Monitoring and Operation of Transmission Corridors

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***Abstract*— Transmission corridors between interconnected power systems or within countrywide transmission systems are limiting network performance or even market activities. We describe a state-of-the-art wide-area measurement system which is commercially available, and a new method to assess the voltage stability of a transmission corridor. Using only topological information, several lines can be grouped into a so-called virtual transmission corridor, whose parameters can be calculated from wide-area measurements. A simple computational procedure for stability analysis, makes it possible to provide approximate stability margins with an update rate of less than a second. Such stability margins can be the basis for on-line dynamic rating of lines. Business cases for such dynamic rating are also discussed.**

I. Introduction

Nowadays network supervision systems are assuming a steady-state situation of the network, and all applications are therefore based on static models. The recent developments of phasor measurement units makes dynamic network supervision possible. The synchronization and high time-resultion of measurements allows the creation of dynamic snapshots of the situation in a wide area of a power system. This information can be used to update system models and act as online decision support or as basis for on-line, *dynamic*, rating of transmission lines. Commercial system providing these possibilities have recently become available. This gives the possibility of a wide range of stability monitoring and control applications. This paper focuses on the monitoring and operation of transmission corridors with the help of synchronized phasor information. We present a new and simple method to calculate the voltage stability margin for transmission corridors based on on-line phasor measurements. Since this method uses information about the actual operating conditions, the calculated voltage stability limit can be less conservative than those calculated using only off-line information. The method can therefore serve as basis for dynamic rating of lines which can be higher than the conservative off-line estimates that are today the operational practice.

The method is described in detail and illustrated by simulation of an actual power system which contains a transmission corridor. Furthermore economic analysis of the business cases arising from dynamic rating is presented.

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Fig. 1. Setup of wide area platform based on synchronized phasor measurements.

II. Monitoring System

The wide area platform for dynamic monitoring of transmission systems comprises of hardware:

- Phasor Measurement Units (PMU)
- Communication Links
- Central Unit (Personal Computer)

and software:

- Data preprocessing package
- Basic services
- Specific individual applications
- Graphical user interface (GUI)
- Package containing model/data of the supervised power system and coordination with other software packages

PMUs are placed in the substations to allow observation of a critical part of the supervised power system under any operation conditions (network islanding, outages of lines, generators etc.), taking into account a certain degree of redundancy to provide sufficient results also in a case of unavailability of some data (PMU outage, communication failure etc.). Measured data are sent via dedicated communication channels/links to a central unit, which is a central computational unit where the collected measurements are synchronized and sorted, yielding the snapshot of the power system state. This setup is shown in Fig. 1.

The snapshot is then processed by the Basic Services package (BS), which is part of the central unit. Basic Services denote the set of algorithms included in all installations of the wide area platform for different applications and they are comprising the following capabilities:

- ability to provide needed data for any application
- fast execution - leaving sufficient time for running applications within the sampling interval
- robustness - resistance against poor quality of some input data (unavailability, out of range, synchronization problems etc.)

Applications, which are attached to the output of BS, address various phenomena occurring in power systems, such as frequency instability, voltage instability etc. They predict the state of the power system and trigger appropriate actions if an incipient instability is detected. Their output as well as the output of BS are displayed to the power system operator by an ergonomic GUI. The functional structure described

Fig. 2. Functional architecture of wide area measurement platform based on synchronized phasor measurements.

Fig. 3. Laboratory setup of the wide area monitoring platform.

above is illustrated in Fig. 2. The voltage stability assessment method described in Sec. III is one example of a method that can be applied in such an algorithm. Other examples have been previously published [1–3]. The laboratory setup of the wide area platform for monitoring, protection and optimization comprises all the components of a field installation with the example of the supervision of a transmission line model. The setup is shown in Fig. 3.

III. Voltage Stability Monitoring for Transmission Corridors

Practical application of methods for detection of voltage instability are generally based solely on local measurements. The first methods were based on a local voltage measurement; if voltage becomes abnormally low (below a preset threshold value), voltage instability is assumed to be present and load is disconnected with a certain time-delay until voltage returns above the threshold value. This technique is normally referred to as Undervoltage Load Shedding (UFLS) and is still the most widely used technique to guard against voltage instability in high-voltage power networks [4]. The drawback of this method is that the voltage threshold must be set in advance, and thus the relay cannot adapt to changing operating conditions in the power system.

