Europejski Instytut Miedzi
Copper Alliance

Leonardo ENERGY

Inteligentne sieci (Smart Grid)

Praktyczne doświadczenia pracy liniowego estymatora stanu opartego na urządzeniach PMU w sieci dystrybucyjnej

M. Richter, M. Wolter

Otto-von-Guericke-University, Magdeburg, Germany

A. Naumann, P. Komarnicki

Fraunhofer Institute IFF, Magdeburg, Germany

Nr ref EIM: EIM030240

Abstract

This paper presents the system design and the first practical experiences of a Distribution Area Monitoring System (DAMS) that was practically applied in the German 110 kV network. With regard to the involved components of the larger ICT system, the software architecture – including standardized Smart Grid communication protocols and interfaces – is described. As a main component, a linear state estimator is presented, that uses only phasor measurements to calculate the complex-valued node voltages. Real measurement data provides the necessary input for observing the typical characteristics in distribution systems and for analyzing accuracy and plausibility of the results. A consecutive state assessment is applied in order detect violations of permissible operation limits.

Introduction

A study by the German Energy Agency (DENA) identified a high demand on ancillary system services provided by distributed energy resources (DER) in the future [1]. In particular local voltage support by reactive (and indirectly by active) power adjustments as well as provision of (synthetic) spinning reserve are the main issues. Since most of the larger DER are installed in the 110 kV level and subordinate networks, the influences of this highly volatile generation technology will primary show its stability impacts there. As a result, more responsibilities concerning necessary ancillary service contributions are expected to be shifted from the TSO towards the DSO.

Since the active real-time coordination of DER providing ancillary services in the distribution grid requires exact information about the actual state, the quality of conventional SCADA is no longer high enough. On the one hand, it needs to be supplemented by high-accuracy measurement devices utilizing synchrophasor technology [2], and on the other hand, new data standards and data transmission interfaces need to be implemented in order to unify communication requirements and to improve the interoperability between the increasing numbers of DER and the operators.

The realization of a system for real-time monitoring and control of DER in the 110 kV level is the essential target of the project SECVER [3], funded by the German Federal Ministry for Economic Affairs and Energy. In this context, a region in Germany was chosen that has a high amount of renewable energy production in comparison to its average consumption. With an installed wind power capacity of 160 MW and an installed photovoltaic capacity of about 40 MW facing an overall peak load of 220 MW the considered region is characterized by many energy export situations during the year. As one part of the project, this paper focuses on the distribution area monitoring system (DAMS) and its configuration for practical use in the German 110 kV power grid.

System design

Components

The DAMS is part of a larger system that consists of several other components, whose interaction allows for the completion of the desired task. The main components are:

1) Distribution Area Monitoring System (DAMS)
   The DAMS performs the task of calculating the state vector of the system through optimally processing the provided system and measurement data. Subsequently, an assessment of the system state is possible, e.g. detecting line current and node voltage violations.
2) Distribution Area Control System (DACS)
   Using the calculated system state provided by the DAMS, the main task of the DACS is to perform an optimization of the power system. Through the determination and the transmission of new active and reactive power set points for the integrated DER a stable operation of the power system shall be ensured.
3) Measurement and Control Devices
   For measurement and control purposes phasor measurement units (PMU) are used to provide high accuracy measurement data from the field while remote terminal units (RTU) are used to transmit the set point values to the process level of each power unit.

Measurement of power system parameters

Regarding the acquisition of power system parameters, PMUs are used to provide high precision voltage and current measurements tagged with a time stamp several times per second [2]. Since they deliver a phasor as output, measured values from different nodes in the network can be compared directly.

To achieve full observability a sufficient number of topological network nodes need to be monitored. This was the main target when the placement of PMU devices in the considered 110 kV region was performed. Additionally, technical limitations, e.g. accessibility of nodes and limited number of PMU input channels, as well as legal requirements like the protection of DSO customer data, were taken into account.

Control of power unit set points

In order to perform a control of the DER, set points are transmitted from the DACS to the RTUs, which serve as a gateway between the proprietary process level of the individual unit and the described optimization system. The RTUs provide a generic interface for setting control values and acquiring measurement data. Additionally, they need to make sure that a safe and reliable connection between the control system and the RTU is guaranteed. For the use in project SECVER the RTUs are configured in such a way, that they are able to set control values for active and reactive power while continuously providing measurement values for voltage, current, active and reactive power.

