HiPerDNO

High Performance Computing Technologies for Smart Distribution Network Operation

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Executive Summary

This working paper gathers information on the existing and future deployment of sensors and measurements in partner DNOs which are relevant to the HiPerDNO objectives, particularly the off-line field trials in WP4. The paper first discusses the properties of the relevant sensor types. The present status of measurements systems in the three partner DNOs is then described, together with known plans for roll-out of existing sensor types and any plans for introduction of new technology. The information in this section of the paper is based on completed survey questionnaires (included as appendices) which were provided by all three partner DNOs. Issues for cost-effectiveness and probable business justifications associated with future deployments of sensors and measurements are then discussed here in general terms. Some consideration is then given of the best locations for new sensors. Relevant standards for sensors, communications and interoperability are then discussed. The working paper then concludes with some proposals for future strategies for sensor and measurement deployment.

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Abstract	This working paper gathers information on the existing and future deployment of sensors and measurements in partner DNOs, relevant to the HiPerDNO objectives, particularly the off-line field trials in WP4. The paper first discusses the properties of the relevant sensor types. The present status of measurements systems in the three partner DNOs is then discussed, together with known plans for roll-out of existing sensor types and any plans for introduction of new technology. Issues for cost-effectiveness and business justifications associated with future deployments of sensors and measurements are discussed here in general terms. Some consideration is given to the best locations for new sensors. Relevant standards for sensors,			

	communications and interoperability are discussed.
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Contents

Introduction

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Sensor and Instrumentation Types

The sensor and instrumentation types considered in this working paper will be considered in three groups: direct electrical network quantities, measurements related to condition monitoring and other types of measurement (e.g. at weather stations).

Electrical Network Measurements and Sensors

Breaker Status Sensors

For remote control of the distribution network (via SCADA), and to allow any network model based application such as state estimation to function, it is necessary to monitor the open/closed status of circuit-breakers and relevant isolators. Accuracy is normally increased by having two status indicators for each breaker –one indicating that the breaker as been commanded to close (or open) and a second indicating that it has closed (or opened). These two indications can disagree during the operation of the breaker, but in steady state must agree for the status to be valid. The breaker status indication should be time-stamped so that a consistent network topology model can be maintained.

Transformer Tap Position

Transformers which have on-load tap changing capabilities introduce a new variable into the understanding or modelling of a distribution network, namely the off-nominal tap ratio. It is possible to measure the tap position, which takes on an integer value between 0 and up to about 30 (depending n the number of discrete tap positions provided). In a state estimation problem the tap ratio can be regarded as a parameter of the model, or in some implementations as an additional state variable. If the tap position is measured and telemetered through the SCADA system, then there is no difficulty in modelling. Where P, Q and V measurements are made at the primary side of variable tap transformer then the transformer ratio must be measured, or somehow known, to give a fully accurate model [1].

Voltage Magnitude

The voltage in a distribution network should be sinusoidal and for each of the three phases is displaced by 120 degrees. Voltage magnitude refers to the r.m.s. value of the sinusoid (usually for one phase only). Lack of an accurate time signal precluded the measurement of phase angle in traditional measurement systems (but see later regarding phasor measurements). Sensors are provided to measure a relatively low voltage only, and so a voltage transformer (VT) is used to connect the sensor to the distribution busbar or terminal. The limited accuracy of the VT often determines the overall accuracy of the measurement and a $\pm$1% error is typically quoted. In power system engineering it is common to express electrical quantities as 'per unit' which is a normalisation of the value relative to its 'nominal' or 'rated' value. So for example a measurement of 34.65kV in a 33kV network would be referred to as (34.65/33) = 1.05 pu. Since voltage magnitudes in a distribution network should not vary by more than a statutory limit (often $\pm$ 5%) we can see that measuring the voltage magnitude to within $\pm$1% is essentially of quite limited precision. Time stamping of voltage and other analogue measurements is important so that a consistent set of measurements can be assembled for state estimation and other modelling purposes. Experience in WP2 [1, 2] has shown that voltage magnitude measurements are only of limited value for state estimation purposes. The sensitivity of real and reactive power flows to the nodal voltage magnitudes is such that it is relatively easy to estimate the voltages (magnitudes and phase angles) based on reasonably accurate measurements of active power (P) and reactive power (Q). Calculation of accurate flow and injection estimates based on voltage magnitude measurements would necessitate unrealistically accurate voltage magnitude measurements.

Current Magnitude

Current magnitude is often measured in distribution systems. The current carried by cables, lines and transformers is responsible for their temperature rise, due to Ohmic heating, or 'copper loss', and must be limited to avoid damage. Secondly, since the voltage magnitude is approximately constant ($\pm$ 5%) the current gives a good indication of the 'load' on a network (P = V.I.Cosθ). Traditional distribution networks operated in a top-down fashion and it was obvious which direction the energy was flowing. Active distribution networks with embedded generation may experience flow reversal and in this case the current magnitude measurement is less useful as no indication is given of the direction of power flow.

