ENG63 GridSens

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1 Executive Summary

Introduction

As electricity networks evolve to accept more distributed renewable energy generation, it is vital that sufficient information about current, voltage and frequency exists to manage and control them; enabling grid stability and reducing the possibility of blackouts. Observation and control of electrical grids relies on a network of sensors so that the status of the network is constantly monitored, known as 'state estimation'. The majority of research into controlling networks relies on knowledge about the structure of the network combined with modelling, or simulation, of the network. However, in practice the topology and impedances, or resistance to AC current, of distribution networks are often poorly documented due to inaccurate network circuit diagrams, uncertain connections or missing information. This project developed techniques to enhance the capabilities of sensor networks, to estimate missing information and to validate new algorithms for optimal sensor placement. The results were then demonstrated on real networks, and shown to improve the monitoring and knowledge of electrical distribution grids to improve security and reliability.

The Problem

As electricity networks become more complex with distributed renewable generation and two way flows (i.e. consumers using electricity as well as putting it back into the grid), it is vital that sufficient information exists for their management and control. The precise structure and topology of distribution grids are often not known; however this information is required if retrofitted distributed renewable generation is to be installed and used reliably, whilst maintaining a stable and controllable network.

In order to promote a pan-European electricity network, the sensor network metrology must meet the requirements of the diverse range of distribution networks in place throughout Europe and support the design of new standard European smart grids, which can manage the two way flow of current, the billing requirements and network control.

The Solution

The overall aim of this project is therefore to develop techniques to enhance the capabilities of sensor networks to improve the monitoring and knowledge of electrical distribution grids. Algorithms were designed to take into account all possible data sources to minimise the cost and amount of instrumentation required to give the most accurate estimate of power flow throughout the grid.

Impact

The project is enabling a lower cost, low-carbon electricity network by enhancing grid monitoring infrastructure through validated models and optimal sensor placement algorithms, minimising the necessary instrumentation. Methods to incorporate domestic smart meter data into distribution grid monitoring systems lead to reduced uncertainties without increasing the cost of the measurement systems. Topology estimation algorithms were developed that can identify unknown grid connections with limited instrumentation thus give the network operators the information they need to plan, update, maintain and operate their grids. Such knowledge is vital to facilitate greater utilisation of smart grid technologies. The models and algorithms outlined above have all been developed in collaboration with six distribution network operators, from throughout Europe, and validated on their respective grids.

Cyber security for grid measurement systems developed in the project will enable a secure grid and increase the uptake of smart grid technologies, leading to a more stable network with increased consumer confidence and reduced carbon emissions. Reports on the standardisation and security needs of Smart Grids by the committee working under European Mandate M/490 have been published, with input from the consortium.

This project will enable network operators to plan their network to be robust and secure, as well as cost effective. By minimising the number of expensive PMUs and deducing the full network topology, future network operators will be able to use renewable sources without compromising network security or power quality.

2 Project context, rationale and objectives

Project context

At present electricity distribution consists of centrally managed passive grids; however the need to integrate renewable generation has led to the development of active distribution grids where energy is fed in at the LV (AC voltage up to 1 kV) and MV levels (AC voltage in the range 1 kV to 35 kV) . Knowledge of the topology and power flow of such grids is limited, but this information is vital: to enable further integration of renewable and smart grid technologies; to provide for effective smart grid control and to ensure continuity of supply, with a reduced possibility of blackouts. To provide the necessary information for grid observation and control, networks of sensors are placed at multiple points in the grid. Such instrumentation is costly to install and maintain and the correct balance must be found between instrumentation cost and the provision of information of sufficient quality for effective grid observation and control. The precise structure and topology of distribution grids are often not known; however this information is required if retrofitted distributed renewable generation is to be installed and used reliably, whilst maintaining a stable and controllable network.

<u>Maximising the value of sensor technology:</u> Sensors installed in distribution grids tend to be power meters used for billing purposes and a smaller number of more advanced and more accurate power quality analysers. The monitoring of data from such instrumentation varies from 10 minute updates from the power analysers to daily updates from some meters to monthly or quarterly readings for billing purposes. As the measurement needs of distribution grids change due to increased renewable generation and changes in demand, it is essential that the best use is made of currently installed equipment and the installation of new equipment is well informed. Advanced instrumentation such as PMUs is expensive but could add significant value to distribution grid measurement systems. The benefits of such technology can only be assessed through a greater understanding of distributed measurement systems.

<u>Reducing costs:</u> With the large number of nodal points in distribution networks it is impractical and uneconomical to measure at every node and branch. For example, a UK DNO (Distribution Network Operator) is planning to install measurement equipment in over 12,000 substations at considerable cost and similar schemes may be required throughout Europe as ageing networks will be upgraded. If the cost of this sort of investment can be reduced the benefit to network operators and consumers is clear. A compromise must be reached between the cost of purchasing and placing a large number of sensors, and the accuracy of the knowledge obtained about the state of the grid. A EURELECTRIC survey of distribution network operators found that utilities regard optimisation of investments and operational costs as one of the top three priorities in distribution network R&D [1].

<u>Network management:</u> A paper by the Union of the Electricity Industry (EURELECTRIC) [2] states that the success of active distribution network management tools, required for the effective control of emerging smart distribution grids, "*will depend on DSOs' (Distribution System Operators') ability to actively monitor their grids, notably at medium and low voltage level. Today, DSOs have no systems installed for acquiring data from DG (Distributed Generation), in particular small scale DG. As the share of DER (Distributed Energy Resources) expands, DSOs will need monitoring, simulation, control strategies and advanced protection systems that allow them to supervise and control power flows and voltage in their MV and LV networks. This includes relevant monitoring functionalities from Smart Meters.*" Such instrumentation would require high voltage transformers and will be expensive to install and maintain. It is vital to limit the installation of such equipment to reduce the cost of Smart Grid operation to a manageable level. The potential use of Smart Meter data to fulfil all or part of this task should not be overlooked and could provide a cost effective method of monitoring the power flow in future grids. Further, the final May 2011 report of the CEN/CENELEC/ETSI Joint Working Group on Standards for Smart Grids [3] recognised the importance of "*enhanced monitoring and observability of grids down to the low voltage levels, also with the use of Smart Metering infrastructure*".

<u>Effective grid control:</u> This leads to a need for a sensor network that is optimised to provide the necessary information to effectively control the Smart Grid at the distribution level, while minimising the cost of the required sensors. Supervisory Control and Data Acquisition (SCADA) systems are only suited to centrally managed grids. These systems treat the MV and LV distribution networks as "black boxes" and little is known about the power flow and often even the topology of these networks. As such, new metrological techniques are required to ensure observability of these grids and enable their effective control. These techniques must expand on traditional metrology, which is focussed on individual measurements, and address the additional challenges when multiple simultaneous measurements are required. The distributed measurement system

must be treated as a whole. Recently developed state estimation and measurement have been shown to lend themselves well to this purpose. However, existing procedures employ simple random walk models for the system state dynamics without assessment of their applicability and they assume exact knowledge of the network topology and line impedances.

Grid stability**:** In addition to the SCADA systems mentioned above, PMUs are designed to be used for grid stability monitoring at the transmission level. They inform network operators of changes in voltage phase over a wide area, which can indicate instability and impending network failure. Their sophisticated functionality may also allow them to be used to compliment distribution level instruments and increase LV network observability without raising costs. First results for transmission level state estimation indicate that their use in state estimation and power flow determination could lead to improved uncertainty and therefore more reliable networks.

Objectives

The needs identified above lead directly to the following technical objectives of the project:

To develop and test sensor network metrology algorithms for static and dynamic state estimation and optimal sensor placement. The algorithms will be applied to actual LV and MV grids.

These algorithms are designed to maximise the use of sensors and additional data for the lowest cost, i.e. reducing the monitoring required to control grids effectively. The application to real grids is needed to demonstrate their use in the real world to give network operators confidence of their efficacy and that they will produce reliable results.

To investigate the use of Phasor Measurement Units (PMUs) for power flow calculation and state estimation in LV grids.

In addition to traditional sensors used for distribution grid monitoring, PMUs could lead to more accurate estimates of distribution grid states and it is therefore important that their potential benefits are assessed.

To apply Smart Meter data to network state estimation. This will involve investigating how low accuracy Smart Meter data can be aggregated to provide a similar or greater level of understanding of the grid state as measurements made at nodal points in distribution grids

Effective use of already existing measurement infrastructure is a potential way of reducing the need for expensive monitoring and smart meter data could be used to improve estimates of grid state. It is important to assess how effective such data can be if it is to be relied upon.

Knowledge of grid structure: The topology and impedances of distribution networks are often poorly documented due to inaccurate and missing feeder diagrams. Even when the documentation is in good order, it is difficult to have confidence in information that could be over 50 years old. Yet when connecting new renewables or retro-fitting Smart Grid elements to legacy networks, Distribution Network Operator (DNO) network planners use a system model based on these highly uncertain records to determine the load capacity and Power Quality (PQ) effect of new connections such as photo-voltaic (PV) or wind generation. Errors in this determination could lead to poor PQ after connection or the need for highly expensive and unnecessary network reinforcement. It is therefore crucial that the lack of knowledge of distribution network topologies, line impedances and power flows is addressed at the LV and MV levels. This knowledge is also required to give network operators confidence that their control algorithms are given accurate information on network power flow.

The following technical objective directly addresses this need for greater knowledge of distribution grid structure:

To determine uncertain distribution network topologies and line impedances and verify existing grid models using a series of on-site measurements and state estimation techniques

Security and reliability: It is also essential that the data flow between all components of sensor networks is secure and reliable. It is impossible to have a measurement system without a secure means of communication. Electrical grids are at risk from cyber terrorism, which could result in damage to equipment and widespread long term blackouts if security concerns are not addressed [4]. Smart grid monitoring and SCADA systems must be protected from this threat. New standards are emerging to ensure these issues are addressed as grids evolve. These include [5] and the start of the CEN/CENELEC/ETSI standardisation process. Smart Grid measurement systems must fulfil the requirements of these documents and the implications of such security measures on the uncertainty of sensor networks and their dynamic behaviour must be addressed. The EURELECTRIC survey mentioned above regards digitisation of control while maintaining data/cyber security as another of the top three priorities of utilities for research in distribution networks [1].

This need for secure and reliable sensor networks leads directly to the last technical objective:

To implement and validate a secured standardised distributed measurement system in LV microgrids and address the impact of security measures in the measurement system on the metrological requirements and uncertainties

3 Research results

To develop and test sensor network metrology algorithms for static and dynamic state estimation and optimal sensor placement. The algorithms will be applied to actual LV and MV grids

Distribution networks at present are comprised of a large number of nodal points but a limited number of measurement points. The transition to smart grids, with more generation at the low voltage and medium voltage, as well as storage, require an accurate knowledge of voltage levels and power flows at the nodal points and branches, however it is not cost effective to obtain measurements at every node and branch.

Estimation of the values at nodes and branches can be done using state estimation algorithms. A number of real measurements can be combined with state estimation techniques to obtain accurate up to date nodal voltage and power flows. With a limited number of sensors to be placed, the aim of the optimal sensor placement algorithms is to select the optimal location in order to obtain the most accurate estimations of these values for the lowest cost.

This objective consisted of two algorithm development challenges and their demonstrated application and validation with real distribution grid data, which was obtained from network operators who were stakeholders in the project. A dynamic state estimation algorithm, the Nodal load Observer (NLO) was developed to improve on estimates of voltage and power flow where measurement information is limited. This technique requires dynamic grid data that changes with time. Additional static state estimation algorithms were implemented and developed along with optimal sensor placement algorithms that determine the best measurement strategies to recover the power flow and voltages of grids for the lowest number of sensors.