Information and communication architecture

In order to fulfill the requirements of the system and ensure a reliable and safe operation, an appropriate architecture for information and communication usage is necessary. The basic structure of this architecture including the described main components is shown in Fig. 1.

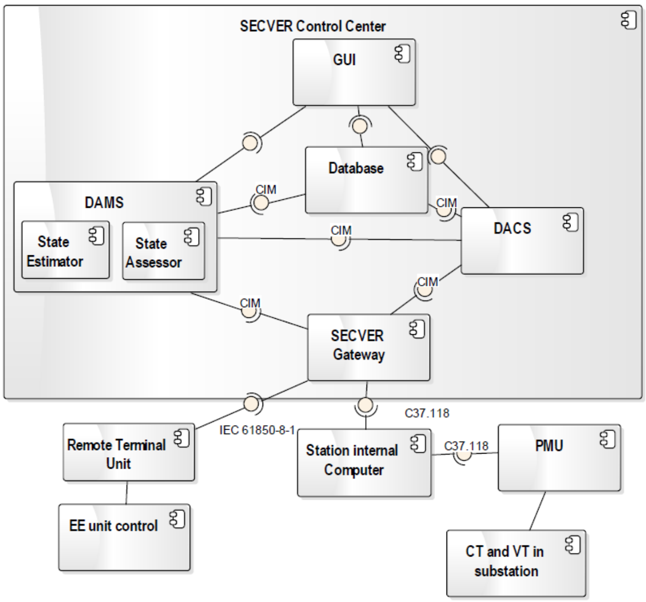

Fig. 1: ICT concept

All necessary data for the calculation is provided by the database and the measurement devices in the field. The communication of all the components inside the SECVER control center relies on the common information model (CIM) according to IEC 61970 [4] and IEC 61968 [5]. Not all data according to this standard is necessary for the purposes of the system, so a reduced data model was developed. Additionally, an appropriate SECVER data exchange profile for distribution network operation was defined.

The communication between the control center and the field devices is done in two ways. For data exchange between the control center and the PMUs the IEEE C37.118 [6] standard is applied. The received measurement data is converted to a CIM conform data format in the SECVER gateway. A similar conversion is also realized for the RTUs, while here data exchange takes place in both directions, since RTUs transmit measurement values to the control center and control values to the connected power units. The RTU communication is realized according to IEC 61850 [7], using the underlying MMS protocol [8] in connection with IEC 61850-8-1 [9].

To make sure the communication is safe and reliable, suitable measures are taken to ensure a robust communication link. These measures are described in the IEC 62351 series [10] and their application is described in [11].

Linear state estimation

The state estimation aims on the accurate determination of the system's state vector x [12], either in terms of voltage magnitude and angle or expressed as complex value containing real and imaginary part respectively, see (1).

$$\underline{\boldsymbol{X}}^T = [\underline{v}_1 \ \dots \ \underline{v}_n] \tag{1}$$

Where $\underline{v}_i$ is the complex voltage of node *i*.

Due to a better performance in MATLAB®/SIMULINK the second option was chosen for calculations, though PMU devices usually provide data in polar coordinates. Since measurement data is exclusively based on PMU, the state estimation approach results in a linear equation system shown in (2).

$$\underline{\boldsymbol{z}} = \underline{\boldsymbol{H}\boldsymbol{x}} + \underline{\boldsymbol{\varepsilon}} \tag{2}$$

Where $\underline{\boldsymbol{z}}$ is the measurement vector, $\underline{\boldsymbol{H}}$ is the measurement matrix describing the mathematical relation to $\underline{\boldsymbol{x}}$ and $\underline{\boldsymbol{\varepsilon}}$ contains the individual errors due to measurement uncertainties.

Using PMU measurements there are only three different types that need to be distinguished for setting up the measurement matrix $\underline{\boldsymbol{H}}$:

1. PMU voltage measurements
2. PMU line current measurements
3. PMU load current measurements

The general state estimation approach can then be formulated more precisely in (3).

$$\begin{bmatrix} \underline{\boldsymbol{v}}_{\text{PMU}} \\ \underline{\boldsymbol{i}}_{\text{PMU,Line}} \\ \underline{\boldsymbol{i}}_{\text{PMU,Load}} \end{bmatrix} = \begin{bmatrix} \underline{\boldsymbol{H}}_1 \\ \underline{\boldsymbol{H}}_2 \\ \underline{\boldsymbol{H}}_3 \end{bmatrix} \cdot \underline{\boldsymbol{x}} + \begin{bmatrix} \underline{\boldsymbol{\varepsilon}}_1 \\ \underline{\boldsymbol{\varepsilon}}_2 \\ \underline{\boldsymbol{\varepsilon}}_3 \end{bmatrix} \tag{3}$$