Current magnitudes are measured via current transformers (CTs) and have similar accuracy to voltage magnitudes ($\pm$ 1%)

Active and Reactive Power

Where voltage magnitude and current magnitude sensors are co-located, it is possible with simple electronics to combine the two, along with a measured phase-difference between them, to obtain measurements of active power (P) and reactive power (Q). The additional electronics represents some additional cost, however P and Q measurements are much more suitable for state estimation purposes and are being progressively introduced by DNOs.

Phasor Measurements

By using highly accurate GPS-based timing information it has become possible to measure the relative phase angles of voltages and currents across the geographically dispersed area of a distribution network. Such Phasor Measurement units are commercially available from a number of manufactures and are relatively inexpensive. Brunel University is presently installing a PMU for research and teaching purposes. The major cost of PMUs is installation (labour).

Having accurate values of voltage and current phasors (together with the power system frequency) is very useful for monitoring the network state (e.g. via state estimation) and can allow dynamic network disturbances to be identified.

Condition Monitoring Measurements and Sensors

Partial Discharge Sensors

Partial discharges (PDs) are minute electrical sparks caused by the ionisation of gas within voids or on the surface of dielectrics and conductors [3]. PD has been widely accepted as the primary cause of long term degradation of electrical insulation. UKPN applies on-line PD monitoring technology on its MV networks extensively, where more than 70 substations are equipped with the advance substation monitoring (ASM) system developed by IPEC Ltd. Depending on the types of PD activities, different PD sensors can be used to detect different PD signals. The three different types of PD sensors used in the ASM system are introduced as follows:

(1) High Frequency Current Transformer (HFCT) Sensors

PD activity in HV insulation induces small high frequency currents in the earth conductor of the electrical system. These pulses travel along the equipment earth to the substation earth. Using a high frequency current transformer the pulses can be detected. The HFCT sensor has a split core ferrite to allow retrospective fitting to earth straps without the need for disconnection. For example, when a PD event occurs somewhere along the cable, the high frequency current pulses travel, in both directions, from the defect towards the cable ends. As show in Figure 1, the sensors are attached to the earth strap of the cables in the primary substations to pick up the PD pulses.

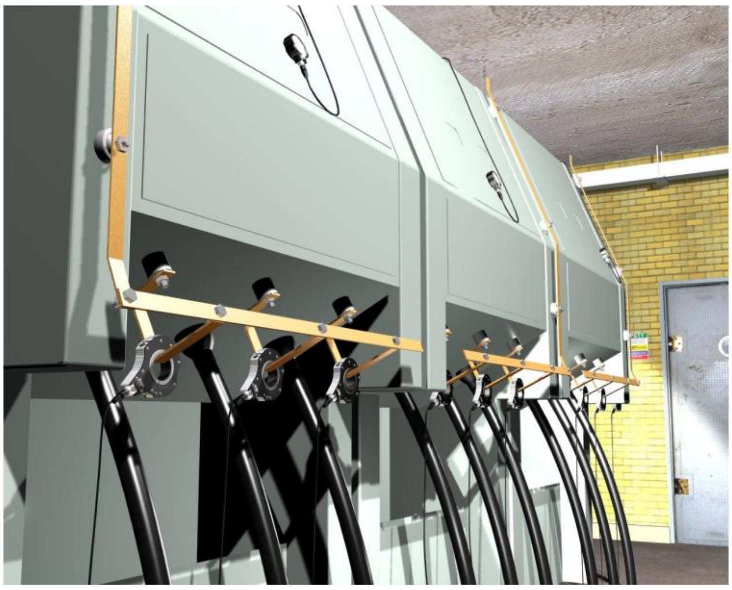

Figure 1. HFCT sensors attached to the earth of the cables in substation. (Courtesy of IPEC)

(2) Capacitive Coupler (CC) Sensors

This type of sensor is used to detect local PD activity. Here the term 'local' means PD within the metal-clad equipment under observation, for example, PD occurring within switchgear. The PD activity within metal clad HV equipment can radiate electromagnetic (EM) energy in the range of radio frequency waves and infra-red (IR). IR cameras can be used to detect infra-red signals. As shown in Figure 2, the RF signals travel through insulating materials. While most of the EM energy is conducted away by the surrounding metal casing, a small amount of RF impinges onto the inner surface of the metal cladding. These small changes escape through the joints in the metal casing and induce the transient earth voltage (TEV) on the earthed metal cladding. The CC sensors are essentially small RF antennas which can be used to detect such high frequency signals. The sensor is enclosed in a durable silicon body which has powerful magnets embedded within for mechanical coupling to metal enclosures. Figure 3 shows the fitting of CC sensors in a substation.

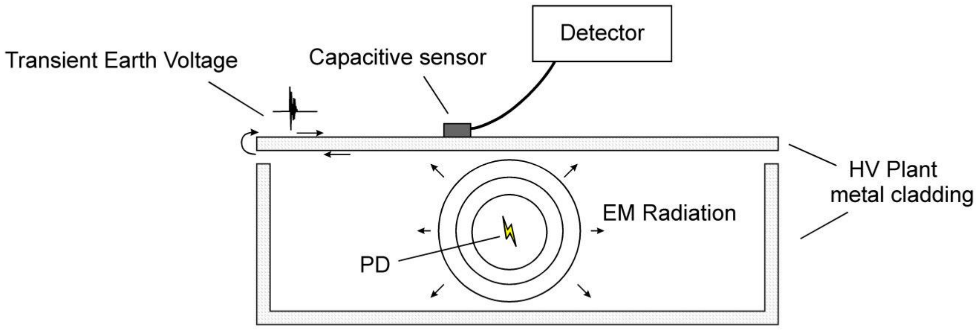

Figure 2. Transient Earth Voltage (TEV) detection [4].