The new state estimation algorithms, including the NLO, and sensor placement algorithms were applied to simulated networks, the University of Strathclyde's Power Network Demonstration Centre (PNDC) network and several real grids. The real grids are referred to in this report by the short names of the network operators, Zapadoslovenska Distribucna, a.s. (ZSDIS), Sakarya Elektrik Dagitim A.Ş. (SEDAŞ), ENDURIS, ENDESA (Smart City Malaga) and Alliander (LiveLab). The real grid data was processed by TUBITAK, SMU, VSL, FFII and CIRCE with assistance from the network operators. These partners were also involved in the application and testing of the algorithms developed by PTB and NPL.

The configuration of the PNDC, subsequent data acquisition and application of the algorithms and their testing on the PNDC was carried out by NPL, PTB and REG(STRAT). The PNDC has an outdoor compound with interconnected 11 kV and 400 V networks and can be configured as an urban, hybrid (urban/rural) and/or rural network, with a capability of emulating 11 kV distribution lines of up to 60 km in length. Furthermore, the centre has a Real Time Digital Simulator (RTDS) system able to simulate a wide range of power system networks and interact with the PNDC distribution network extending its capabilities. The figure below shows the PNDC network topology and includes some of the measurement equipment acquired for the project. The PNDC network is on the left and the extended network including the RTDS is on the right.

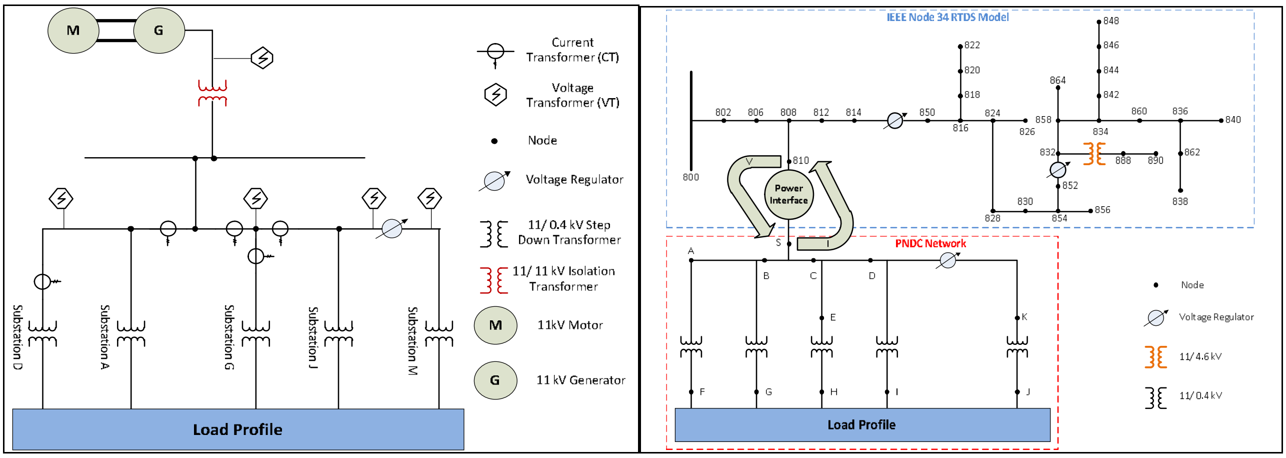


Figure 1: Schematic diagram of the PNDC network and RTDS extension.

The work carried out with the NLO is described first, followed by a brief section on the sensor placement algorithms and their application to simulated data, the PNDC and real grids. With the nodal load observer (NLO) from the EMRP project ENG04 SmartGrid, an initial working version of a quasi-dynamic state estimation algorithm was available at the start of this project. The NLO is based on the extended Kalman filter method and aims at estimating and correcting the errors of the pseudo-measurements in conjunction with the estimation of electrical grid parameters. A comprehensive literature survey at the beginning of this project showed that this is a fairly unique and promising approach to state estimation in MV and LV electrical distribution networks. However, the original version of the NLO had a number of serious shortcomings that were identified during the previous project. The main disadvantages were the very simplistic dynamic model for the evolution of the pseudo-measurement errors, the limitation to single-phase networks, the lack of a concise treatment of measurement uncertainties and the limitation to measurements of nodal voltages and bus power.

To this end, PTB together with TUC developed an extension of the original NLO algorithm to take into account also nodal currents, power measurements between buses as well as topology parameters such as line impedances. This was accomplished by using in the Kalman filter model a measurement equation that is very closely related to static state estimation. In this way, all network state measurements, which are mathematically related to nodal voltages, can be taken into account straightforwardly. In static state estimation the sought parameter in the optimization are the nodal voltages. However, in order to incorporate this model into the NLO Kalman filter, it had to be considered a function of the pseudo-measurement errors, i.e. the Kalman filter states. Therefore, PTB and TUC developed an approach to estimate nodal voltages using a subset of the available measurements and the technique of optimal power flow calculations. In a second step, these nodal voltages are plugged into the Kalman filter measurement equation, which is then considered a function of the Kalman filter states. Using the chain rule of differentiation, re-using the Jacobian of the optimal power flow calculations and the Jacobian from the original NLO, an easy to calculate Jacobian for the extended Kalman filter could be derived. In this way, an efficient implementation of an extended NLO was achieved.

With support from the other partners, PTB and TUC successfully applied the NLO algorithm to simulated data with the network model of the Alliander LiveLab, measurement data from the Smart City (Malaga) network, the PNDC network and the ENDURIS grid. The analysis with simulated data for the Alliander LiveLab grid model was used to successfully validate the extended NLO method under very well controlled conditions. The PNDC network and the ENDURIS grid provided actual redundant measured data under realistic conditions with a small number of nodes in the PNDC network, though, difficulties with the measured data were observed regarding the behaviour of the transformer. The NLO was applied successfully to that network, but the remaining estimation errors may originate from a non-constant or non-linear transformer effect. These investigations will be a topic of future research. The Smart City network provided a medium-sized grid model with 100 buses and redundant measurement data. It was used to demonstrate the efficient application of the extended NLO to larger networks and its numerical performance in such cases. The analysis of the results obtained for this network showed the ability of the extended NLO to estimate a range of network parameters. Therefore, various different scenarios were investigated with this network by replacing a number of randomly selected buses with constant pseudo-measurement values. It could be shown that even for a reasonably large number of pseudo-measurements in the network, the extended NLO provided good estimates of the nodal voltages and bus powers. However, issues with the measured data were identified that could not be resolved within the lifetime of the project. A topic of future research will thus be the investigation of the remaining differences between estimated and measured grid parameters.

An advantage of the extended NLO compared to the original NLO is the straightforward incorporation of uncertainties associated with all measured network state parameters due to the extended measurement model. In contrast, the original NLO only took into account uncertainties associated with measured nodal voltages only. With the extended measurement model, the state covariance matrix estimated by the Kalman filter for the pseudo-measurement errors can be employed to evaluate the uncertainty associated with the estimated network state parameters. Furthermore, PTB investigated the compliance of the thereby obtained uncertainty with the *Guide to the Expression of Uncertainty in Measurement* (GUM) – the quasi-standard for uncertainty evaluation in metrology. Therefore, PTB analysed the linear Kalman filter and the extended Kalman filter regarding their calculation of the state covariance estimate from a GUM perspective. It was concluded that the linear Kalman filter completely complies with the GUM and its Supplements, while the extended Kalman filter complies with the *Law for the propagation of uncertainty* (LPU) of the original GUM document. Consequently, it was concluded that the extended Kalman filter method of the NLO complies with the GUM in terms of evaluation of uncertainties.

Typically, MV and LV grids are three-phase networks and especially LV grids cannot be expected to have symmetrical loads. Therefore, PTB and TUC extended the NLO algorithm to three-phase three-wire networks with unbalanced load conditions. This required to extend the admittance matrix used in the NLO calculations to such network models and to reformulate all calculations accordingly. With support from TU-E, the three-phase NLO algorithm was successfully validated on actual measurement data from the Alliander LiveLab.

In order to overcome the NLO's shortcoming of a very simplistic dynamic model for the pseudo-measurement errors, PTB developed a flexible and versatile approach based on auto-regressive moving-average (ARMA) stochastic process models. Therefore, the state equation in the Kalman filter model was replaced by an ARMA model equation. The ARMA model is a generic parametric model of stochastic processes driven by a white noise process for which a large amount of methods is available in the literature. The original dynamic model of the NLO can be interpreted as an ARMA model with just one parameter. By increasing the number of parameters a more flexible model can be obtained, which can cover a wider range of pseudo-measurement errors in the NLO. As a first step, PTB employed a two parameter ARMA model in conjunction with the original measurement model of the NLO. Initial tests with simulated data for a small example from the UKGDS grid database showed promising results. However, the challenge was the determination of appropriate ARMA model parameters. To this end, PTB adapted a recently proposed approach for the online estimation of ARMA model parameters. The online estimation method was incorporated into the NLO algorithm in such a way that at each time step first the ARMA model parameters including the variance of the driving noise was updated and then the Kalman filter step carried out with the updated parameter values. Application of this approach to simulated data from the UKGDS network and the Alliander LiveLab network demonstrated that the NLO with online ARMA parameter estimation is still working in situations where the NLO with fixed ARMA parameter values became numerically unstable. Future research will focus on implementing the two parameter model to actual measurement data and medium-sized networks and on the extension of the implementation for higher-order ARMA models.

In addition to the NLO, two static state estimation algorithms were used for this work. These are a weighted least squares method included in the Matpower software [6] and a new approach developed by NPL using a convex relaxation based on semi-definite programming and Burer Monteiro factorization [7]. Sensor placement for small grids can be addressed using standard techniques based on the theory of Design of Experiments as in the book by Boyd and Vandenberghe [8] where the problem is restated (in a simplified form) as a convex optimization problem by means of Semi-Definite Programming relaxation techniques. This technique has proved efficient for a number of practical problems when the observations are linear functions of the parameter of interest that needs to be estimated. In the case of electricity networks this is not the case, the functions are quadratic.

In order to address the problem, the recent approach by Lavaei and collaborators was considered. In the paper by Lavei and Low [9], the authors proved that the optimal power flow problem could be solved exactly using a semi-definite programming based relaxation. Since then, the semi-definite programming relaxation approach has become a standard tool in power grids studies when the network's dimension is small or mild. NPL improved on these techniques to devise a fast and scalable algorithm for networks with a large number of nodes and edges for this project. The method is based on a refined analysis of perturbation of the spectrum for tall matrices after appending a column which is sufficiently incoherent with respect to columns of the tall matrix it is appended to.

Some example results of testing the state estimation method with simulated data are given below. NPL conducted some numerical experiments with the new state estimation algorithm, on various grids including IEEE - 13 bus and IEEE - 30 bus grids [10][11]. Two approaches were compared. The first approach is the new method for problem and the second approach uses the YALMIP package in Matlab for solving the Semi-Definite Programming Relaxation [12]. The new method achieves much better accuracy (around a factor of 5 for the IEEE13 network (shown in the figure on the left below) and around a 10 % improvement for the IEEE30 network) and converges much faster (10 times faster for the IEEE13 network and more than 25 times faster for the IEEE30 grid (shown in the figure on the right below) than YALMIP.