Since PMU voltage measurements directly acquire the wanted value $\underline{x}_j$, respective elements in $\underline{\boldsymbol{H}}_1$ can be set to 1. The individual relation between the current measurements and the complex node voltage values described by $\underline{\boldsymbol{H}}_2$ and $\underline{\boldsymbol{H}}_3$ can be derived using the pi equivalent circuit for network branches shown in Fig. 2. Accordingly, (4) describes the associated mathematical dependencies.

$$\begin{bmatrix} \underline{i}_{ij} \\ \underline{i}_{ji} \end{bmatrix} = \begin{bmatrix} \underline{y}_{l,ij} + \underline{y}_{s,ij} & -\underline{y}_{l,ij} \\ -\underline{y}_{l,ij} & \underline{y}_{l,ij} + \underline{y}_{s,ij} \end{bmatrix} \cdot \begin{bmatrix} \underline{v}_i \\ \underline{v}_j \end{bmatrix} \tag{4}$$

A suitable solution of (2) or (3) respectively can only be achieved, if the equation system is at least exactly defined. Depending on the available number of measurement values, over-defined relations can be addressed by using the Weighted Least Squares (WLS) algorithm [13]. Here, the residual deviations between the measurements in $\underline{\boldsymbol{z}}$ and $\underline{\boldsymbol{H}} \cdot \underline{\boldsymbol{x}}$ are minimized.

Phasor measurements in distribution

A real German 110 kV distribution grid was used for practical phasor measurement implementation. Fig. 3 shows the original network topology (left) and indicates PMU installations by voltage and current measurement points. In this configuration full observability according to [14] could be provided by the exclusive use of PMU. In contrast to other investigations, multi-area decomposition as described in [15] and the use of non-synchronized measurements addressed [16] were not necessary.

Data acquisition

All necessary network information covering the grid's actual topology based on the switch positions in the substations, the line equivalent circuit values and the local assignment of measurements can be queried from a central data base system. Additionally, the SECVER gateway (see Fig. 1) is responsible for gathering all information of the installed PMU online. By preselecting consistent measurement sets with an identic time stamp, it provides the input data for the DAMS.

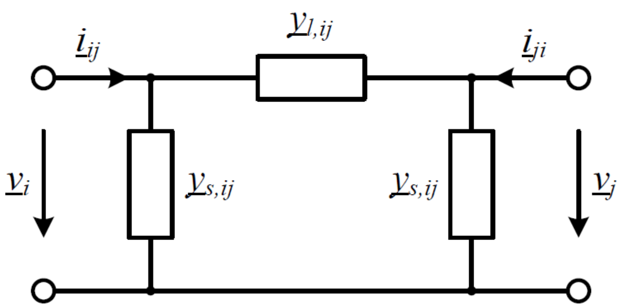

Fig. 2: Pi equivalent circuit

First test measurements in the field revealed a high degree of unbalance. Single-phase considerations would subsequently lead to inaccurate power system calculations. Since most of the industrial phasor measurement units already support symmetrical components transformation, the use of positive, negative and zero sequence system values seems to be the most expedient solution. Tab. 1, 2 and 3 show the synchronized raw measurement data of the positive sequence system transmitted to the DAMS (with identical time stamps of all values).

Table 1: PMU node voltage measurements

Node number	**Magnitude of positive sequence voltage in kV**	**Phase angle of positive sequence voltage in °**
2	67,22	-94,81
3	67,19	-94,87
4	67,21	-95,73
5	67,29	-95,81
6	67,23	-95,78
7	67,24	-95,97
9	66,55	-95,89
10	66,89	-95,84
11	66,99	-95,98
12	66,96	-95,97

Table 2: PMU line current measurements

From node number	To node number	Magnitude of positive sequence current in A	Phase angle of positive sequence current in °
4	1	59,84	87,89
5	16	24,02	-21,54
6	8	107,36	90,82
7	17	19,42	25,65
11	14	108,70	-111,71
12	13	39,41	-116,67

Table 3: PMU load current measurements

Node number	Magnitude of positive sequence current in A	Phase angle positive sequence current in °
2	73,76	-98,14
3	74,22	-101,58