Figure 3. CC sensors attached to the outside of the metal casing of the HV plant. (Courtesy of IPEC)

(3) Airborne Acoustic (AA) Sensors

Corona in air and surface tracking activity generates acoustic emission. Acoustic PD sensors are used to detect acoustic energy emitted into the air by PD activities at the surface of busbar sections, boxes, etc inside the switchgear casing. The acoustic probe is designed for use on air insulated assets where there is a clear sound path between the insulation and the AA probe. In Figure 4, the AA sensor is attached magnetically on the inside of the metal cabinet of the switchgear.

Figure 4. AA sensors attached to the inside of the metal casing of the HV plant. (Courtesy of IPEC)

Transformer Temperature

Failure of transformers is generally caused by overheating, ultimately causing the failure of insulating material and a consequent short-circuit. Measurement of transformer temperature (and other factors such as on-line analysis of gaseous products in the insulating oil) can indicate the risk of failure in transformers which are operating close to their limits.

Other Measurements and Sensors

Weather Information

Weather information is important to DNOs for various reasons. The weather strongly influences the load (peak loads are associated with cold weather in winter and hot weather in summer). Storm conditions can lead to faulting of overhead lines. Power input to the network from renewables, such as photo-voltaic and wind-turbines, is also (of course) highly dependent on the state of the weather.

Present Status and Existing Plans

To gather information for this working paper, a survey questionnaire was designed and distributed to the DNO partners in HiPerDNO, namely, UKPN, EG and UF. Responses were received from all three DNOs and are included in Appendices 1, 2 and 3. The present status and existing plans which have been elicited are discussed below, categorised according to voltage levels (HV, MV and LV), since the structure, technical features and economics of distribution networks are distinct at each voltage level.

HV (110kV and above)

This voltage level (e.g. 132kV in the UKPN and UF) is usually referred to as sub-transmission. For UF, 220kV network information is provided by the TSO (REE). In Slovenia the 110kV system is owned by the TSO, but measurement information is also provided to EG (the DNO).

At the HV (also sometimes referred to as EHV) level, we find 100% coverage (all substation are measured) of measurements of P, Q, |V| and |I|. (Where P refers to active power, Q is reactive power, |V| and |I| are voltage and current magnitudes respectively.)

There is some penetration of other types of measurements: Transformer temperature is measured in UKPN, also gas pressure for SF6 circuit-breakers and weather monitoring at some outdoor substation sites.

PMUs (phasor measurement units) are planned in UKPN. These units measure P, Q, V and I, plus frequency f, but in this case due to the availability of highly accurate time data (via GPS) the voltage and current phase angles are also measured (in addition to the usual magnitudes).

Partial Discharge measurements are available for many cables (especially associated with 132/11/11kV three-winding transformer substations which are becoming more common).

EG plans to introduce the IEC 61850 standard throughout.

MV (1kV to 110kV)

At medium voltage levels, distribution networks are much more extensive and we expect to find partial network coverage, in terms of measurements.

UKPN have |V|, |I|, P, Q and transformer temperature for 66kV and 33kV networks. Partial discharge measurements are being tested for 11kV cables in some primary substations. In distribution substations (usually 11kV) the SCADA RTU monitors |V|, |I|. In the future UKPN plans phasor measurements and partial discharge monitoring throughout, along with P, Q with direction of flow, power factor and Total Harmonic Distortion (THD).

EG have 100% coverage in distribution substation of |V|, |I|, P, and Q. Again, their plan is to introduce IEC 61850 throughout.

UF are installing equipment to measure |V|, |I|, P, and Q in new 15kV and 20kV substations, but in older rural substations (HV/MV) only |V| and |I| are measured. They plan to introduce more remote controlled switches.

LV (below 1kV)

At low voltages (also referred to as the 'mains' network) there is a very large scale network (e.g. including millions of cables) and a great lack of measurements. The anticipated roll-out of smart meters has the potential to add millions of new measurements, provided DNOs have suitable access to this information source.

UKPN presently only have Maximum Demand Indicators (MDI) on each electrical phase. These record the long-term, maximum current and are only read by manually inspection (and hence very infrequently). Plans at UKPN involve smart meters on each LV way/board in distribution substations and measurements from smart link-boxes with remote switching capabilities.

EG have |V|, |I|, P, and Q in about 20% of 20/0.4kV transformer stations based on MI7150 network analysers, but only some of these can be remotely monitored. They plan to achieve 100% coverage in the future including smart meters.

UF have not mentioned any existing measurements at this level. They plan to install |V|, |I|, P, and Q sensors in conjunction with measurement equipment and smart meters.

The LV level is where there is greatest scope for enhancing the observability and control in the future based on smart grid technologies and corresponding ICT infrastructures.