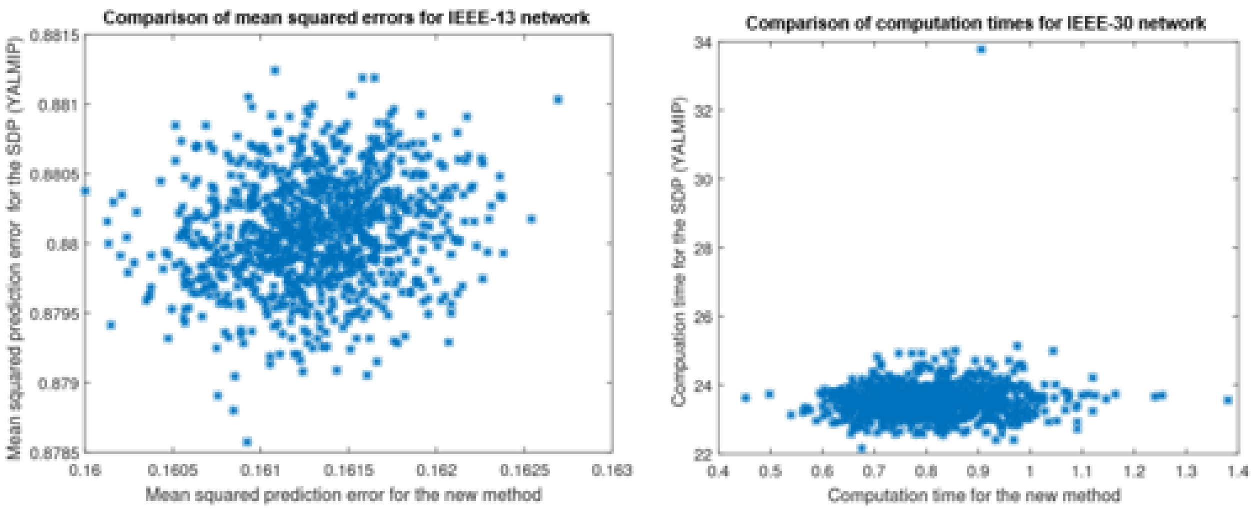


Figure 2: Comparison of new method with YALMIP package. Mean squared errors are compared in the plot on the left for the IEEE-13 network and computation times for the IEEE-30 network are shown in the plot on the left.

Further testing of the sensor placement algorithms was carried out on the Power Network Demonstration Centre (PNDC) and a sample of the results of this testing is given below:

The sensor placement algorithm was applied with different numbers of sensors. 164 possible measurement locations were available (these include active and reactive power in the branches and voltage magnitude at the buses, voltage angles are not included. Each measurement is considered separately, i.e. if active power is measured in a given branch, reactive power in that branch is not automatically chosen).

We then compared the placement with random placements. The adjacent figure shows the histogram for the root mean squared error when 61 placements are drawn uniformly at random. We also show (red dot) the root mean squared error obtained using our new methodology with 61 measurements placed in the locations chosen by the algorithm. As these results show the method performs better than a random placement with high probability.

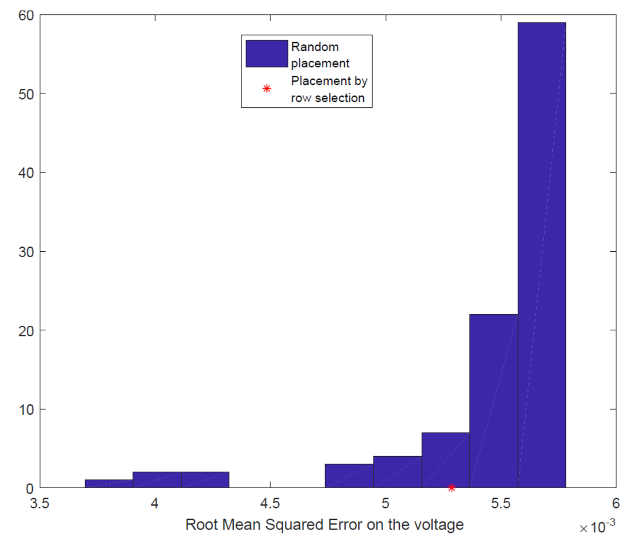


Figure 3: Histogram of mean squared errors in the recovered voltages

Further testing was carried out on the fast state estimation method and the placement method on several real distribution grids. An example of some of the test results is given below.

The performance of the placement method on the ZSDIS Grid is shown in the figure on the left below. This figure shows the histogram for the root mean squared error when placements are drawn uniformly at random. The root mean squared error obtained using the new methodology is shown as the red dot on the figure. 68 sensors were placed. As these results show the method performs better than a random placement with reasonable probability. The test was repeated with the ENDESA grid with 75 sensors placed. These results are slightly better than those for the ZSDIS grid, showing that the method performs significantly better than the random placements with relatively good probability.

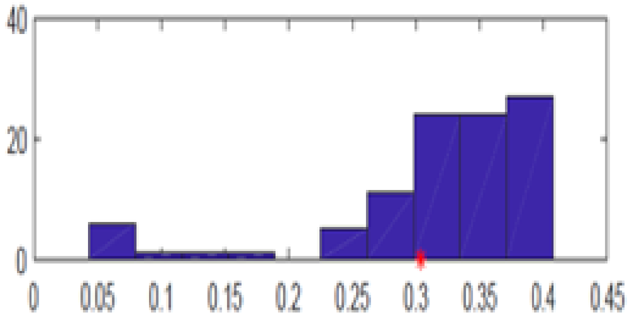


Figure 4: ZSDIS network

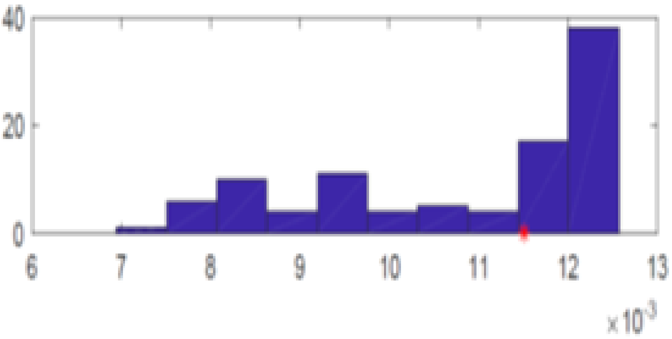


Figure 5: ENDESA network

The results for the NLO and sensor placement algorithms clearly show that the objective to enhance the observability of distribution networks has been met by the project and these algorithms are now applicable to a wide range of networks. They have the potential to reduce the amount of grid monitoring required to obtain the required knowledge to effectively operate distribution grids and plan for their continued evolution as part of a low carbon electricity network.

In conclusion, several state estimation and sensor placement techniques were developed for the project and applied to real distribution grids. Their efficacy has been thoroughly tested and they are now available for use to increase the capability of network operators to effectively monitor and therefore control their grids.

To investigate the use of Phasor Measurement Units (PMUs) for power flow calculation and state estimation in LV grids

For effective grid control there is a need for a sensor network that is optimised to provide the necessary information to effectively control the Smart Grid at the distribution level, while minimising the cost of the required sensors. Sensors in commonly used Supervisory Control And Data Acquisition (SCADA) systems in distribution grids tend to be power meters used for billing purposes and a smaller number of more advanced and more accurate power quality analysers. The monitoring of data from such instrumentation varies from 10 minute updates from the power analysers to daily updates from some meters to monthly or quarterly readings for billing purposes. As the measurement needs of distribution grids change due to increased renewable generation and changes in demand, it is essential that the best use is made of currently installed equipment and the installation of new equipment is well informed. In this project we investigated the use of Phasor Measurement Units (PMUs) as advanced instrumentation that is expensive but might add significant value to distribution grid measurement systems.

In addition to the SCADA systems mentioned, PMUs are designed to be used for grid stability monitoring at the transmission level. They inform network operators of changes in voltage phase over a wide area, which can indicate instability and impending network failure. Their sophisticated functionality may also allow them to be used to complement distribution level instruments and increase LV network observability without raising costs. First results for transmission level state estimation indicate that their use in state estimation and power flow determination could lead to improved uncertainty and therefore more reliable networks.

The application of PMUs at the distribution level is an active area of research, but little real use of PMUs has been demonstrated in real working grids. The installation of PMUs in the Delta MV distribution network in the Netherlands has provided vital information on the improvements PMUs can have on state estimation if used at the distribution level. Further, estimates of the accuracy requirements of PMUs for adequate observability of the grid lead to enhanced grid control systems.

The approach in this project is to apply algorithms for the state estimation of a real distribution grid using both SCADA data and PMUs and to provide a comparison of methods of sensor placement and state estimation when PMUs are included. A 50 kV distribution network from ENDURIS in the south-west part of the Netherlands was used to provide real data for comparing state estimation algorithms applied to PMU data with SCADA data. The grid was equipped with a SCADA system already, whereas calibrated PMUs have been installed at the beginning of the project. The physical location of the substations is shown in the map below and the position of the PMUs is indicated in the schematic.

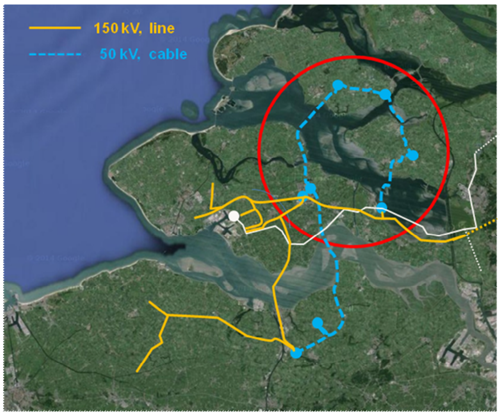


Figure 6: Geographical map of ENDURIS grid

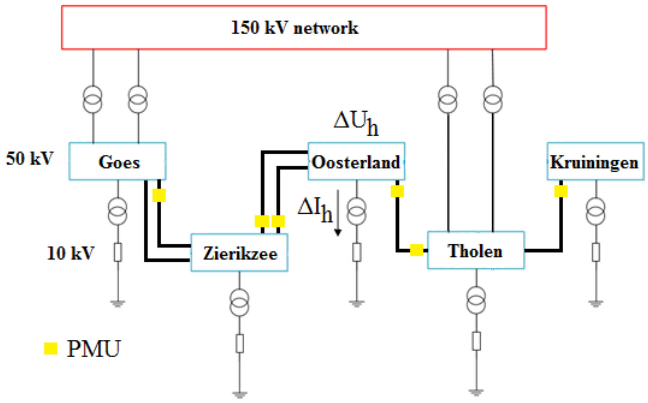


Figure 7: Schematic diagram of ENDURIS grid

Distribution networks at present are comprised of a large number of nodal points but a limited number of measurement points. The transition to smart grids, with more generation at the low voltage and medium voltage, as well as storage, require an accurate knowledge of voltage levels and power flows at the nodal points and branches, however it is not cost effective to obtain measurements at every node and branch.

Estimation of the values at nodes and branches can be done using state estimation algorithms. A number of real measurements can be combined with state estimation techniques to obtain accurate up to date nodal voltage and power flows. With a limited number of sensors to be placed, the aim of the optimal placement sensor algorithms is to select the optimal location in order to obtain the most accurate estimations of these values.

Several methods of optimal sensor placement which work with static data were presented and tested with simulated data. The uncertainty of power and voltage magnitude sensors was fixed at 5 % and the uncertainty of the PMU's was varied from 5 % to 0.5 %. One of the algorithms was modified to assign a cost to each sensor location and when cycling through sensor locations only considering configurations that are in budget. The algorithms were shown to identify the best locations to place PMUs taking into account their relative increased cost and accuracy for a variety of budgets and accuracy gains. The static state estimation methods were not convergent when applied to the model of the 50 kV section of the ENDURIS grid so it was not possible to provide an assessment on the PMU placement with these methods. Other networks were studied and it can be seen that the uncertainties in the state estimation are significantly reduced with a small number of PMUs, but the addition of more PMUs tends to have a smaller improvement. The precise variation of uncertainty with number of PMUs depends on the size and complexity of the network.