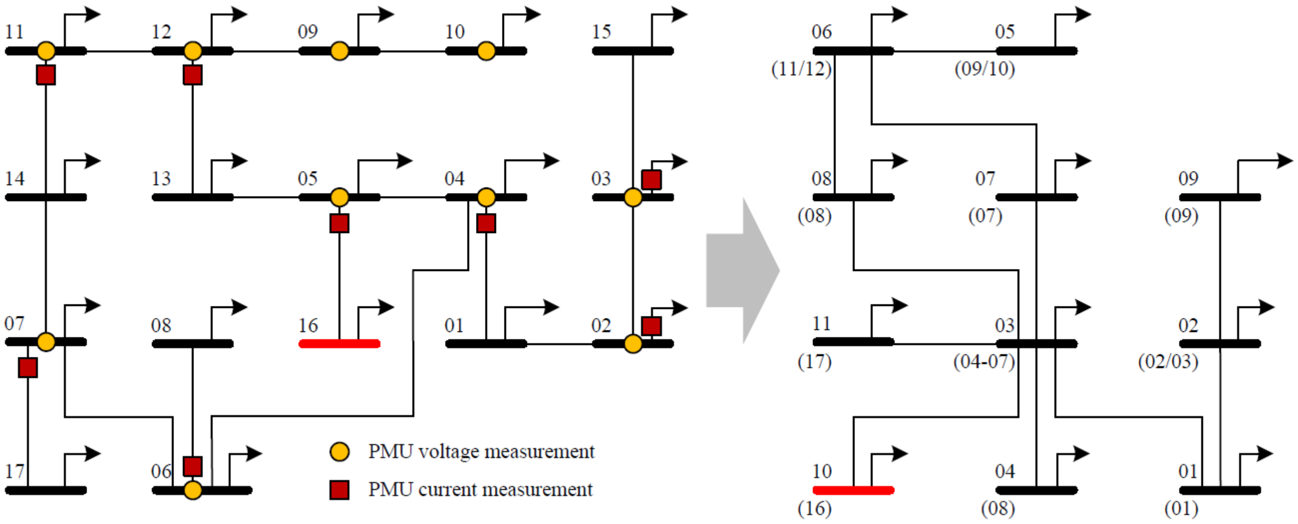

Fig. 3: 110 kV distribution network topology with PMU measurements (left) and minimized network (right)

Processing

As the voltage measurements in Tab. 1 already indicated, a low magnitude and angle difference between the nodes can be observed. This typical characteristic of distribution grids was also confirmed by the results of the linear state estimation. Together with the limited accuracy of both the line model and the PMU measurements this has negative impact on subsequent power flow calculations that aim on assessment studies. Therefore, it is suggested to summarize nodes of the same station and to assign averaged values for voltage magnitude and angle. The resulting minimized network structure is illustrated on the right side of Fig. 3, where the nodes have been given new numbers. Brackets indicate the summarized nodes from the original system.

For further considerations, all data is transformed to per-unit values, where the base voltage is 110 kV and the base power is 100 MVA. In addition, all angle differences were referenced to node 10 (16), because it also served as the slack node for load flow calculations.

The mean values describing the individual node voltage phasors of the transformed structure can be viewed in Fig. 4. Provided that the state vector is complete, (4) and (5) can then be applied to get information regarding the line current and the load power at the nodes.

$$\underline{s}_i = \underline{v}_i \cdot \left(\sum_{j=1}^{n} \underline{y}_{ij} \underline{v}_j \right)^* \quad (5)$$

Information regarding active and reactive power demand is given in Fig. 5. Fig. 6 shows the individual line current of the branches relative to its maximum thermal line current. Those calculations are necessary for subsequent load flow studies and power system sensitivity analysis.

Analysis and assessment

The aim of the system state assessment is to detect violations of grid parameter limits according to [17] and transgressions of rated asset data. In this context, the quitting of permissible voltage ranges and the exceedance of maximum thermal line currents are the most severe indicators of the existence of critical situations that the DACS would have to eliminate in the following step (see section II.A.2).