Cost Effectiveness and Business Cases

A business case which gives a full analysis of technical feasibility and cost effectiveness is a pre-requisite for the widespread introduction of any measurement scheme, or sensor type, in a distribution network. The business case should include consideration of 'future proofing', in other words as well as providing an immediate business benefit, it is necessary to show that the deployed sensors and other technology will be flexible enough to satisfy likely future requirements over the next (say) 20 years. Some of the potential business cases for the further deployment of sensors and instrumentation are listed and discussed, in general terms, in the following subsections.

Improved Monitoring via SCADA

Additional sensors will allow greater visibility of the distribution network by SCADA control room staff. For example, in most distribution networks at present it is possible for a fault to occur in a remote part of the network, causing supply outages to customers, but not be visible through the existing SCADA measurements. In this case the DNO must rely on customers contacting them (via telephone, web-site, etc.) to complain. The business case here would be based on improved customer satisfaction and a reduction in customer-minutes lost. The criteria for deployment of sensors and measurements under this heading will be to maximise the visibility of the operating state of the network. This criterion is in line with maximising the applicability of state estimation throughout the DNO network (i.e. maximising the number of substations and feeders which are fully observable and where possible extending the scope of state estimation to progressively lower voltage levels of the network).

Enabling Automation

The introduction of more intelligent control schemes will necessitate extended sensor and measurement deployment. For example, automated switching to isolate a fault requires sensors such as fault passage indicators which can at least detect the occurrence of fault level current and indicate which direction is towards the fault. A difficult task for DNOs is to manage the co-ordination of advanced schemes so that measurements and sensors required and cost-justified for a particular scheme can also provide benefits for other purposes (e.g. state estimation). In some cases two separate business cases may fail the criteria for acceptance but when 'overlapped' the synergy between the two cases may produce a unified business case that is acceptable.

Operation Closer to Constraints

Active distribution networks will operate the network equipment closer to its limitations; a major benefit of active networks is to avoid or defer investment in new cables and transformers. It is not feasible to operate a circuit close to its limits unless accurate monitoring and control is provided to: (a) observe that the limit is being respected and (b) be able to adjust the flow, voltage, etc. so that violations of a limit can be avoided. This business case will generally be a very compelling one; i.e. to operate reliably with an existing circuit (or circuits) and avoid, or defer, the major investment required to build additional circuits. The criterion for deployment of sensors and measurements, in this case, is to maximise the deployment in sections of the network which are operating close to their limits, or which are predicted to do so in the near future. Any segments of network which are earmarked for the introduction of active network and smart grid technology would be clear candidates for enhanced deployment.

Reducing Customer Supply Interruptions

The regulatory regime for most DNOs incorporates penalties for power outrages (customer minutes lost). The Supply Restoration Algorithm (SRA) being developed and tested within HiPerDNO will be a major factor towards minimising the duration of outages, as demonstrated in WP2.3 [5]. The SRA needs a solid network model database to work on, which can only be provided by some form of state estimation. The criterion for measurement deployment here is entirely consistent with maximising the penetration of the state estimation model. The desire to reduce energy outages would suggest that initial deployment of sensors and measurements should concentrate on the higher loaded parts of the network and those parts of the network serving the greatest number of customers.

A large proportion of customer loss of supply events are a results of cable faults. The introduction of partial discharge monitoring in UKPN has already directed refurbishment programmes towards sections of cables that are exhibiting higher, or increasing, partial discharge activity. In such cases, the expert inspection of sections of cable which have been removed has indicated that a fault did appear to be imminent.

Reducing Energy Loss in the Network

Energy lost in distribution networks can be quite significant (usually around 5% to 7% of the total energy input on average). The main prospects for reducing this via operational strategies are to select normally open points optimally (which can be achieved by SRA or a similar algorithm), and to take energy losses into account when looking at smart grid technologies to control embedded generation and intelligently controlled loads. The need to move normally open points in response to faults, and for any other operational purposes, has a significant effect on sensor and measurement deployment. This is an inherently difficult problem, since the operating topology of the network has huge flexibility, i.e. the combination of open points can be selected from an astronomical number of possibilities. The problem here is to avoid deploying meters in positions where they can become 'stranded assets' during some operating states. One simple approach would be to deploy meters near to feeder sources in preference to remoter parts of the network. In this way the meters are still likely to be useful for any choice of open point and for most fault locations.

Enabling Greater Penetration of Renewable Energy Sources

A potential difficulty for a DNO is to envisage a feeder with extensive penetration of embedded generation (e.g. domestic PV) and perhaps intelligent loads (e.g. electric vehicle charging) but lacking in sensors and measurements. This would result in a feeder with potentially difficult voltage excursions and potential current overloads which are not properly visible to the SCADA system. It is natural to assume that the introduction of embedded generation and significant intelligent loads would be accompanied by extended measurement schemes. Again, the deployment of sensors and measurements would go hand-in-hand with smart-grid initiatives.

Optimal Location of Sensors in Distribution Networks

Optimal Location for Effective State Estimation

The selection of measurement types, coverage, and optimal location is more important for state estimation applications than for other general purposes. This has been demonstrated via off-line simulations in deliverables D2.1.1 and D2.1.3 [1, 2].