The state estimation algorithms used for this work are a weighted least squares method included in the Matpower software, the Nodal Load Observer (NLO) and an approach using a convex relaxation based on semi-definite programming and Burer Monteiro factorization.

The purpose of the NLO is to determine the grid state in medium voltage distribution grids with incomplete measurement infrastructure. The original procedure is based on measurements of voltage phasors at grid buses and forecasts of load and generation data. The basic idea is to reconstruct unknown load and generation data and correct incorrect forecasts through all available measurements of voltage phasors over time, and then determine the grid state based on these reconstructed and corrected values. Rather than using possibly incorrect forecasts directly for determination of the grid state, the nodal load observer first uses all measurement information available to adapt the forecasts as much as possible to the actual situation of the grid. Even if only very few measurements are taken, major improvement of forecasts is achieved in a neighbourhood of the measurement and as much improvement as possible for buses further away from it.

The original NLO algorithm, developed in the EMRP project ENG04 SmartGrid, was capable of taking into account measured nodal voltages and bus powers. Hence, in principle it could be applied to networks with PMU measurements straightforwardly. However, advantages of PMUs are the high measurement frequency and the small measurement uncertainties which could not be fully exploited by the original NLO. To this end, PTB and TUC improved the implementation of the NLO to increase its numerical performance in order to be applicable for high-frequency measurements. In addition, the extended NLO as described in Section 3.1 allows to take into account uncertainties associated with the measured bus power. The extended NLO was applied to the 50 kV section of the ENDURIS grid using data from one and two PMUs, respectively, in order to assess the general benefit of including measurements of voltage phase. It was concluded that with an increasing number of PMU voltage measurements in the network, the estimation quality of voltage amplitude and phase improved for the whole network. The NLO is shown to be an effective state estimation technique that can take into account PMU data and improve on the accuracy of distribution grid monitoring with a limited number of PMUs available.

In addition, TUC outlined an initial proof-of-principle method for a novel two-step quasi-static state estimation method that uses the PMU current measurements and the traditional measurement values. Based on the availability of power, voltage and current measurements with PMUs, a linear state estimation method could be developed. This has the advantage that states can be computed directly without an iterative algorithm, which is much faster and presumably more robust. As a distribution network is typically not instrumented fully with PMUs, pseudo measurements could be derived from the results of state estimation with measurements from conventional measurement data. The below flow chart illustrates a possible approach connecting conventional and PMU measurement data. The further development of this approach and its validation will be a topic of future research.

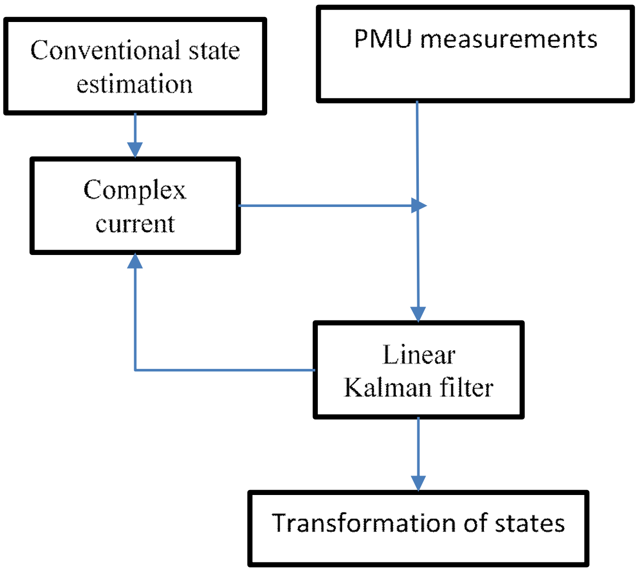


Figure 8: Flow chart showing the introduction of PMU measurements to enhance state estimation with the NLO.

In conclusion, state estimation algorithms were modified to take into account PMUs for distribution grid monitoring and their use in this project has proved that the use of PMUs in state estimation can significantly reduce the uncertainties and be cost effective. The algorithms are now available for use for other grids so that grid operators can perform cost-benefit analyses when considering the use of PMUs on their grids.

To determine uncertain distribution network topologies and line impedances and verify existing grid models using a series of on-site measurements and state estimation techniques.

Optimal operation of the distribution network depends not only on the correct estimation of nodal voltages and power flows, but also its operational topology [13]. Knowledge of the correct topology is essential for safety service restoration after outages, failure identification, grid reconfiguration, etc. [14].

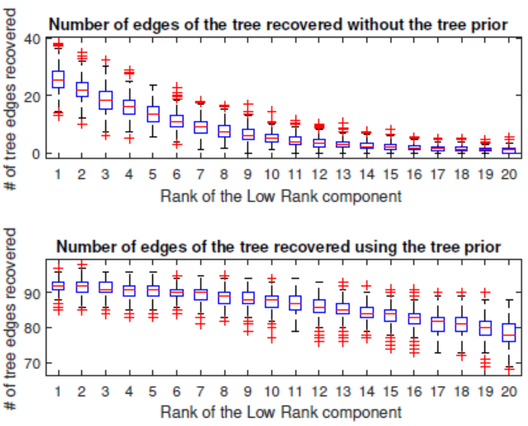
Two algorithms were proposed by NPL and REG(STRAT) with the aim of determining the topology of the distribution network of interest.

The first algorithm is based on the approach proposed by Yuan, Ardakanian, Low, and Tomlin [15]. The approach promoted in that paper is to partially recover the topology by assuming that there is a subtree in the network. Based on natural assumptions, the authors deduce that the matrix that links the currents and the voltages at the buses of the tree has a special property: it is the sum of a sparse matrix which is the adjacency matrix of the subtree and a low rank matrix. Surprisingly enough, the problem of recovering the sum of a low rank and a sparse matrix was studied independently in the statistics and machine learning communities and is known as the Robust PCA problem. Our main contribution is to complement the results in the paper [15] by introducing the tree prior information explicitly in the reconstruction algorithm. This is done by performing an alternating minimization procedure using successive steps in the tree space and steps in the low rank space.

The validation of this algorithm is done by utilizing simulated data in the first place, and real data from the ENDESA Malaga Smart City grid. A full description of the algorithm and its testing can be found in the paper *Application of Robust PCA with a structure outlier matrix to topology estimation* [16].

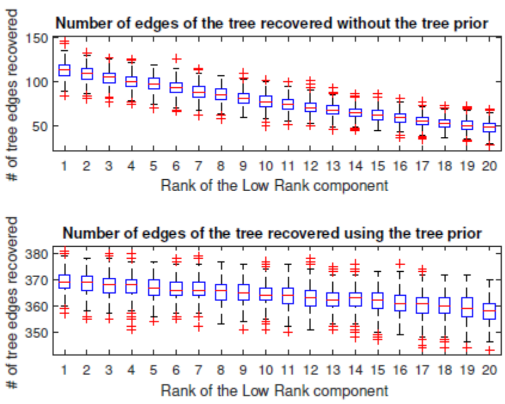
The second algorithm was proposed in the technical report *Structure learning and estatistical estimation in distribution networks - Part I* [14], this algorithm aims at learning the grid operational structure for radial distribution networks. The algorithm is based on graph theory, where a graph consists of ordered pairs of vertices and edges (V, E), and the edges joining pairs of vertices [17]. In this particular case the vertices will correspond to the nodal points and the edges to the branches on the distribution network of interest. The algorithm recovers the structure of the network from the nodes at the end to the substation they are connected to.

The first algorithm was tested on simulated data by applying the algorithm to randomly generated graphs with some constraints and observing the number of correctly recovered edges. We ran several Monte-Carlo simulations. The results are presented in the figures below.



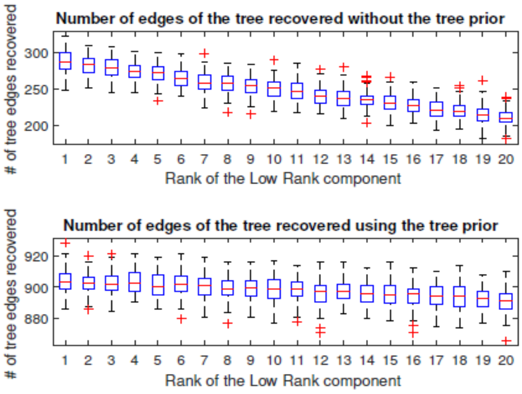
(a) Comparing recovery with $N = 100$ nodes (target 99 edges)

Figure 9: Number of recovered edges against matrix rank with and without prior tree (bottom and top plot respectively) (N=100 nodes)



(a) Comparing recovery with $N = 400$ nodes (target 399 edges)

Figure 10: Number of recovered edges against matrix rank with and without prior tree (bottom and top plot respectively) (N=400 nodes).



(a) Comparing recovery with $N = 1000$ nodes (target 999 edges)

Figure 11: Number of recovered edges against matrix rank with and without prior tree (bottom and top plot respectively) (N=1000 nodes)

The method was tested with the ENDESA Malaga Smart City network. This is an 11 kV urban network fed from a 33 kV supply point. The grid we used consists of 100 buses and 50 branches, with 2 generators supplying the medium voltage network which also feeds a low voltage network, which has 9 load buses with power demands of around a few hundred kilowatts. Since the entire Malaga grid is a tree it is therefore amenable to our method which uses tree structured sparsity. Observations were obtained at 50 randomly chosen locations in the grid. The method was run with different priors on the rank of L_0 (from 5 to 20) in order to show the influence of parameter misspecification on the structure recovery. We observed that most edges of the graph can be recovered using a good prior on the rank of L_0 (see [16]). Some edges were not correctly recovered but the overall reconstruction seems satisfactory given the difficulty of the problem.

For the application of the second topology algorithm, proposed by Deka, Backhaus, and Chertkov [14], to the PNDC just a single phase is considered. A total of 1200 measurements of voltage deviation, active and reactive power were taken from each node during a 20 minute period, with load changing in steps. Resistance and reactance in each branch are known.

At low tolerance values (see [14]) the topology algorithm struggles to reconstruct the network, being able to reconstruct connection between 3 nodes for a tolerance of 0.01. If a large tolerance value is used, close to 1, the network is reconstructed almost completely, only one is not correctly assigned to the correspondent branch, however this might lead to unconnected nodes appearing as being connected as mentioned in [14].

Further work was carried out by PTB and TUC to determine uncertain topology parameters. They further extended the NLO described in Section 3.1 to include these topology parameters in the measurement model. Therefore, the line impedances where considered as virtual states of the network. In this way, the estimates of the topology parameters are updated based on new measurement data using the Kalman filter method. However, the increase of the state vector dimensionality also requires to increase the number of independent measurements in the network in order to achieve observability for the static state estimation problem and numerical stability for the nodal load observer Kalman filter. The implementation of this approach for the NLO was successfully validated using a small proof-of-principle network and simulated data. Also for this example static state estimation was compared to the NLO and led to the same results.

In conclusion, topology estimation algorithms were implemented and refined and were found to be effective at recovering unknown connections in a number of networks. Topology estimation is an extremely challenging problem and successful testing of such algorithms is an important addition to the current state of the art.

To apply Smart Meter data to network state estimation. This will involve investigating how low accuracy Smart Meter data can be aggregated to provide a similar or greater level of understanding of the grid state as measurements made at nodal points in distribution grids.