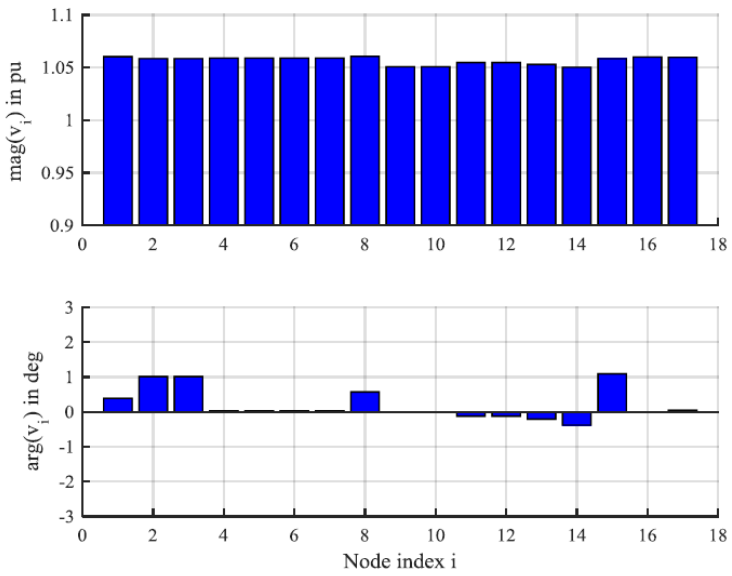

Fig. 4: Node voltage magnitude and angle

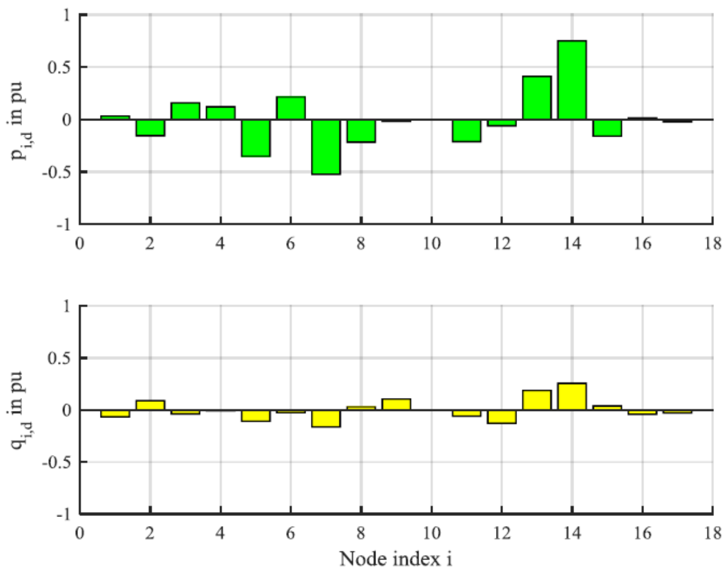

Fig. 5: Active and reactive power demand

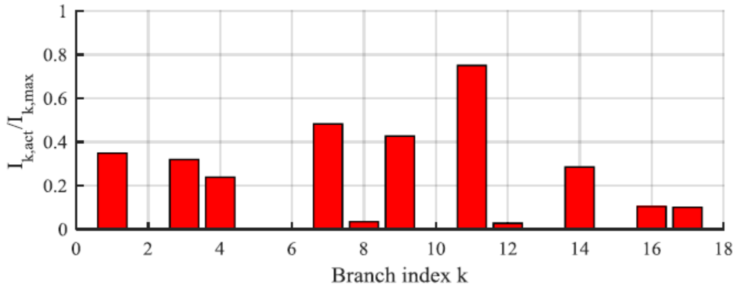

Fig. 6: Line current utilization

The state vector as a result of the used measurement set shows a slightly increased voltage magnitude at all nodes (Fig. 4). A possible cause is a high power feed-in coming from strong wind and photovoltaic penetration. Negative values for active and reactive power in Fig. 5 support this assumption.

Fig. 6 indicates the utilization of the lines. Taking into account the (n-1) criteria, branch number 11 could endanger a secure operation of the distribution grid, because the value exceeds 60 % of the permissible limit.

Initiating countermeasures

In order to fix the occurring disturbances, the DACS provides necessary functions covering congestion management and voltage stability analysis. New values for active and reactive power of controllable DER received from online calculations as well as a reliable ICT infrastructure allow for the fast adaption of operating points. First practical experiences have been made in a radial 20 kV network in [18]. Closer descriptions of the DACS shall not be part of this paper and will be addressed in other publications.

Summary and conclusions

This paper described the practical experiences of handling PMU values in a 110 kV distribution grid as part of a Distribution Area Monitoring System. Real measurement values based on the exclusive use of PMU data have been analyzed in order to validate the function and the performance of a linear state estimation approach.