State estimation depends on the 'observability' of the measurement set. This is a mathematical function of the types and locations of measurements for a particular network topology to be estimated. For existing DNO networks, the number of physical measurements available is very limited (e.g. three physical measurements on a feeder with, say, 50 loads connected) and as a result observability of the state estimation process relies on a large number of pseudo-measurements. However, the overall accuracy may then be dependent on the accuracy of the pseudo-measurements which is expected to be rather poor.

Experience to date suggests that measurements of active and reactive flow (P and Q) have very good information value for state estimation purposes (relative to V and I measurements) [1].

Optimal Location for Condition Monitoring Application

The location of PD sensors depends on the type of assets being monitored. Here we classify the assets into two main groups, i.e., HV equipment and cables/lines. As is shown earlier, to monitor the HV plants located inside the substation, for example, switchgears, PD sensors are attached magnetically to the metal casing of the assets. For the case of underground cables, the nature of being 'under the ground' means that the sensors can only be installed in the terminal ends in primary substations or ring main units (RMUs) since these are physically reachable areas. The location of PD sensors is more flexible for overhead lines and will depend on the detection sensitivity. It is worth mentioning that, in this report, we only consider the location of the sensors at a macro level. That is, sensors located either inside a substation or along cables. Discussions regarding different PD sensor positioning in a substation can be found in reference [13], where the optimal location depends on the measured PD propagation channels, signal sensitivity, safety and installation practicality.

The approaches of single-sided and two-sided PD monitoring for underground cables suggest different sensor deployment strategies. The single-sided measurement means PD sensor is only installed at one of the cable ends. The sensor will receive the original PD pulse and the reflected pulse from the RMUs. Time-domain reflectometry techniques can be used to determine the location of the PD origin. The sensor deployment strategy for the single-side measurements largely depends on the types of RMUs along the cable, requirement of network coverage and economical considerations. When the types of RMUs can provide a large reflection, a single-side measurement is suitable. Through business case studies, UKPN has found that it is cheaper to use a combination of single-sided measurement and portable PD monitoring systems to locate defects, rather than installing permanent two-sided measurements. Currently, mainly primary substations in UKPN are equipped with PD monitoring systems. Expansion of network coverage can be achieved by installing PD sensors in RMUs. The advantage of two-sided measurement is the capability of locating the PD origin on-line. The sensor deployment strategy depends on the sensor detection sensitivity and PD origin location accuracy. In [14] the authors have studied the influence of RMUs on on-line PD detection and location. It has been shown that the influence of a compact RMU, with two connected cables, can be ignored if the cable length is longer than 1 km. For a 4-km PILC cable, the influence of 9 compact RMUs is negligible and the location accuracy is within 1% of the cable length. However, if the RMUs have more than 2 connected cables, the detection sensitivity decreases significantly. The maximum cable length covered by one-sided measurement is typically half that of the double-sided measurement.

Communications, Interoperability and Standards

There are number of wireless and wired communication media available to enable convenient operations for the distribution networks, as discussed below:

- Cellular Technologies (GPRS/UMTS),
- Satellite communication,
- WiMax/wireless LAN,
- Power line communication (PLC),
- Fibre Optic.

Depending on the requirements from the DNO, one or more of these communication media can be used to enable different levels of communication between LV devices, sensors and control centres by providing differentiated Quality of Service (QoS). There are a number of DMS functionalities (state estimation, data mining and condition monitoring) which require stringent QoS guarantees from the communication medium. Installation and maintenance cost involved with these communication media is a deciding factor and the DNO should be able to evaluate the performance based on cost benefits. Last-mile and backhaul communication media can be decided based on the maximal and minimal performance criteria of the required communication medium based on networks from small to large scale.

Selection criteria for a particular communication medium depend on the following factors and may vary for different DNOs:

- Positioning/location of sensors,
- Frequency of data collection (seconds, minutes or hours),
- Sampling rate of the data from the sensor,
- Time synchronisation between sensors (for accuracy of time stamps),
- Number of parameters (voltages, current, phase angel, etc.) recorded,
- Level of performance (throughput and response time) required by the DNO.

A detailed analysis based on different use-case scenarios has been carried out by Energy Networks Association (ENA), UK (Energy Network Association (ENA, UK) : "High-level Smart Metering Data Traffic Analysis" May, 2010, http://2010.energynetworks.org/smartmeters/) where the required level of performance from communication media can be realised which can also help to identify performance limits. Identifying the maximal and minimal limits of communication medium will help to identify any bottlenecks which might arise due to future deployment of sensors at larger scale. Therefore the DNO should plan effectively to avoid any future problems with communication infrastructure due to small or large scale sensor deployment in the distribution networks which will require a scalable and easily reconfigurable communication solution. DNO partners in the HiPerDNO project have been using number of the listed communication media between their control centres and MV/LV substation or even to the LV level. How these existing communication infrastructures will scale well or accommodate the future surge of data transmission and processing from sensors and other devices is unknown. Detailed specification from DNOs regarding the existing communication media and their performance criteria can be used to deduce their scalability and any potential bottlenecks on the medium which can then help the DNOs to plan appropriately to devise a suitable communication media for their network according to their future requirements.