A power system is fully observable if a unique solution of the state estimation function can be obtained. In general, an increase in the number of measurement data improves the numerical observability of a power system. However, there are insufficient measurement data for state estimation in most of the distribution networks for economic and technical reasons. Conventionally, only measurements at the substation and critical loads are available to grid operators of the distribution network. In order to execute the state estimation function on the numerically unobservable parts of a distribution system, pseudo-measurements are adopted to augment the available measurements. Pseudo-measurements are typically obtained from historical data, generation dispatch or short term load forecasting. Although pseudo-measurements make the system artificially observable, the poor accuracy notably affects the performance of distribution system state estimation (DSSE). Conventional state estimators that use a weighted least square (WLS) method might even fail to function due to a large amount of gross errors in the pseudo-measurements.

In the last few years, the introduction of an advanced metering infrastructure in the distribution system provides an opportunity to use smart metering data for DSSE, instead of pseudo-measurements. Unlike conventional electricity meters that can only measure the total amount of electricity over a certain billing period, smart meters are able to record and store the electrical consumption at given intervals, e.g. every 15, 30 or 60 minutes. Smart meter devices are typically installed at end-users on the low-voltage (LV) feeders. Hence, for medium-voltage (MV) distribution networks, a set of smart meter data needs to be processed before being employed as an MV nodal input for the state estimation algorithm.

In this project, a new way of utilizing and processing smart meter data for the purpose of the DSSE in MV distribution networks was introduced by VSL and REG(TU-E), and the associated uncertainty due to several identified error sources was calculated. Furthermore, the influence of uncertainty associated with the aggregated smart meter data on the DSSE in MV distribution networks was investigated.

Ideally, active or reactive power at the MV side of an MV/LV transformer is equal to the summation of meter readings of all connected end-users on the downstream LV feeders. That is, the power injection at an MV bus can be directly obtained through a bottom-up approach at every time instant. However, apart from the data management system to function properly, there are several assumptions which are not fully feasible in real power systems:

- All loads are equipped with smart meter devices;
- Phase connection of each meter to the grid is known;
- All the measurements are perfectly synchronized;
- Readings of an individual smart meter are free from error;
- No power losses are present in the transmission and distribution.

The methodology developed in this project to provide a reliable estimation of the aggregated smart meter data contains three steps: phase identification, data aggregation and uncertainty evaluation.

In a LV distribution system, the connectivity information of end-users on the LV feeder is mostly incomplete or missing. Given the time series of voltage magnitudes at each end-user and also at the LV side of a MV/LV transformer, we used a cross-correlation algorithm to implement the phase identification. The basic principle is that the correlation between two voltage profiles over time from different metering sites on the same phase is stronger than two voltage profiles over time from metering sites which are physically close but on different phases.

Most smart meters are not only able to record the consumed energy, but also the energy that is delivered to the network by distributed energy resources, if applicable. In the net feed-in tariff scheme, data aggregation can simply be obtained by summing up all the smart meter readings by phase, whereas for the gross tariff feed-in scheme, the delivered energy has to be subtracted from the consumption.

The combined total uncertainty of the aggregated smart meter data is a combination of the uncertainty contributions that are related to the assumptions mentioned above and that can be calculated or estimated. Several scenarios have been considered, in specific with smart meter accuracy either fully dependent (i.e., all have the same deviation) or fully independent, and different distributions for the synchronization error that can be calculated using statistical analysis.

A typical European LV distribution system in combination with real-world smart meter data is used to demonstrate the performance of the proposed methodology. The IEEE European Low Voltage Test Feeder (available online) is a typical three-phase LV feeder in Europe, which is a radial distribution system with a fundamental frequency of 50 Hz. Through a transformer at the substation, the (phase-to-phase) voltage level of the main feeder and laterals is stepped down from 11 kV to 416 V. On this LV feeder, there are 55 residential loads in total. Each load is connected to the grid by means of a single-phase connection as shown in Figure 12. The external MV grid is modelled as a voltage source with impedance.

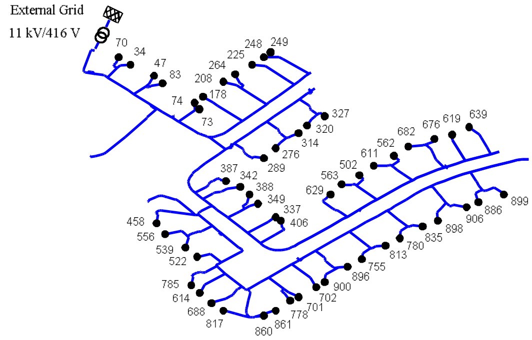


Figure 12: Single-line diagram of the IEEE European LV Test Feeder.

Real-world smart meter data for residential customers within Europe from 01/01/2013 00:00 to 31/12/2013 23:45 in the time interval of 15 minutes was used. The (average) daily load profiles over one year is shown by Figure 13. For the purpose of implementing the phase identification before the aggregation, voltage profiles of each load and LV side of the transformer were calculated by means of the time series power flow in the electrical power simulation tool OpenDSS.

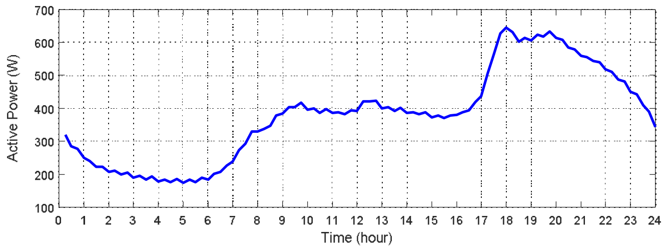


Figure 13: The (averaged) daily load profile of 55 loads over one year.

Two cases have been investigated by VSL and REG(TU-E). In the high-accuracy case I, the phase identification error is set to be zero; the accuracy of the smart meters is Class 0.5; the length of unsynchronized time interval is 5 s; the estimation of power loss is represented as a triangular random variable Tr(0.5 %, 1.5 %, 2.0 %); and the estimation of missing data follows Tr(4.0 %, 4.5 %, 5.0 %). In case II, the phase identification accuracy is set to be 95 %; the accuracy of the smart meters is Class 2; the length of unsynchronized time interval is 20 s; the estimation of power loss is represented as a triangular distribution Tr(0.5 %, 1.5 %, 3.0 %); and the estimation of missing data follows Tr(4.0 %, 4.5 %, 6.0 %). Uncertainties associated with the aggregated smart meter data over the whole time horizon can be analysed. Uncertainty bounds of the aggregated data in both two cases are illustrated in Figure 14.

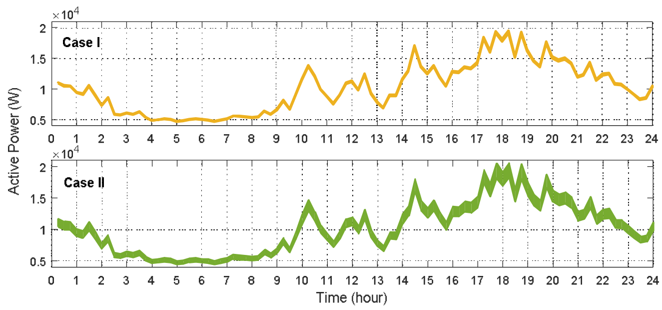


Figure 14: Uncertainty bounds of the aggregated smart meter data.

From the simulations described above, we conclude that by means of the proposed method of data processing, a reliable MV nodal power for the use of DSSE is obtained in terms of a mean value with an uncertainty. It is noted that the accuracy level of the aggregated data is lower than that of the original smart meter (0.5 % to 2 %), but higher than the hypothesis (10 %) used in previous literature [18][19]. Compared to the pseudo-measurement with a maximum error around 30 % - 50 %, which is commonly used in the case of the absence of real-time measurements, the advantage of the utilization of smart meter data in DSSE is obvious. More details on uncertainty analysis of aggregated smart meter data for state estimation can be found in the conference proceeding *Uncertainty analysis of aggregated smart meter data for state estimation* [20].

After having found a suitable method to provide a reliable value of the aggregated smart meter data with uncertainty, the impact of using smart meter data on the estimated states of two three-phase MV distribution networks is investigated by comparison to estimated states using data from traditional meters and pseudo-measurements. For this purpose the IEEE 13-node test system and the IEEE 34-node test system (available on-line) are modified to test the behaviour of the estimator in different cases, corresponding to different measurement configurations, and different scenarios, corresponding to different uncertainties of the aggregated smart meter data. In order to simplify the computational complexity, reasonable modifications are made on the two test systems:

- The distributed load along the line is lumped and equally divided into two end node of the line;
- All loads are changed into star connection;
- Voltage regulators, tap changer transformers and switches are all omitted;
- All transformers are modelled by constant impedances;
- All branches are three-phase connected.

The measurement configuration, including the type, location and accuracy of measurements, influences the quality of estimation results. In our research, the power injections at an MV bus, regardless of being obtained by aggregating smart meter data of its downstream LV feeders or being measured directly by traditional meters, are treated as real-time measurements. In addition to nodal powers, branch powers are taken into account as extra real-time measurements.

In the simulations, to obtain a reliable estimate of the actual accuracy level with a certain probability distribution, sufficient possible measurements are necessary to do the statistics. Therefore, 10 000 sets of measurements, covering most possible variations, are generated and used in the calculations.

For the IEEE 13-node test system (shown in Figure 15), bus 650 is selected as the slack bus providing the reference voltage. For the available data, four test cases are considered in this test system. In the different test cases, the number of buses with values based on aggregated smart meter data is changed, as well as the amount of extra measurements of branch power that are also taken into account. For each test case, the impact of using the smart meter aggregated data on the estimator is investigated by calculating the mean error for four different scenarios with aggregated data uncertainties of 1 %, 5 %, 10 %, 50 %, respectively. Note that 1 % uncertainty in fact corresponds to having a good conventional meter installed at the MV-LV transformer, whereas 50 % reflects the situation of using pseudo-measurements. From the simulations we find that the estimator works better with a higher accuracy level of aggregated data in all test cases. In other words, the accuracy of DSSE results in the four uncertainty scenarios is in descending order, as expected. As an example, Figure 16 shows the results for one of the test cases.

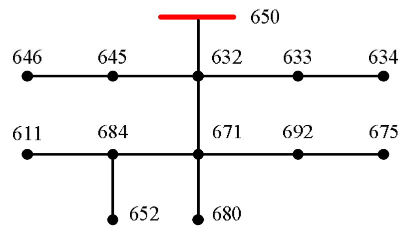


Figure 15: Single-line diagram of the IEEE 13-node test feeder.

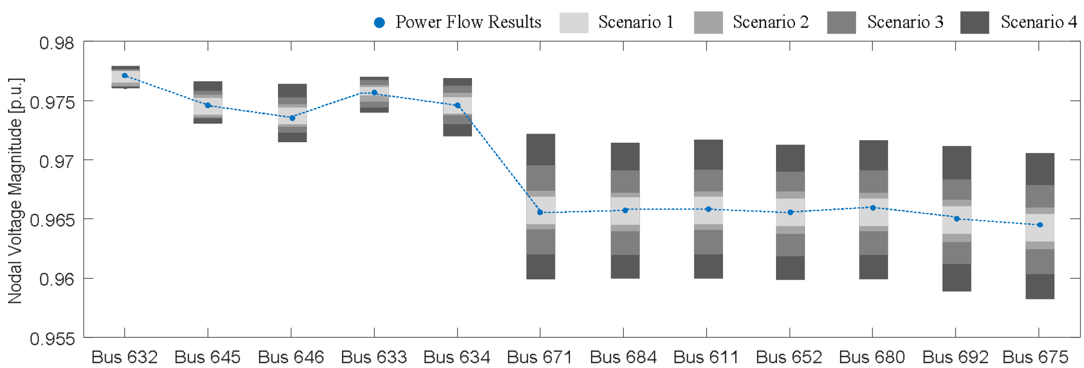


Figure 16: Boundaries of DSSE results for the four uncertainty scenarios of 1 %, 5 %, 10 %, 50 %, respectively, in the case where all buses are based on aggregated smart meter data.