Other approaches are based on the estimation of a Thevenin equivalent of the network at a single bus. The current through a single line feeding that bus is used to estimate an equivalent Thevenin equivalent of a potentially complex network and the generation at the remote end. In this paper we refer to these as VIP-type approaches. Various variations on this theme have been presented by [5–7]. The drawback of these methods is that a single set of (local) measurements do not contain enough information to directly compute the parameters of the Thevenin equivalent, however these can in principle be estimated using a least-squares method once two or more sets of measurements are available. A necessary condition for accurate estimation of these parameters is that sufficient change in the measurements has occurred due to load change. During this time the feeding network and generation is assumed to remain constant. Therefore the estimation is noise-sensitive and introduces a time-delay comparable to that of standard SCADA systems (several minutes). Recent developments on this type of scheme [8] include also measurements at remote buses to assist in the estimation of the Thevenin equivalents. Although this paper does not in detail describe the estimation procedure applied, the simulations in the paper show a similar

Fig. 4. Illustration Thevenin equivalent estimation in VIP-type approaches.

Fig. 5. Illustration of the T- and Thevenin equivalents of the transmission corridor and generation in our approach.

time delay as those observed with the standard VIP-type approaches.

The main contribution in this paper is a method that uses measurements from both ends of the transmission corridor, enabling the splitting of the estimation part into two stages. Firstly, the parameters of a T-equivalent of the transmission corridor can be determined through direct calculation and therefore without the time delay seen in VIP-type approaches. Secondly a Thevenin equivalent of the feeding generators is computed. Once the parameters of the T- and Thevenin equivalents are known, stability analysis can be carried out analytically and various stability indicators calculated using the method described in Sec. III-C. The main advantage over the present state of the art is that parameters of the equivalent network can be computed from a single set of phasor measurements, and thus this method does not have the time delay of the VIP-type approaches. This benefit is achieved through the placement of additional phasor measurements.

A. Calculation of T- and Thevenin equivalents

The calculation of the Thevenin equivalent is carried out in two stages in order to benefit from the fact that we have measurements at both ends of the transmission corridor. First we calculate the parameters of a T-equivalent of the actual transmission corridor. Any load or generation that may be present in the transmission corridor as shown in Fig. 5. This load or generation is then implicitly included in the shunt impedance.

Applying Ohm's and Kirchoff's laws, with the known complex quantities (measured phasors) $\bar{v}_1$, $\bar{i}_1$ and $\bar{v}_2$, $\bar{i}_2$, we can calculate the complex impedances $\bar{Z}_T$, $\bar{Z}_{sh}$ and $\bar{Z}_L$ as follows

$$\bar{Z}_T = 2\frac{\bar{v}_1 - \bar{v}_2}{\bar{i}_1 - \bar{i}_2} \quad (1)$$

$$\bar{Z}_{sh} = \frac{\bar{v}_1\bar{i}_2 - \bar{v}_2\bar{i}_1}{\bar{i}_2^2 - \bar{i}_1^2} \quad (2)$$

$$\bar{Z}_L = \frac{\bar{v}_2}{-\bar{i}_2} \quad (3)$$

The complex voltage $\bar{E}_g$ and impedance of the equivalent voltage source $\bar{Z}_g$ cannot be simultaneously calculated in the same straightforward way, so one of them must be assumed to be known to avoid the time-delay of an estimation procedure similar to that in the VIP-type approaches. If the generators have voltage controllers and can be assumed to stay within their capability limits, $\bar{E}_g$ can assumed to be constant and $\bar{Z}_g$ could then be calculated using:

$$\bar{Z}_g = \frac{\bar{E}_g - \bar{v}_1}{\bar{i}_1} \quad (4)$$

However, in most practical cases it is more realistic to assume that $\bar{Z}_g$ is known since it typically comprises of the step-up

Fig. 6. Illustration of T- and Thevenin equivalents of transmission corridor and generation (a), and the reduction to a second Thevenin equivalent modeling the combined generation and transmission corridor (b).

