meas} is the vector of measured voltage drops in the line locations, ΔU_{br} is the vector of voltage drops in the individual line sections (or branches), computed using estimated currents, **e** and **v** are the corresponding error phasors, n is the number of line sections and I_n is a unit matrix with dimension n. **C** is a connectivity matrix, which relates the measured voltage drops to the voltage drops in line sections. Since the first one is a linear sum of a group of voltage drops in line sections, the elements of **C** are ones and zeros.

When the above equation is solved using general least squares estimation technique, the new branch voltage drops are obtained as follows, Eq. (5):

$$\left[\Delta \hat{U}_{br,e} \right] = \left[\begin{bmatrix} C \\ I_n \end{bmatrix}^T R^{-1} \begin{bmatrix} C \\ I_n \end{bmatrix} \right]^{-1} \begin{bmatrix} C \\ I_n \end{bmatrix}^T R^{-1} \begin{bmatrix} \Delta U_{meas} \\ \Delta U_{br} \end{bmatrix}$$

Where **R** is now a matrix containing the covariances of the measured and estimated voltage drops. Assuming these independent we obtain a diagonal matrix with variances of the measurement errors and the modelled voltage drops.

Equation (5) takes into account both the voltage drop errors due to current estimation errors and the voltage differencies caused by inaccurate data of network component impedances. Since, in radial systems, the latter one affects only the network voltages, but not the current distribution, the voltage estimation must not be strongly coupled with the current estimation.

The new estimated voltages are set as starting values for the next computation round of current estimation, when transforming the power measurements into current phasors. Hence the overall estimation process is iterative in nature, with a decomposition between current and voltage estimation.

An important phase of the state estimation process is also the filtering of the measurement data. For this the following checkings are made for the current/power measurements and for the voltage measurements respectively [5]:

$$\frac{\Delta I^2}{\sum \sigma^2_{meas,i} + \sum \sigma^2_{load,i}} \leq z^2 \qquad (6)$$

$$|\Delta U_{m,i}| \leq z\,\sigma_{Um,i} \qquad (7)$$

Where z is the number of deviation units, for instance, assuming Normal distribution and 99% probability, z = 2.32. $\sigma_{Um,i}$ is the deviation of the voltage measurement concerned. If a measurement does not meet the requirements of the above equations, it is cancelled. In the extreme case, where no measurements are available, the computation is made using load models only.

The powerful property of the estimation method desribed above is that it is able to adapt to the number of measurements available. In a practical case it is quite usual that some of the measurements are occasionally missing. On the other hand, the number of measurements is gradually increasing due to the more and more extensive application of distribution automation and associated information technology. The state estimation result is better the more measured information is used, and hence it is highly desirable that all the present and future measurements can be flexibly utilised in the state estimation applications.

3 MONITORING THE STATE OF NETWORK COMPONENTS

The central benefit of state estimation model is to make full utilisation of distribution system capacity possible. The ultimate limits for component loading can be defined as maximum rms currents and as maximum allowed temperatures of the insulation or conductor materials. Because of cyclic load behaviour and relatively slow thermal time constants, the biggest short time load allowed usually is well above the maximum continuous current rating.

In the state estimation application presented, the component currents and critical point temperatures are checked against the limit values at every computation round, i.e. once in a few seconds. The current limit values have been defined for switches, current transformers, lines and transformers. For the two last component groups also temperatures are monitored.

In the case of transformers, the hot-spot temperature calculation is based on the well established equations given in standards [6].

$$\theta_{hs}(t) = \Delta\theta_{to}(t) + \Delta\theta_{gr}(t) + \theta_a(t) \qquad (8)$$

Where $\Delta\theta_{to}$ is the temperature rise of top-oil over the ambient (θ_a) and $\Delta\theta_{gr}$ is the temperature gradient between hot-spot and top-oil. The first one is further obtained as follows:

$$\Delta\theta_{to}(t) = \Delta\theta_{to}(t_{-1}) + \left[\Delta\theta_{ir} - \Delta\theta_{to}(t_{-1})\right]\left[1 - e^{-\frac{t - t_{-1}}{\tau_o}}\right] \qquad (9)$$

Where τ_o is the oil thermal time constant and $\Delta\theta_{ir}$ is the final temperature rise in the case of a constant load current. Once the rated temperature rise $\Delta\theta_{or}$, the ratio between nominal loading and magnetizing losses P and the ratio between actual and nominal current K are known, the latter can be computed as follows:

$$\Delta\theta_{ir} = \Delta\theta_{or}\left[\frac{1+RK^2}{1+R}\right]^x \qquad (10)$$