The term interoperability refers to the ability of technologies, such as Intelligent Electronic Devices (IED), SCADA outstations, intelligent load controllers, embedded generation control, and other information technologies, to communicate and work in concert, either within a company or across company boundaries, even where the technologies are sourced from a range of competing manufacturers. This issue is now widely appreciated as a major objective for the electricity distribution industry and is known to be a prerequisite for the development of smart grids. The use of relevant standards an higher level modelling standards such as the Common Information Model (CIM) [6] have an important role in providing interoperability.

State-of-the-art Power Systems Communication Technologies and Standards

There are number of communication technologies and standards emerging for power systems and some of them are popular and widely used by many DNOs. It is also useful to describe them briefly and highlight key aspects of these different protocols in distribution networks.

Utility Communications Architecture (UCA)

Main advantages or benefits of UCA [9] are highlighted below:

- Interoperability,
- Self-defining devices,
- Time Synchronisation,
- Expandability,
- Independent Functional Structure (media Transmission Applications),
- Protective Function Response Time Capability,
- Peer-to-peer communications,
- Open Data Access,
- Automated Reports,
- Network Management,
- Extensibility,
- Remote Control Substation Event Handling,
- Security/Integrity,

- Easy of Maintainability.

IEC 61850

IEC 61850 is a standard for electrical substation automation. The standard defines abstract data models which must be mapped to a software environment to provide an implementation. Present mappings include: MMS, GOOSE, SMV and web services [8, 9].

IEC 61850 features include (adapted from [8]):

1. *Data Modeling* - Primary process objects, as well as protection and control functionality in the substation, are represented as different standard logical nodes which can be grouped under different logical devices. There are logical nodes for data/functions related to the logical device and physical device.
2. *Reporting Schemes* - There are various schemes for reporting data from server through a server-client relationship which can be triggered based on pre-defined conditions.
3. *Fast Transfer of Events* - Generic Substation Events are defined for fast transfer of event data in a peer-to-peer communication mode.
4. *Setting Groups* - 'Setting Group Control Blocks' are defined to handle the setting of groups so that a user can switch to any active group according to their requirements.
5. *Sampled Data Transfer* - Schemes are also defined to handle transfer of sampled values using Sampled Value Control Blocks.
6. *Commands* - Various command types are also supported by IEC 61850 which include Select-Before-Operate commands with normal and enhanced securities.
7. *Data Storage* - A Substation Configuration Language is defined for complete storage of the configured data of a substation.

Further technical details of IEC 61850 can be found at (http://www.iec.ch).

EG have indicated a strong intention to apply the IEC 61850 throughout the Higher (110kV) and Medium Voltage (10kV to 20kV) levels of their network (see Appendix 2).

IEC 61850 supports the implementation and maintenance of substation automation applications and future (inter-substation) developments. Interoperability between devices from different vendors, support for high speed peer-to-peer messaging, and object-oriented representation of data are included. A comparison between UCA and IEC 61850 is shown in Table 1.

Generic Object Oriented Substation Event (GOOSE)

GOOSE messages are Type 1 or 1A fast messages supported by IEC 61850 and are:

- Multicast,
- Connectionless,
- No guaranteed delivery of messages,
- 4 millisecond data transfer time (near real-time).

IEC 61850	**IEEE TR 1550 (UCA2.0)**
international standard (IEC)	technical report (IEEE; GOMSFE version 0.82)
comprehensive, modular information models – open for easy extensions applying a name space concept	information models (provide for extensions, however name space concept is not included); GOMSFE Bricks are compatible in concept with Logical Nodes in IEC 61850-7-4
configuration language (XML based) for a simplified substation configuration	no configuration language provided
using **prioritized** Ethernet (Ethertype/VLAN) providing high-speed and preferred transmission of GOOSE messages	no priorities supported with UCA2.0-GOOSE
flexible IEC-GOOSE to exchange any information from any data object (digital, analogue, ...)	UCA2.0-GOOSE to exchange fixed number of digital information
sampled value transmission for CTs/VTs	no sampled value transmission supported
Information models and communication services are **independent** from protocols; multiple mappings, e.g., MMS (ISO version 2003) and web services allow for future proven technologies	mapping to MMS (ISO/IEC version 1991); development was refocused on IEC 61850 as a single international standard
control model with **enhanced security**	restricted control model

Table 1: Comparison between IEC 61850 and UCA standards.

Distributed Network Protocol (DNP 3)

DNP 3 is a set of protocols (layer 2 protocol) used between different types of data acquisition control equipments and its primary use is in control centres, remote terminal units (RTUs) and intelligent electronic devices (IEDs). Key features include:

- Robust, efficient, compatible and secure protocol,
- Time synchronization with RTU,
- Event oriented data reporting,

DNP3 is widely adopted within the utilities, particularly electricity distribution and water distribution. The main application of this protocol is to standardise communications between SCADA master stations, SCADA remote terminal units, and other IEDs (Intelligent Electronic Devices). DNP3 is more robust and efficient than previous protocols in this technical field, such as Modbus. DNP3 is essentially a 'layer 2' protocol and provides: multiplexing, error checking, link control and layer 2 addressing. It also supports time synchronisation between units and time-stamping of data, which are very significant aspect for future smart grids.