Fig. 7. Example network diagram, showing a part of an actual customer network.

transformers and short transmission line to the beginning of the transmission corridor. It is therefore preferential to calculate the equivalent complex voltage of the generators as follows:

$$\bar{E}_g = \bar{v}_1 + \bar{Z}_g \bar{i}_1 \tag{5}$$

Once we have calculated the parameters of the T- and Thevenin equivalents, a second Thevenin equivalent for the combined generation and transmission corridor can be calculated as follows:

$$\bar{Z}_{th} = \frac{\bar{Z}_T}{2} + \frac{1}{\frac{1}{\bar{Z}_{sh}} + \frac{1}{\bar{Z}_T/2+\bar{Z}_g}} \tag{6}$$

and

$$\bar{E}_{th} = \bar{v}_2 \frac{\bar{Z}_{th} + \bar{Z}_L}{\bar{Z}_L} \tag{7}$$

Based on the second Thevenin equivalent in Fig. 6b, stability analysis can be performed analytically in a straightforward way. This process is described in the application example below.

B. Network Reduction

Consider the example network diagram in Fig. 7. To apply the estimation procedure, first the main load and generation centers must be identified. In this case, a distinct generation center can be found in the area north of Cut 1, which contain three major generators and some shunt compensation but only a few minor loads. Between Cuts 1 and 2 is an area with no generation equipment and only a few minor loads. This is the transmission corridor, whose stability is of interest. In the equivalencing procedure described above, the loads within the corridor will be implicitly included in the shunt impedance.

South of Cut 2 is an area with predominantly load character. There are some minor generators, but in cases where the voltage stability is endangered, these generators would have exceeded their capability limits and thus no longer contribute to stabilization. It is therefore reasonable to include them in the shunt impedance modelling the load.

After identifying the region boundaries, which are given by the two transfer cuts we can define two *virtual buses*, one for each end of the transmission corridor. These are the buses directly adjacent to a cut. Buses 6, 13 and 14 of the original system are grouped into virtual bus 1, and buses 24, 15 and 16 into virtual bus 2. The part of the system between cuts 1 and 2 becomes the *virtual transmission corridor*. At least one voltage in the area of each virtual bus and the currents on each line crossing a cut must be measured.

We can then compute the currents at either end of the virtual transmission corridor using

$$\bar{i}_i = \left(\frac{p_{cut-i} + jq_{cut-i}}{\bar{v}_i}\right)^* \quad i \in 1,2 \tag{8}$$

For example, here p_{cut-i} and q_{cut-i} refer to the sum of the power transfers through cut i, and $\bar{v}_i$ as the average of the voltages of the buses included in in virtual bus i.

C. Stability Analysis

This section outlines how the computed virtual transmission corridor model can be used to carry out computation of stability margins.

Based on the second Thevenin equivalent in Fig. 6, stability analysis can be performed analytically. The complex power delivered to the load impedance $\bar{Z}_L$ can be written

$$\bar{S}_L = \bar{Z}_L \left| \frac{\bar{E}_{th}}{\bar{Z}_{th} + \bar{Z}_L} \right|^2 \tag{9}$$

Assuming that load will evolve with constant power factor, we can set $\bar{Z}_L = k\bar{Z}_{L0}$, where k is a scale factor modeling change in the load impedance and $\bar{Z}_{L0}$ the present value of load impedance as calculated according to (3).