In the IEEE 34-node test system, shown in Figure 17, there are 34 buses in total, including one slack bus (Bus 800) and one zero-injection bus (Bus 802). Two test cases have been investigated that only differ in the measurement configuration for nodal powers. From simulations on these two test cases we conclude that the errors with respect to three-phase nodal voltages increase with increasing uncertainty of the aggregated smart meter data, which is consistent with the results from the simulations on the 13-node test feeder.

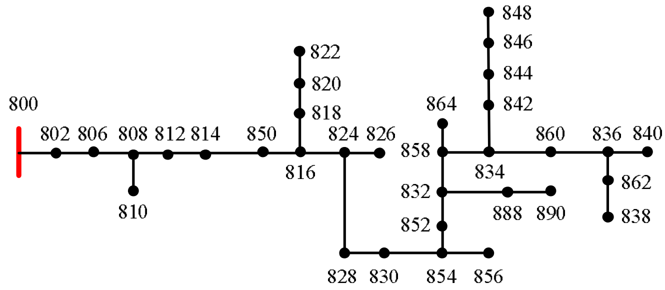


Figure 17: Single-line diagram of the IEEE 34-node test feeder.

Our results show that for use in DSSE, the accuracy level of the aggregated data is of great importance on the estimation results, especially when extra measurements are hardly available. The influence of the uncertainty of the aggregated smart meter data on the estimation results depends on the measurement configuration of the network. If only a small number of extra measurements are available, the performance of the state estimator improves with the accuracy of the aggregated data. More details on DSSE with aggregated smart meter data can be found in the paper *On the evaluation of uncertainties for state estimation with the Kalman filter* [21]. NPL performed similar experiments with data from the ZSDIS and PNDC grids and came to similar conclusions.

By taking advantage of state estimation with the smart meter data on LV feeders, the planning and operation in MV distribution networks can be further improved, for example by improved Volt/VAR optimization (optimally managing voltage levels and reactive power to achieve more efficient grid operation), network reconfiguration and demand response.

In addition to the work carried out about, based on the extended NLO described in Section 3.1 and the findings from the analysis of the Smart Meter data aggregation methods, PTB and TUC investigated the potential influence of Smart Meter data in an actual electrical grid on the NLO estimation performance. Therefore, for a number of randomly selected buses the uncertainty associated with measured bus power was increased in accordance with the findings from the data aggregation method. Analyses for the Smart City network showed that the influence of the increased uncertainties on the quality of the estimated states was negligibly small for the extended NLO. Further investigations led to the conclusion that the reason for this appears to be the way in which the extended NLO uses a subset of the measured bus power to carry out the power flow calculations and estimate bus voltages. Future research will investigate this assumption based on further measurement data and potentially on actual Smart Meter data.

In conclusion, the use of aggregated smart meter data could be a cost effective way to significantly improve the ability of a network operator to determine a complete picture of the power flows in their distribution grids if they only possess a small number of measurement points.

To implement and validate a secured standardised distributed measurement system in LV microgrids and address the impact of security measures in the measurement system on the metrological requirements and uncertainties

Sensor networks are required to be installed for the smart grid at the LV level to provide the necessary information for grid observation and control. A large amount of measurement and control data are transmitted via various networking technologies and through different communication paths. Missing appropriate security measures are the reasons for high risks of data losses caused by cyber-attack.

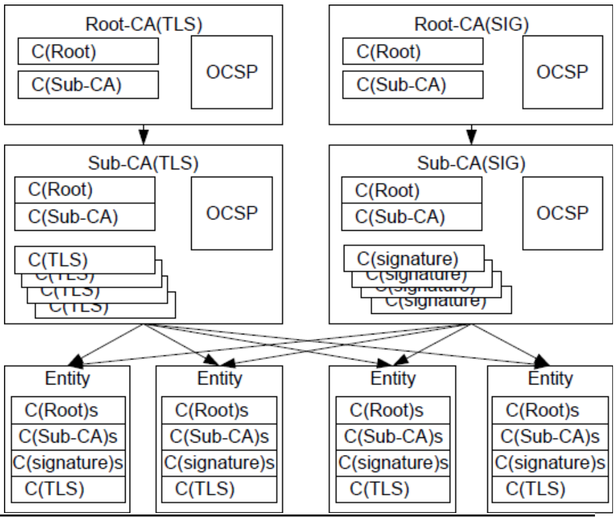
Therefore, a generic end-to-end security concept was developed, which accounted for the main security objectives such as confidentiality and integrity of data. For metrology the security objectives, non-repudiation as well as authentication, are very important and were also included in the security concept.

A second activity concerned the feasibility of the concept. Under this objective, different standards and guidance were analysed in order to find appropriate application layer protocols that can suit the security concept. A common electric power meter was selected and retrofitted with a cryptographic component to provide secured data communication. Then, the whole experimental secured measurement system was implemented.

The third activity concerned that this work feeds into the European standardization process for smart grids, which are beginning to take dynamic control systems into account. The observation and control of LV microgrids requires highly dynamic measurements. Accurate information about latency and reaction time for each end-to-end communication relation is one of the most important issues for grid stability. The influence of the security measures on the time taken to process and communicate data were investigated and the numerical results were represented.

Secured measurement system

Based on the security concept, a prototype for the secured measurement system has been developed and implemented. A core element of this system is a classical hierarchic public key infrastructure (PKI) with its trustworthy root. The implemented architecture of the PKI as shown in the right-side figure consists of two separate X.509 Root-CAs (Certificate Authorities) as the most trustworthy instance, two separate X.509 Sub-CAs. One Sub-CA issues certificates for Transport Layer Security (TLS) connection, another issues certificates for securing the measurement data offering long-term service (e.g. billing). The revocation status of the applied certificates can be verified via Online Certificate Status Protocol (OCSP). Considering the proposition of the technical guidance TR-03116 the applied signature algorithms and curve parameters for CAs are stated in the right-side table. Meter and data acquisition system (DAS) store their own certificates for TLS. During a TLS handshake, the meter sends its certificate to the DAS and vice versa. In contrast to the certificates used for TLS, the certificates used for the signatures, which contain the public key for verifying the signature of the received data on the application layer, will not be exchanged between the meter and the DAS during data communication. More precisely, the meter's signature certificate is installed in the DAS and vice versa.



CA	Signature algorithm	EC parameter
Root-CA	ecdsa-with-SHA384	P-384
Sub-CAs	ecdsa-with-SHA256	P-256

Figure 18: Implemented PKI architecture

Most of the existing meters have none of the required security measures. PTB proposed a retrofitting plan for a meter as shown in the right-side figure. The meter is combined with an embedded Linux board. The cryptographic unit offers asymmetric cryptographic unit offers asymmetric cryptographic algorithm to generate digital signatures for security features on the application layer. The display is used for local monitoring. Two different embedded Linux boards were selected: one with 700 MHz one core CPU and another with 1 GHz dual core CPU.

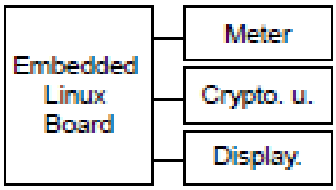


Figure 19: Schematic of retrofitted meter

Various standards and guidance are provided for power grid such as IEC 61850, IEC 62351, IEC 62056 DLMS/COSEM (Device Language Message Specification/Companion Specification for Energy Metering), technical guidance TR-03109-1 for Smart Meter Gateway, Signing Hypertext Transfer Protocol (HTTP) Messages and Extensible Markup Language (XML) security. After investigation of above protocols, DLMS/COSEM, Signing HTTP Messages and XML Security can provide data authenticity and integrity on the application layer for the end-to-end communication. On the retrofitted meter two applications were implemented:

- DLMS/COSEM: An experimental version of DLMS/COSEM logical referencing system. Two COSEM interface classes are used to present the measurement data: one is the interface class Register, which is not protected by any security features; another is the interface class Signed General Data, which provides measurement data with related digital signature.
- Web Service: Considering the technical guidance TR-03109-1, Representational State Transfer (RESTful) web services were implemented. In these, access to measurement data is mapped to RESTful verbs and Uniform Resource Identifiers (URIs). Furthermore, the measurement data type and structure is mapped to XML. The XML file is enhanced with XML signature protection.

Only by using appropriate cipher suites of Transport Layer Security can provide required security level. Considering forward security, authentication, has function, encryption, Message Authentication Code (MAC) and recommendations from different institutes the suitable cipher suites are selected as shown in the right-side table.

Key exchange	Signature	Encryption	Hash
(C1)TLS_ECDHE_	ECDSA_	WITH_AES_128_CBC_	SHA256
(C2)TLS_ECDHE_	ECDSA_	WITH_AES_256_CBC_	SHA384
(C3)TLS_ECDHE_	ECDSA_	WITH_AES_128_GCM_	SHA256
(C4)TLS_ECDHE_	ECDSA_	WITH_AES_256_GCM_	SHA384

Table 1: Selected cipher suites

Performance of the secured measurement system

One of the main aims of this work was to evaluate the performance of the implemented measurement system and to examine whether by applying security measures we can still achieve the performance requirements of the smart grid or not. PTB configured a laboratory test environment, where the meters, the DAS and the OCSP responder could communicate with each other in a local network. Meanwhile PTB also cooperated with TUC installed the meters in the test micro grid at the Energy Research Center Niedersachsen (EFZN), at which the end entities could communicate with each other via Internet.

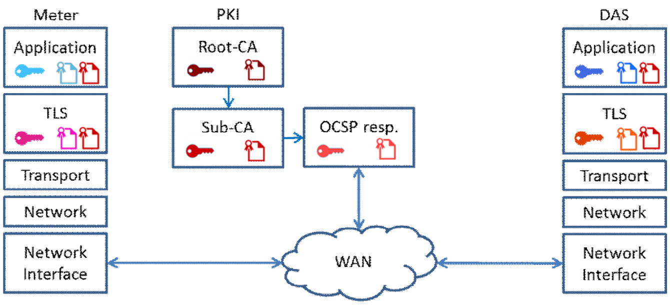


Figure 20: Diagram of secured measurement system showing protocol layers and associated security

The performance assessment processes were identical at the laboratory and field testing environments such as:

- The time taken of the Transmission Control Protocol (TCP) handshake containing one round trip.
- The time taken of the successful TLS handshake. For the key exchange during the TLS handshake different temporal EC domain parameters such as P-256, P-384, and P-521 were used for the calculation of Diffie-Hellman parameters. The meter and the DAS would identify each other. The full TLS certificate chain was set to be verified.
- The time taken of the OCSP processes. These were measured by the meter and the DAS.
- The time taken of the data communication. This comprises an un-protected data communication and secured communication with different security measures such the signature generation via smart card or software, as well as TLS communication with different cipher suites.

The results of all above described tests are stated in the following tables. HW A indicates the board with 700 MHz CPU and HW B indicates the board with 1 GHz dual-core CPU.

LATENCY OF CONNECTION ESTABLISHMENT IN LABORATORY.

Process	Symbol	Latency HW A [ms]	Latency HW B [ms]
TCP HS	t_{TCP_hs}	1.1	0.9
TLS HS P-256	t_{TLS_hs}	125.6	68.8
TLS HS P-384	—"—	157.3	90.7
TLS HS P-521	—"—	221.8	128.5
OCSP (meter)	t_{OCSP_m}	92.2	38.6
OCSP (client)	t_{OCSP_c}	23.9	23.9
TLS SR	t_{TLS_sr}	21.4	6.7

LATENCY OF CONNECTION ESTABLISHMENT IN THE FIELD.