The exponent x is a constant that depends on the transformer size, typical value being 0.8 for secondary transformers and 0.9 for primary transformers. The temperature rise of hot-spot over top-oil is computed using a similar equation as (9), but using the winding time constant instead. The steady state temperature rise is in this case computed as follows:

$$\Delta\theta_{gr} = Hg_r K^y \qquad (11)$$

Where Hg_r and y are constants given in the standard [6]. In the case of power cables, an equation similar to (9) is used to model the internal thermal response of the cable construction. The thermal resistances and thermal time constants can be calculated, once the cable geometry and the insulation material specific values are known [7]. The difficulty is the temperature rise in the installation environment, like in the soil. This varies with the installation type and soil properties, and actually also with seasonal factors like soil moisture content. In the case of directly buried underground cables, the temperature rise in soil is computed as follows:

$$\theta_e(t) = W_t\frac{\rho_s}{4\pi}\left[-Ei\left(-\frac{D_e^2}{16\delta t}\right)+Ei\left(-\frac{L^2}{\delta t}\right)\right] \qquad (12)$$

Where W_t is the total power dissipated in the cable [W/m], t is time [s], ρ_s is the soil thermal resistivity [Km/W], δ is thermal diffusivity [m^2/s], L is the depth of installation [m] and D_e is the cable outer diameter [m]. Ei is the exponential integral, defined as follows:

$$-Ei(-x) = \int_x^\infty \frac{e^{-v}}{v}dv \qquad (13)$$

In a practical case the limiting point for cable rating is in a location where several cables and possibly some other heat sources, like district heating pipes, are buried close to each other. In this case the mutual heating effects must be taken into account. This can be done using an equation similar to Eq. (12). For instance, the temperature rise θ_{pk} of cable p, caused by the adjacent cable k, is obtained as follows, Eq (14):

$$\theta_{pk}(t) = W_{Ik}\frac{\rho_s}{4\pi}\left[-Ei\left(-\frac{d_{pk}^2}{4\delta t}\right)+Ei\left(-\frac{d_{pk}^{'2}}{4\delta t}\right)\right]$$

Where W_{Ik} is the power lossed in cable k, d_{pk} is the distance between cables [m] and d'_{pk} is the distance between cable p and the thermal image of cable k [7].

When applying the above equations for transformer or cable hot-spot temperature computation, of high importance also is to know the variation of enviromental factors. In the case of power transformers, the ambient or top-oil measurements are utilised whenever available. In the case of underground cables it is strongly recommended to install temperature measurements at the cable surface in the critical locations, in order to track the variation of the soil thermal resistances. The importance of this kind of measurements is emphasized by the fact, that in most cases 50 to 70 % of the temperature rise is not in the cable itself but in the surrounding soil.

It is also important to know the accuracy of the state estimation system in the terms of expected load current statistical variation. The margin required for this strongly depends on the quality of load models and on the number of network measurements available. In the state estimation application presented, this problem has been mitigated by introducing two trigging levels. The lower one is an alarm, which is used when the statistical risk of overloading exceeds a certain given level. The higher level, trigging an emergency state, is met whenever a computed current or temperature exceeds the limit values given for the components. The margin between these levels depends on the degree of statistical variation and on the choise of the network owner on the risk level he wants to operate.

4 MONITORING THE VOLTAGE LEVELS

In addition to component loading, another limiting factor for network operation is the voltage drop in the distibution lines. It is the limiting factor especially in the rural and suburban networks with overhead lines. Traditionally the voltage drop has been monitored by computing the per cent voltage reduction in MV lines and by comparing the result to a fixed limit value. However, in practice the ultimate limit is dictated by the required voltage levels as received by the customers. According to the power quality standards [8], these should be maintained within the ±10% band around the nominal voltage.

In the state estimation system developed, the voltage levels are monitored using voltage density functions computed for the customer voltages. These functions are formed for the different levels of distribution system, i.e.: distribution area, primary substation area, secondary substation area. This kind of division makes it possible to locate the voltage level violations when ever they happen, and also makes it possible to design mitigation measures, like the control of primary substation on-load tap-changer to optimise the busbar voltage [9].

5 SUMMARY

A new state estimation technique for distribution systems was presented. The novelty compared to the previous techniques is that emphasis is put to the limiting technical factors. That is, not only the load flows and currents are estimated, but also the temperatures of the power system components are assessed and compared to the critical ones. The monitoring of voltage is based on the voltage received by the customers, which is compared to the accepted voltage levels given in power quality standards.

In the method, the estimation of branch currents and node voltages was decomposed. This arrangement is necessary, since the network impedance variation affects the node voltages but not the branch currents. The computation is optimised with speed so that practically a real-time application is possible. Also the utilisation of measurement is made dynamic so that it is possible to fully utilise all the measured information available.

Thanks to the state estimation system developed, it is possible to utilise the distribution capacity of the network into the full extent.

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