To find the point of maximum possible power transfer we need to compute the maximum of

$$p_L = \Re\left[\bar{S}_L\right] = \Re\left[k\bar{Z}_{L0} \left| \frac{\bar{E}_{th}}{\bar{Z}_{th} + k\bar{Z}_{L0}} \right|^2\right] \tag{10}$$

with respect to the load impedance scale factor k. Differentiating (10) and solving for the first and second order conditions we find that the critical load scale factor, where no further increase in p_L is possible, is given by

$$k_{crit} = \left| \frac{\bar{Z}_{th}}{\bar{Z}_{L0}} \right| \tag{11}$$

After insertion of $k = k_{crit}$, (10) becomes

$$p_{Lmax} = \Re\left[k_{crit}\bar{Z}_{L0} \left| \frac{\bar{E}_{th}}{\bar{Z}_{th} + (k_{crit}\bar{Z}_{L0})} \right|^2\right] \tag{12}$$

Extensive field measurements reported by [9] have shown that normally at least part of the load has constant power characteristics, and the point of maximum power transfer as given by (12) then also becomes a loadability limit. Past this limit there is a loss of equilibrium and voltage collapse will occur [10, pp. 29]. Eq. (12) therefore also becomes a stability limit.

The voltage $\bar{v}_2$ at the virtual load bus is given by

$$\bar{v}_2 = \bar{E}_{th} \frac{k\bar{Z}_{L0}}{\bar{Z}_{th} + k\bar{Z}_{L0}} \tag{13}$$

Based on (11)-(13), various stability margins can be defined as follows; In terms of load impedance (in percent)

$$MARGIN_Z = 100(1 - k_{crit}) \tag{14}$$

Fig. 8. The estimated Thevenin voltage and impedance, load impedance and power margins during the disturbance scenario.

Fig. 9. PV-curves at four different instants during the collapse scenario. The distance between the current operating point (marked by the asterisk) and the rightmost point of each curve indicates the stability margin.

in terms of active power delivered to the load bus (in p.u.)

$$MARGIN_P = \begin{cases} p_{Lmax} - p_L & \text{if } \bar{Z}_L > \bar{Z}_{th} \\ 0 & \text{if } \bar{Z}_L < \bar{Z}_{th} \end{cases} \quad (15)$$

For example, if the value calculated by (15) is 4 p.u., voltage instability will occur if the active power load increase is larger than 4 p.u.

Fig. 8 shows simulation results where the the two lines between buses 9 and 16 are tripped at 20 s and at 30 s, which makes the system voltage unstable, and eventually there is a collapse at about 190 s. In the simulation, we have used a load model with an instantaneous impedance characteristic which recovers to constant power with a time constant of 60 s.

The top-left figure shows the calculated voltages of the two virtual buses, and the top right figure shows the estimated load and Thevenin impedances. The two sharp step increases in the Thevenin impedance are due to the line trippings and the decrease in the load impedance is due to load recovery dynamics. In this case, the stability boundary is crossed at about 170 s, as indicated by the crossing of the two curves, and the collapse of the system progresses rapidly after this point. The bottom left figure shows the power margin. Note the two sharp steps in the power margin which are due to the two line trippings. The estimated Thevenin voltage is shown in the bottom right plot.

Fig. 9 shows the so-called PV-curves at four different instants. Before the disturbance, at 19.8 s, the power transfer is about 14 p.u. compared to the maximum 22 p.u., as given by the rightmost point of the PV-curve. At time 39.8 s, the fast transients following the two line trippings have settled and we can see that the maximum transfer is now about 13.5 p.u. Because of the initial load relief provided by the initial impedance characteristic the load power has dropped to about 12.6 p.u. however the constant power characteristic of the load drives the operating point towards the transfer limit and eventually the stability boundary is crossed at 170 s. Note that if we consider that the load in the long-term has constant power characteristics known, the instability could be detected directly following the line trippings (since the pre-fault loading was larger than the post-fault transfer limit).

IV. Business Cases for Increasing Transmission Capacity

An energy market with fewer limitations is profitable for the end users because of lower prices and also for a couple of generation companies offering cheap production. Despite of the users interests, the investments in the network to relieve congestions are up to the transmission owners or TSOs. The

Fig. 10. Power flow demand P_d for typical days.

Fig. 11. Cumulative frequency distribution (CFD) of power flow demand P_d as percentage of time considering uncertainty of demand curves (average, lower and upper boundary.

incentives for these investments are coming from the market via ISO or TSO through different channels such as market splitting or auctioning. Two typical cases for the investment in increasing the transmission capacity are discussed in the following. The first one is a hardware upgrade either with an additional control or compensation device or with line re-rating, both to increase the transmission capacity stepwise with nearly 100 % availability of the additional capacity. The second case deals with the investment in dynamic rating methods. The availability of the additional usable transmission capability has then a specific probability distribution, which is considered with an uncertainty calculation. In both cases the market environment is modelled with probabilistic methods as well and calculated with a Monte-Carlo-Simulation.