Process	Symbol	Latency HW A [ms]	Latency HW B [ms]
TCP HS	t_{TCP_hs}	12.3	11.4
TLS HS P-256	t_{TLS_hs}	143.7	83.7
TLS HS P-384	—"—	178.4	107.4
TLS HS P-521	—"—	248.2	150.3
OCSP (meter)	t_{OCSP_m}	103.4	43.2
OCSP (client)	t_{OCSP_c}	23.9	23.9
TLS SR	t_{TLS_sr}	25.6	9.7

Latency of one request with a DLMS/COSEM server in the laboratory.

Signature	Cipher	Latency HW A [ms]	Latency HW B [ms]
None	None	4.9	4.6
SC P-192	C1	271.2	251.4
—"—	C2	272.1	253.6
—"—	C3	270.6	251.3
—"—	C4	271.3	251.1
SW P-256	C1	38.8	22.2
—"—	C2	38.2	26.3
—"—	C3	37.1	23.8
—"—	C4	37.7	23.1

Latency of one request with a DLMS/COSEM server in the field.

Signature	Cipher	Latency HW A [ms]	Latency HW B [ms]
None	None	14.2	13.8
SC P-192	C1	281.6	259.7
—"—	C2	281.3	261.2
—"—	C3	279.3	259.6
—"—	C4	280.3	260.2
SW P-256	C1	45.9	27.7
—"—	C2	45.2	31.7
—"—	C3	46.7	28.8
—"—	C4	44.7	28.0

Latency of one request with a web service in the laboratory.

Signature	Cipher	Latency HW A [ms]	Latency HW B [ms]
None	None	480.5	127.9
SC P-192	C1	766.4	389.0
—"—	C2	768.7	393.4
—"—	C3	766.3	392.4
—"—	C4	777.6	391.7
SW P-256	C1	514.1	149.7
—"—	C2	516.8	150.5
—"—	C3	515.3	150.6
—"—	C4	516.5	149.8

Latency of one request with a web service in the field.

Signature	Cipher	Latency HW A [ms]	Latency HW B [ms]
None	None	492.3	136.4
SC P-192	C1	778.3	400.3
—"—	C2	780.1	402.8
—"—	C3	779.6	401.4
—"—	C4	778.3	401.8
SW P-256	C1	526.9	157.3
—"—	C2	528.3	158.2
—"—	C3	527.4	159.0
—"—	C4	527.6	157.8

Table 2: Latency of various data communication methods and security measures

As can be seen from the results, the time taken for most processes is increased during the field testing due to the fact that all data has to be routed through the Internet. Overall, the time taken to establish a secured connection in the field is increased to 259.4 ms for Hardware A and 138.3 ms for Hardware B. Then, the timing behaviour of all important processes in different use cases was assessed. The results showed that the prototype of the secured measurement system could satisfy most performance requirements of various LV grid applications.

Proposal for measurement strategy

The timing behaviour of the secured measurement system were useful and led a better understanding how to schedule the security processes and measurement routines. A generic proposal for an optimised measurement strategy based on secured measurement and communication has been developed, while concerning the impact of time constraints of measurements on the selection of the security measures.
In conclusion, the project has demonstrated a successful implementation of a secure communication system that can be used for protection of SmartGrids against cyber threats. The project has also led to the creation of a European facility to test other implementations of possible security measures.

Effective cooperation between JP-Partners

Much of the work in the project was collaborative and effective cooperation between the project partners was essential to its success. A summary of some of the joint working that took place on the project is given below, grouped by objective.

To develop and test sensor network metrology algorithms for static and dynamic state estimation and optimal sensor placement. The algorithms will be applied to actual LV and MV grids.

- NPL and REG(STRAT) worked together to instrument and configure the PNDC and extend it with the

RTDS system. REG(STRAT) then provided data from the system to enable the testing of the sensor placement and state estimation algorithms developed by NPL. The data was also used by PTB to test the NLO after PTB informed REG(STRAT) of the testing requirements and they collaborated in the analysis of the results.

- REG(TU-E) and PTB used data from the Alliander LiveLab to assess the ability of state estimation techniques to improve its control system.
- NPL and PTB collaborated with VSL, SMU, TUBITAK, FFII, CIRCE and grid operators ENDURIS, ZSDIS, SEDAS and ENDESA to process grid measurement data and apply and test the algorithms developed by NPL and PTB. Close links between each partner and a grid operator from their country were crucial to this work and interaction between these partners and NPL and PTB was essential.
- REG(TU-E), PTB and TUC collaborated to produce realistic models of renewable generation, incorporating weather forecast data to improve the accuracy of measurement estimates used in the application of the NLO to grid data.
- Several joint deliverable reports were written, with contributions from NPL, PTB, TUC, REG(STRAT) and REG(TU-E)

To investigate the use of Phasor Measurement Units (PMUs) for power flow calculation and state estimation in LV grids.

- REG(TU-E), PTB and TUC determined accuracy requirements for PMUs to be used for distribution grid monitoring by applying the NLO to PMU data and assessing its sensitivity to PMU accuracy on typical distribution grids.
- VSL, NPL and PTB also collaborated on the assessing the influence of PMUs in distribution grid monitoring on state estimation techniques. VSL liaised with ENDESA to provide information about the grid data being used to test the algorithms. The partners contributed to deliverable reports on this work.

To determine uncertain distribution network topologies and line impedances and verify existing grid models using a series of on-site measurements and state estimation techniques

- NPL and REG(STRAT) implemented topology estimation algorithms from the literature and worked together to develop them further and compare their performance. Simulations and the PNDC network were used to test the algorithms and a co-authored paper on this work [16] has been submitted to a journal.

To apply Smart Meter data to network state estimation. This will involve investigating how low accuracy Smart Meter data can be aggregated to provide a similar or greater level of understanding of the grid state as measurements made at nodal points in distribution grids

- VSL and REG(TU-E) worked very closely on the development and testing of a smart meter data aggregation algorithm to enable smart meter data to be used for distribution grid monitoring. NPL provided advice on the requirements of the algorithm. This work led to conference and journal papers co-authored by VSL and REG(TU-E) [20][21].
- PTB, VSL and REG(TU-E) collaborated to assess the use of smart meter data for distribution grid state estimation using the NLO. NPL also participated to assess the influence of smart meter data on static state estimation and all partners contributed to a report detailing this work. VSL and REG(TU-E) advised on the use of their smart meter data aggregation algorithm and PTB and NPL ran tests to determine the improvements in state estimation accuracy that can be achieved with smart meter data.

To implement and validate a secured standardised distributed measurement system in LV micrgrids and address the impact of security measures in the measurement system on the metrological requirements and uncertainties

- PTB and TUC collaborated to produce a secure measurement system that could be used for monitoring LV microgrids.
- PTB and TUC worked together to configure and operate a micro-grid at TUC and to install and test

the secure measurement system on the grid.

Summary of Projects Key Results and Conclusions

The project brought together partners with a wide range of expertise in electrical power engineering, measurement science and mathematics. The unique challenges presented by the project could only be overcome with such combined expertise. A thorough understanding of electrical power grids, grid modelling and power flow analysis provided by universities and grid operators was required to enable the mathematicians from NMIs and universities to develop and apply algorithms for state estimation and optimal sensor placement. An understanding of the instrumentation used for grid monitoring, assessments of the impact of such equipment and the use of the algorithms on the accuracy of power flow calculations could only be achieved with a sound metrological background provided by the partner NMIs. In addition, facilities provided by the grid operators and consortium were vital for the development and validation of the algorithms.

The key results and conclusions from the research carried out in this project are given below. The methods described are now available to grid operators and other researchers to enable a greater understanding of electrical power grids and their future development.

- New method for quasi-dynamic state estimation for unbalanced three-phase three-wire electrical distribution grids with incomplete infrastructure, taking into account PMU and Smart Meter data.
- A fast state estimation method based on Burer Monteiro factorisation was developed. This was tested on real grids and was shown to have greater accuracy and faster computation time than other techniques.
- Several sensor placement algorithms were developed and tested on the PNDC and with real grid data from distribution grids. The algorithms were shown to give improved errors in the state estimation results when limited real measurements are available.
- Assessments of the improvements that can be made in distribution grid monitoring when PMUs are used were made for a range of distribution grid types and sizes with different measurement strategies. These can be used to provide estimates of the accuracy requirements of PMUs for such monitoring.
- The use of PMUs for distribution grid monitoring was assessed on a number of real grids using the NLO and static state estimation techniques. The NLO was applied to the PMU data from the ENDURIS grid and the performance was shown to improve as the number of PMUs was increased. Static state estimators were applied to a number of real grids and the PNDC and the reduction in overall uncertainty of the state estimation was plotted against number of PMUs to illustrate how the addition of PMUs can be used to improve the estimates. Similar techniques can be applied to any grids to determine whether PMUs in those networks are worthwhile for a given budget.
- Topology estimation algorithms were implemented and refined before being tested on the PNDC and with real grid data and were found to be effective at recovering unknown connections in a number of networks. Topology estimation is an extremely challenging problem and successful testing of such algorithms is an important addition to the current state of the art.
- State estimation methods and sensor placement algorithms were developed to take into account uncertain line impedances, which are usually treated as known parameters in state estimation. The algorithms can also be used to determine unknown line impedances.
- Simulations in combination with real smart meter data show that a reliable MV nodal power for the use of DSSE can be obtained in terms of a mean value with an uncertainty. The calculated accuracy level of the aggregated data is less than that of the individual smart meter (0.5 % to 2 %), but better than the hypothesis (10 %) used in existing literature. Compared to pseudo-measurements with a maximum error around 30 % - 50 %, the advantage of the utilization of smart meter data in DSSE is obvious.
- The impact of using aggregated smart meter data on the estimated states of two three-phase MV distribution networks has been investigated by simulations, comparing with data from traditional

meters and pseudo-measurements. The accuracy level of the data is found to be of great importance on the estimation results, especially when extra measurements are hardly available. Our results can be very valuable for network operators for improved planning and operation in MV distribution networks, for example by improved Volt/VAR optimization, network reconfiguration and demand response.

- In the project, a Public Key Infrastructure (PKI) was set up, which can be used for various applications of secure data exchange. The scope of application can be extended to all areas of electronic digital signatures. The NMIs can occur here in the role of trust anchors (trustworthy partner).
- A test environment has been established for determining the dynamic parameters of secured data communication under real conditions.
- Feasible solutions have been provided on how to modernize conventional meters with additional security devices.

4 Actual and potential impact

Metrology Achievements

The main metrology achievements of the project are in the area of sensor networks. This is a growing area of metrology, which is the use of measurement information from multiple sources to provide information about the state of a system. In the case of this project the state refers to nodal voltages and power flows in distribution networks. Significant contributions were made to three main fields in this area. These are state estimation, sensor placement and smart meter data aggregation.

State estimation

Improvements to the NLO state estimation technique described above included the incorporation of uncertain network parameters and three phase network data and a thorough treatment of the resulting uncertainties. All network parameters are now included, which was not the case with previous versions of the algorithm or of many commonly used state estimators. Such treatment allows a greater range of grids to be analysed and the demonstrated use of the algorithm in real distribution grids gives confidence that the method can be practically applied by network operators. The treatment of the uncertainties in the Kalman filter, which was part of this work, can be applied to other branches of metrology where similar techniques are used and a paper [22] has been published.

A new fast state estimation algorithm was also developed, which uses optimisation techniques to reduce the uncertainties in the final solution. For some grids this reduced the overall mean squared error in the solution by up to a factor of 5. Such techniques can be applied to sensor networks and optimisation problems and so have the potential to benefit sensor network metrology outside of electrical power grids. A paper on this work was submitted to a journal [23].