The major advantage compared to conventional state estimation is the linear relation resulting from the application of PMU. No iterative method for solving non-linear equations is necessary, since the measurement matrix H does not depend on the system state. Consequently, a higher performance can be achieved, that creates the preconditions for consecutive online investigations and for handling big data in the future.

Regarding the measurement values, typical characteristics of distribution networks could be observed more accurately. An important challenge that has been revealed is how to handle small angle differences in connection to the limited accuracy of phasor measurements. Though PMU provide a much better quality than non-synchronized measurements their application in distribution grid requires stringent conditions. A solution approach that has been presented is the summing-up of bus bar sections belonging to one and the same substation. Indeed, individual PMU errors can be compensated, but the minimized network does not represent the original behavior in its entirety. Further investigations need to address that more extensively.

Eventually, it was proven, that DSO can benefit from the use of synchronized phasor measurements and their improved capabilities regarding computation time, reliability and accuracy. Thus, an intelligent placement as well as the use of a smart grid suitable communication infrastructure establish the basis for medium-term observation and control challenges in the distribution grid.

Acknowledgement

This paper was developed as part of the research program SECVER funded by the German Federal Ministry for Economic Affairs and Energy.

References

[1] Deutsche Energie-Agentur (dena), „dena-Studie Systemdienstleistungen 2030. Sicherheit und Zuverlässigkeit einer Stromversorgung mit hohem Anteil erneuerbarer Energien," Berlin, Germany, 2014

[2] G. Phadke, J. S. Thorp, *Synchronized Phasor Measurements and Their Applications*, Springer Verlag, 2008

[3] SECVER Project, [Online]. Available: http://www.secver.de

[4] *Energy management system application program interface (EMS-API) - Part 1: Guidelines and general requirements*, IEC 61970-1 ed1.0, Dec 2005

[5] *Application integration at electric utilities - System interfaces for distribution management - Part 1: Interface architecture and general recommendations*, IEC 61968-1 ed2.0, Oct 2012

[6] *IEEE Standard for Synchrophasor Measurements for Power Systems*, IEEE Std. C37.118.1-2011, Dec. 2011

[7] *Communication networks and systems for power utility automation - Part 1: Introduction and overview*, IEC/TR 61850-1 ed2.0, Mar. 2013

[8] *Industrial automation systems - Manufacturing Message Specification - Part 1: Service* definition, ISO 9506-1:2003, 2003

[9] *Communication networks and systems for power utility automation - Part 8-1: Specific communication service mapping (SCSM) – Mappings to MMS (ISO 9506-1 and ISO 9506-2) and to ISO/IEC 8802-3*, IEC 61850-8-1 ed2.0, Jun. 2011

[10] *Power systems management and associated information exchange - Data and communications security - Part 1: Communication network and system security - Introduction to security issues*, IEC/TS 62351-1 ed1.0, May 2007

[11] Naumann, P. Komarnicki, Z. Styczynski, "Using the IEC 61850 protocol for safe and reliable information exchange in smart grid power systems," *9th International Conference on Critical Information Infrastructures Security*, Limmasol, Cyprus, Oct. 2014

[12] E. Handschin, *Elektrische Energieübertragungssysteme*, Lüthig Verlag, Heidelberg, Germany, pp. 157-177, 1991.

[13] S. Chakrabarti, E. Kyriakides, „PMU Measurement Uncertainty Considerations in WLS State Estimation," *IEEE Trans. on Power Systems*, Vol. 24, No. 2, pp 1062-1071, 2009

[14] R. F. Nuqui, A. G. Phadke, "Phasor Measurement Unit Placement Techniques for Complete and Incomplete Observability," *IEEE Trans. on Power Delivery*, Vol. 20, No. 4, Oct. 2005

[15] X. Yang, X.-P. Zhang, S. Zhou, "Coordinated algorithms for distributed state estimation with synchronized phasor measurements," *Applied Energy*, Vol. 96, pp. 253-260, 2012

[16] M. Powalko, K. Rudion, "Improving power system state estimation with PMU," *54th IWK International Scientific Colloquium*, Ilmenau, Germany, 2009

[17] Verband der Netzbetreiber e.V., "DistributionCode 2007 – Regeln für den Zugang zu Verteilungsnetzen," Germany, Aug. 2007

[18] ReStabil Project, funded by the Ministry of Agriculture and Environment, Saxony Anhalt, Germany, 2014-2015