A. *Re-rating or new control device*

For the following calculation a congested 400-kV-double-line is assumed. The transmission system is operated in a conservative way, which means, that the NTC values caclulated offline for this line are used for the operation. The double line has a rated capacity of 1200 MW. Due to N-1 calculations only half of this is to be used (600 MW). The reliability margin (TRM) is 100 MW. Therefore the NTC value is P_{NTC} = 500 MW which is available for market activities.

For the modelling of the energy market 12 typical days within a year are taken showing the power flow, which is determined from unconstraint trading. Fig. 10 is showing exemplarily typical power flow demands for two days of the year. To model the uncertainty within the interval each of these daily curves is representing a rectangular distribution between +/- 10 %. This also includes the variations between the years of the calculation period.

The cumulative frequency distribution of the power flow demand over the line is shown in Fig. 11.

The TSO/ISO is handling the non-permanent congestion with redispatch. The next step is the modelling of the expected redispatch costs C_r. It can be assumed, that the redispatch costs are marginal costs, which are close to the market clearing prices. The marginal costs for clearing the congestion are modelled as a triangular distribution between C_m = 15 and 25 Euro/MWh. (Triangular Distribution instead of Gaussian Distribution is chosen because of fixed interval boundaries).

Installed additional capacity ΔP_{inst}, can reduce the congested power flow demand ΔP_c up to the value of ΔP_{inst}. This allows operating the congested line above the NTC value P_{NTC}. The redispatch costs ΔC_r are saved. This cost savings can be calculated as the additional energy, which can be transmitted times the marginal price according to the following

Fig. 12. Probability distribution of ΔC_{rp} being below a certain value for an additional installed capacity of ΔP_{inst} = 20 MW

Fig. 13. Probability curves of present value of redispatch costs ΔC_{rp} for different values of installed transmission capacity ΔP_{inst}

equations (16) and (17).

$$\Delta C_r = C_m \sum_{i=1}^{12} \sum_{j=1}^{24} \min(\Delta P_c, \Delta P_{inst}) \frac{365}{12} \cdot 1h \qquad (16)$$

$$\Delta P_c = \begin{cases} P_d - P_{NTC} & \text{if } P_d - P_{NTC} > 0 \\ 0 & \text{if } P_d - P_{NTC} \leq 0 \end{cases} \qquad (17)$$

All the modelled uncertainties are implemented within a Monte Carlo Simulation to judge about the worth of an investment. With an assumed payback time for the investment of 5 years and a depreciation rate of 7 % the present value of the redispatch costs ΔC_{rp} is calculated. Fig. 12 shows the probability distribution for the redispatch costs to be below a certain value.

This calculation is dependent on the additional installed transmission capacity ΔP_{inst}. Fig. 13 shows for installations of additional 20 to 100 MW the present value of the redispatch costs for the probabilities 10, 50 and 90 %.

It can be seen, that with growing additional installed capacity the probable earnings from the redispatch are running into maximum values. In all these cases the earnings from the investments are relatively low due to non-permanent resp. rare congestion cases. Therefore and alternative investment case using dynamic rating instead of an hardware installation is introduced in Sec. IV-B.

If the market would demand for in average 100 MW more transmission capacity, the line would be more often congested. The probability distribution for this case is shown in Fig. 14. In this case an investment up to 8.0 Mio. Euro has a probability of 100 % for the payback within 5 years under the assumed conditions.

B. Dynamic Rating

This second business case is based on the same assumptions leading to Fig. 11 for the transmission capacity demand. Instead of investing in additional hardware for a 100 % available shift of the NTC, dynamic rating methods shall be evaluated. Dynamic rating in this sense means online ratings that are based on actual line parameters. This is for example thermal rating but as well for voltage stability like described in the first part of this paper. Due to the fact that the actual power margin of a line depends on the actual parameters, which in turn are dependent for example on weather conditions, the additional margin is not continuously available.