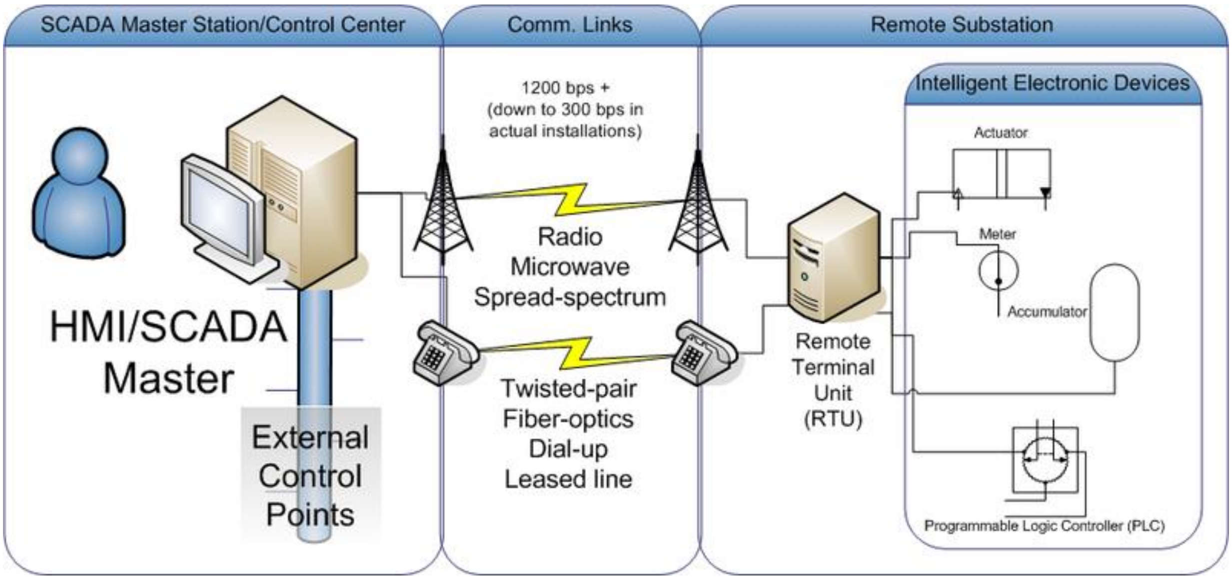

Fig 5. SCADA overview [10]

In the original design of DNP3 security was not considered to be relevant, as the communications network was assumed to be physically inaccessible to malevolent parties. The consideration and introduction of smart grids has encouraged more intrinsic security to be introduced with Secure Authentication, compliant with IEC 62351-5, becoming available. A user group web-site is available which can provide further details of DNP3 (http://www.dnp.org).

Modbus

Modbus is a serial communication protocol for industrial applications which supports many electronic devices (around 240) connection in a network, and is mainly used to connect control centre devices with an RTU. There are a number of variants of Modbus protocols [11] as listed below:

- Modbus RTU,
- Modbus ASCII,
- Modbus TCP/IP,
- Modbus over UDP,
- Modbus plus,
- Modbus PEMEX.

DNP3 is a more advanced protocol than the older Modbus and some key aspects of both protocols are compared in Table 2.

Feature	Modbus	DNP3
Open Domain	✓	✓
Active Users Group	✓	✓
Active Technical Committee	✓	✓
Comprehensive certification procedures	✓	✓
Multiple Data Types (see Table 1)	✓	✓
Standardized data formats		✓
Time-stamped data		✓
Data quality indicators		✓
Report by Exception (RBE)		✓
Unsolicited RBE		✓
2-pass control operations		✓

Table 2: Comparison between Modbus and DNP3 [12]

Strategies for the Future

The off-line field trials within WP4 of HiPerDNO will be based on the latest current sensor and measurement deployments in the DNOs. The results of these field trials are designed to show where significant business benefit and added value can be gained by applying HPC techniques. One outcome will be to help DNOs in formulating their strategy for sensor and measurement deployments in the future. It already seems likely that fast access to smart metering information by DNOs and generally a wider deployment of low cost sensors, linked with low latency and high bandwidth to enhanced SCADA systems, are likely to form the pattern for future developments.

Conclusion

This working paper provides background on sensor and measurement types relevant to the HiPerDNO project. The current status of relevant technologies in the partner DNOs has been presented and discussed. The paper also brings together some of the results and findings of earlier HiPerDNO work packages to help guide the deployment of sensors and measurements. It also makes some suggestions for the sensor and measurement aspects of the future work of the off-line field trials in WP4.

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Appendix 1: Completed Survey from UKPN

	Operational Now Coverage? Accuracy? Cost? Synchronised?	Planned Roll-Out Coverage? . . .	Future Prospects Coverage? . . .
HV (110kV and above)	|V| |I| P and Q Partial Discharge Phasor Measurement Units Any Other Sensors (e.g. Weather Stations) Communications methods Inter-operability standards	In the UK we have 132kV, the highest distribution voltage, usually classified as EHV. We have |V|, |I|, P and Q and transformer temperature measurements. Also measure SF6 circuit breaker gas pressure on sites where these are used. We currently don't have partial discharge monitoring facilities in Grid Substations. In EPN and SPN with some outdoor open substations we have weather monitoring equipment. Use satellite communication in EPN and SPN. For LPN use twisted pilot cables and in some places optic fibre cables.	In the future we will have next generation Remote Terminal Units (RTUs) monitoring phasor measurements and partial discharge activity as 132/11/11kV substations become more common due to load growth.