Sensor placement

Several new optimisation techniques using semi-definite programming were applied to find the best configuration of sensors in networks for electrical grid monitoring. Such techniques allow the reduction of uncertainties in the derived quantities of interest at both monitored and unmonitored points by choosing the optimum sensor configuration and using the combined results of multiple sensors. Such work can be applied to a range of sensor networks, including those dealing with derived measurands with non-linear, e.g. quadratic, dependence. Several journal papers on this work are in preparation and the techniques used have been presented at conferences including those aimed at the metrology community [24][25][26].

Smart meter data aggregation

A major goal of the project was to utilise available sources of data to provide improved estimates of distribution grid state. Smart meters, which are installed at the LV level, are one such data source. A new way of utilizing and processing smart meter data for the purpose of the state estimation in MV distribution networks was introduced by VSL and REG(TU-E) and the associated uncertainty due to several identified error sources was calculated. Furthermore, the influence of uncertainty associated with the aggregated smart meter data on the state estimation in MV distribution networks was investigated. A thorough treatment of the uncertainties resulting from these techniques has not been done before. This enabled the influence on monitoring at the MV level to be more thoroughly assessed than ever before. It was shown that lower uncertainties in measurements at the distribution level derived from aggregated smart meter data can be achieved than those typically assumed in the literature – <1 % for class 0.5 smart meters can be achieved compared to assumptions of around 10 % in some cases [18][19].

Dissemination Activities

4.2.1 Scientific publications

The project has generated 9 high impact publications in key journals and 1 is in preparation. These incorporate the significant scientific outputs of the project.

In addition to the scientific publications above, the work was publicised at the end of the project in Smart Grid Today, www.smartgridtoday.com, an online trade journal dedicated to smart grid related topics. The project was also publicised in the Elektor magazine in September 2016. Elektor magazine, www.elektormagazine.com, has an international audience and is published monthly in English and has a mixed readership of professionals and non-professional interested in electronics.

Two new e-training packages and the relevant Good Practice Guides on how to employ them have been produced, they are:

- Best-practice guide for quasi-dynamic state estimation with the Nodal Load Observer (NLO) algorithm.
- A guide on how to employ security algorithms to create a Public Key Infrastructure (PKI).

4.2.2 Conferences and relevant fora

Thirteen oral presentations as well as one poster presentation have been given by the partners during the life time of the project. Positive reactions were received to all these contributions, attracting discussions and comments.

The results were presented at a range of different types of conferences, reflecting the diverse range of expertise on the project and academic and industry stakeholders. Mathematics, metrology and electricity distribution conferences were the most appropriate for the majority of the work.

Major measurement conferences include Conference on Precision Electromagnetic Measurements (CPEM), World Congress of the International Measurement Confederation (IMEKO). Major electricity industry conferences include International Conference & Exhibition on Electricity Distribution (CIRED) and IEEE International Workshop on Applied Measurements for Power Systems (AMPS).

4.2.3 Engagement with Standards Bodies

The consortium has been an active member of the working groups (10) of several relevant standards committees. The security systems developed in this project have been used to inform standardisation bodies on how to achieve a homogenised approach in LV microgrids. Concepts, ideas and results of the measurement security work has been regularly sent to the CEN/CENELEC/ETSI standardisation process under the EU mandate M/490. A report by the committee on the standards requirements for smart grids has been published along with a further document on cyber security [27][28].

In addition, the consortium contributed to a draft standard governing the use of signalling on the mains electricity supply.

4.2.4 Stakeholder Engagement

The project was mainly focussed on the application of state estimation and sensor placement algorithms to real distribution grids and stakeholder involvement was therefore vital. The project used network topology data and measurement data from several network operators (ZSDIS, SEDAS, ENDURIS, ENDESA and Alliander), which required significant effort on their part both to gather the information and to assist in its conversion to forms that could be used with the developed algorithms. The ongoing results from implementing the algorithms on this data demonstrated that the algorithms could be applied for future planning and operation of their grids.

Further interaction was necessary for the investigations into the use of PMUs and smart meter data for distribution grid monitoring. VSL, REG(TU-D) and REG(TU-E) worked very closely with ENDURIS to instrument the 50 kV part of their grid with PMUs and then to gather the data from this sensor network and the already installed SCADA system. The analysis carried out on the data enables ENDURIS to understand the power flows in their grid and allows them to make decisions about the further use of PMUs in their networks.

The gathering of smart meter data was a very difficult part of the project as privacy issues prevented network operators from disclosing the locations of any data they had. REG(TU-E) worked with Alliander to gather anonymised data from several locations and taken under a range of network conditions. This could then be used to provide realistic data that was used to test the smart meter aggregation and state estimation methods. This enabled an appraisal of the use of smart meter data for distribution grid monitoring, which demonstrated that such data can be very valuable to network operators, potential improving the accuracy of their power flow calculations.

4.2.5 Workshops

Two workshops were held by the consortium. A mid-project workshop was held at the University of Strathclyde, UK in association with a Researcher Excellence Grant (REG(STRAT). The workshop was attended by 40 attendees from NMIs, industry and academia. This was also a joint workshop with ENG52 Smart Grid II.

The second workshop, at the end of the project, was held in Haarlem NL and was attended by more than 70 attendees from NMIs, industry and academia. This was a combined workshop of all the EURAMET projects on Electricity Grids finishing in 2017 (ENG61 FutureGrid & ENG52 Smart Grid II and ENG63 GridSens) and was attended by stakeholders.

Early Impact

4.4.1 Standards and regulation:

The security systems developed in this project were used to inform them of how to achieve a homogenised approach in LV microgrids, which are small self-contained networks capable of operating independently of the wider grid and are becoming more important as local renewable generation increases. Information and results of the measurement security work has been regularly sent to the CEN/CENELEC/ETSI standardisation process under the EU mandate M/490. A report by the committee on the standards requirements for smart grids has been published along with a further document on cyber security:

ftp://ftp.cencenelec.eu/EN/EuropeanStandardization/Fields/EnergySustainability/SmartGrid/SmartGridSetOfStandards.pdf

ftp://ftp.cencenelec.eu/EN/EuropeanStandardization/Fields/EnergySustainability/SmartGrid/CyberSecurity-Privacy-Report.pdf

In addition, the consortium contributed to IEC SC77A WG1 on a draft standard governing the use of signalling on the mains electricity supply.

4.4.2 User uptake:

Most of the work in the project was focussed on the application of algorithms to real distribution grids, which required continued engagement with network operators throughout Europe, who are perhaps the most important end users of the project outputs. The consortium's findings are now available to them and as a result of the close cooperation can be easily employed. The results of the project have also been presented at several industry relevant events and conferences in addition to publication in appropriate journals. Other users of the work include the mathematical community, academics and other NMIs, all of whom have been informed of the project outputs through seminars, publications and collaboration on a number of publications.

4.4.3 Actual impact

Actual impact

The project was predominantly focussed on the application of algorithms to real distribution grids, which required continued engagement with network operators throughout Europe, who are the most important end users of the project outputs. The consortium's findings are now available to them and, as a result of the close cooperation, can be easily used by them.

This project will enable network operators to improve their systems by:

Providing a validated Dynamic State Estimation algorithm, the NLO that is able to provide an accurate picture of the grid state in real time.

Providing robust validated sensor placement algorithms that not only take relevant uncertainties into account but also budgetary considerations.

The demonstration that PMUs (an advanced and relatively expensive type of sensor) can successfully be used in a cost effective manner to significantly improve estimates of grid state and therefore the ability of network operators to control their distribution grids.

Providing validated algorithms that allow network operators to recover missing grid topology (line impedance and connection) information.

Demonstrating that aggregated smart meter data can be used to improve the ability of a network operator to determine the state of their distribution grids if they possess a small number of measurement points.

Demonstrating that PKI secures sensor network systems used for grid monitoring from cyber-attack.

Providing a European test facility suitable for characterising security measures on LV microgrids.

Potential Impact

The state estimation and sensor placement algorithms developed in the project have now been validated with real data and are ready for use with grid monitoring systems allowing the initial aims of the project to be fulfilled. The optimal sensor placement algorithms will allow grid operators to minimise the measurement equipment installed on their networks, resulting in reduced operating costs, which will have a knock on effect on consumers.

The state estimation algorithms will allow a greater understanding of the power flows in distribution grids improving the planning and operation of future grids, enabling them to function more efficiently and therefore have a positive environmental impact.

The testing with real data proves the use of the algorithms in real systems can lead to a greater understanding of distribution networks. This encourages their timely uptake by giving grid operators confidence in their efficacy.

Smart meter data aggregation algorithms and the incorporation of PMUs in state estimation will enable the effective use of PMUs and smart meter data in distribution grid monitoring, giving a greater understanding of the networks and again leading to improved planning and operation. This can lead to a greater uptake of renewable generation and smart grid technologies including demand side management. Again this evolution of the electricity supply leads to obvious environmental, societal and economic impact.

The development and practical demonstration of security measures will lead to increased security and confidence enabling smarter grids, this includes the integration of innovations in demand side management and allows greater interaction between smart grid components. It is essential that the performance of energy management systems is not compromised by the addition of security measures. The assessment of the impact of security measures on distributed measurement systems ensures that such energy management systems still operate efficiently without being unduly influenced by the security methods. This will increase consumer confidence and enable the adoption of more smart-grid technologies, again increasing the use of low carbon generation and allowing a more financially viable grid with greater commercial opportunities.

5 Website address and contact details

A public website has been open where the end users were kept them informed about project meetings and events: www.gridsens.eu/

The contact person for general questions about the project is Paul Clarkson, NPL, Paul.Clarkson@npl.co.uk

The contact person for the cyber security work is Yiyang Su, yiyang.su@ptb.de

6 List of publications

On The Evaluation Of Uncertainties For State Estimation With The Kalman Filter S Eichstädt, N Makarava, C Elster IOP Measurement Science and Technology Vol. 26 (2016)

Uncertainty Analysis of Aggregated Smart Meter Data for State Estimation F Ni, P H Nguyen, J F G Cobben, H E van den Brom, D Zhao, 2016 IEEE International Workshop on Applied Measurements for Power Systems (AMPS) Proceedings, Aachen, Germany, pp. 13-18 (2016)

Enhancing Prony's Method By Nuclear Norm Penalization And Extension To Missing Data S Chetien, Signal, Image and Video Processing Vol 11, Issue 6, pp 1089–1096 (2017)

On The Pinning Controllability Of Complex Networks Using Perturbation Theory Of Extreme Singular Values - Application to Synchronisation In Power Grids S Chretien, S Darses, C Guyeux, P Clarkson, Numerical Algebra, Control and Optimisation (2017)

Methodology For Testing Parameter-Free Fault Locator For Transmission Lines M Popov S Parmar, G Rietveld, G Preston, Z Radojevic, V Terzija Electric Power Systems Research (2016)

Basis-Adaptive Sparse Polynomial Chaos Expansion For Probabilistic Power Flow F Ni, P H Nguyen, J F G. Cobben, IEEE Transactions on Power Systems, Vol 32, No. 1 (2017)

Pmu-Based Power System Analysis of A MV Distribution Grid N Save, M Popov, A Jongepier, G Rietveld, Proceedings of CIRED 2017 (2017)

Application Of Non-Intrusive Polynomial Chaos Expansion In Probabilistic Power Flow With Truncated Random Variables F Ni, P H Nguyen, J F G Cobben, Probabilistic Methods Applied to Power Systems (PMAPS) (2016)

Measurement of the Harmonic Impedance of the Aggregated Distribution Network V Cuk, F Ni, W Jin, A Jongepier, H E van den Broom, G Rietveld, M Acanski, J F G Cobben, ICHQP 2016, Belo Horizonte, Brazil, pp 739 – 744 (2016)

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