Fig. 14. Probability distribution of ΔC_{rp} being below a certain value for an additional installed capacity of ΔP_{inst} = 20 MW based on an higher average demand of 100 MW.

Fig. 15. Availability distribution of additional usable transmission capability ΔP_{dyn} determined by dynamic rating methods with varying security margins.

Fig. 16. Probabilities of present value of redispatch costs ΔC_{rp} for different security margins of dynamic rating methods $\Delta P_{dyn,50}$.

Using dynamic rating the availability of the additional transmission capacity ΔP_{dyn} is between zero and one. Figure 8 shows the exponentially modelled cumulative frequency distribution. The basic curve with $\Delta P_{dyn,50}$ = 300 MW is adapted from sag measurements for thermal ratings. Similar distributions can be expected for dynamic voltage stability ratings. $\Delta P_{dyn,50}$ means the used exponent for the exponential distribution. To have a certain distance to the measured maximum rating, several curves with lower values are shown. These curves can be used instead of the maximum curve considering uncertainties in the determination of the maximum rating values. Simpler methods like the PMU based approach in comparison to the direct sag measurement need additional security margins. The curves result in values around or below the $\Delta P_{dyn,50}$ = 50 MW curve.

The business calculation is prepared with the availability distribution of the additional available transmission capacity from Fig. 15.

Even if the security margin is high (curves with $\Delta P_{dyn,50}$ = 10 or 20 MW) there is a noticeable probability of earning. The relatively low investments in these measurement technologies compared to re-rating are providing reasonable earnings, even if the 10 % probability is very low and the evaluated case has very rare congestions

C. Discussion of Business Cases

The models for the business cases have two stages. The first one is the calculation of the costs, which can be saved, or the earnings that can be achieved by increasing the usable transmission capability. This determination has a lot of uncertainties, which have to be taken into account. The above modelled redispatch is appropriate and applied, if the congestion of a line is not permanent. The modelling of market splitting or auctions can be done in an almost similar way.

The second stage of modelling is the method for relieving the congestion. Whereas an investment in a controllable device or in re-rating is available more or less all the time, other methods like dynamic rating, monitoring or wide area protection have to be modelled with uncertainties as well. This is exemplarily shown for dynamic rating technologies.

The high availability of re-rating leads to more save earnings and therefore to higher possible investments. However, due to the high component costs the congestion must be frequent or almost permanent. Cheaper and more cost-effective alternatives when congestion is rare are dynamic rating methods. The earnings are due to several probabilities in the model less save than for re-rating methods.

V. Future Work

Referring to the method described in Sec. III, the estimated Thevenin equivalent of the network is now used only to assess the stability of the power system. The information in Fig. 9 will be presented online to the operator and thereby visualize the degree of stability to the operators. However, collapse scenarios may evolve too quickly for the operator to respond. The immediate continuation of theoretical work will be to extend the method with so it can calculate automatic corrective control actions when instability is detected. Another issue is the accuracy of the power margin that is calculated. Since the method internally uses a reduced representation of the power system, the power margin computed is an approximation. The initial results based on the power system in Fig. 7 indicate that the approximation is good and that the method is accurate, but future work is necessary to validate the method also on other network topologies.

A pilot installation of the wide-area platform in a European power system is now completed and the performance is continuously monitored. The implementation of the voltage stability assessment method is also part of the future work.

VI. Conclusions

A commercially available platform for wide-area monitoring and control based on phasor measurements has been described. A new method for the voltage stability assessment of transmission corridors has been described. Using measurements at either end of the transmission corridor, a reduced equivalent of the network can be constructed and used for analytical stability assessment. The result of the stability is displayed using a dynamically updated PV-curve and numerical stability margins. This information can be used to provide accurate dynamic rating of lines, since it is based on information about the actual operating conditions. In the second part of the paper, the economic benefit of such dynamic rating is quantified and is shown to be more easily economically justifiable than the addition of new lines, especially when congestion is present intermittently on a transmission corridor.

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