MV (1kV to 110kV)	|V| |I| P and Q Partial Discharge Phasor Measurement Units Any Other Sensors (e.g. Weather Stations) Communication methods Inter-operability standards	We have 66kV, 33kV, 22kV, 20kV, 11kV, 6.6kV and 2.2kV. 66kV and 33kV are classified as Primary voltages. 66kV is found in LPN and is being phased out. 33kV is used in all 3 of UKPN regions. 11kV is the common distribution voltage found across all three areas. While 22kV and 20kV are used in LPN as distribution voltages. 6.6kV and 2.2kV are being phased out. We have |V|, |I|, P and Q and transformer temperature measurements for 66kV and 33kV. Partial Discharge is currently being tested for 11kV feeders in some Primary substations. For Primary substations satellite communication used in EPN and SPN. For LPN pilot cables and optic fibre cables. In distribution substations of 22kV, 20kV, 11kV the RTU monitors |V| and |I|. Distribution substations use GPRS to communicate, using the Paknet protocol.	In the future we will have next generation Remote Terminal Units (RTUs) monitoring to include phasor measurements and partial discharge activity. The RTUs installed on the 11kV distribution network have the ability to measure P and Q with direction of flow, Power Factor and Total Harmonic Distortion. There are plans to use these functions in the future in order to provide greater visibility of the network.

LV (below 1kV)	|V| |I| P and Q Partial Discharge Phasor Measurement Units Any Other Sensors (e.g. Weather Stations) Communication methods Inter-operability standards	Currently only have Maximum Demand Indicators (MDI) on each phase in an LV Board. These only record the maximum current seen on each phase. They are read manually and data input into Asset Management System via handheld device.	Smart meters found on each LV way/board in distribution substations and measurement devices in smart link-boxes with switching capability. Will use Power Line Communication protocol.

Appendix 2: Completed Survey from UF

	Operational Now Coverage? Accuracy? Cost? Synchronised?	Planned Roll-Out Coverage? . . .	Future Prospects Coverage? . . .
HV (100kV and above)	|V| |I| P and Q Partial Discharge Phasor Measurement Units Any Other Sensors (e.g. Weather Stations)	In UF, in general, we get 400 & 220 KV information (|V|, P and Q) from TSO (REE). Network in 132 has measurement transformers, converters and RTUs in all power stations for P,Q,I,V. 100% coverage.	

MV (10kV to 100kV)	|V| |I| P and Q Partial Discharge Phasor Measurement Units Any Other Sensors (e.g. Weather Stations)	We are installing in 15 and 20 KV new substations |V|, |I|, P and Q. In older rural substations (HV/MV) we just have I and U measurands.	Installation of remote control for switches in MV network for selected ones.
LV (10kV and below)	|V| |I| P and Q Partial Discharge Phasor Measurement Units Any Other Sensors (e.g. Weather Stations)		In future we plan to install measurement equipment together simultaneous with smart meters installation stations with P,Q,I and V sensors.

Appendix 3: Completed Survey from EG

	Operational Now Coverage? Accuracy? Cost? Synchronised?	Planned Roll-Out Coverage? . . .	Future Prospects Coverage? . . .
HV (110kV and above)	|V| |I| P and Q Partial Discharge Phasor Measurement Units Any Other Sensors (e.g. Weather Stations) Communications methods Inter-operability standards	|V|, |I|, P and Q In Slovenia the 110kV (belongs to TSO) network we have installed these sensors in all power stations. 100% coverage We have optical communication units (SDH, Ethernet.)	In future is IEC61850 planned for all devices, relays, bay units, sensors,…

MV (40kV to 110kV)	|V| |I| P and Q Partial Discharge Phasor Measurement Units Any Other Sensors (e.g. Weather Stations) Communication methods Inter-operability standards	We do not have this voltage levels in Slovenia.	

MV (10kV to 40kV)	|V| |I| P and Q Partial Discharge Phasor Measurement Units Any Other Sensors (e.g. Weather Stations) Communication methods Inter-operability standards	|V|, |I|, P and Q In Slovenia the 10kV to 20kV somewhere 35 kV (belongs to DSO) network we have installed these sensors in all distribution power stations. 100% coverage. We have also some sensors installed in remote switches across the medium network. Optical network in substations. Moscad radio in remote switches.	Installation of sensors in medium network, depending on the operational needs (together with switches). Use of IEC 61850 standard.

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LV (10kV and below)	|V| |I| P and Q Partial Discharge Phasor Measurement Units Any Other Sensors (e.g. Weather Stations) Communication methods Inter-operability standards	|V|, |I|, P and Q. we have installed some sensors in 20/0.4kV transformer stations, about 20%, MI7150, network analyser. But only some of them are remotely read. GPRS, communications in future Wimax.	In future we plan to equip together with smart meters all transformer stations with these kinds of sensors.