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Supporting Energy Efficiency in Smart Generation Grids Through ICT

Thematic Network

ICT PSP Programme

REPORT ON ICT REQUIREMENTS, OFFERS AND NEEDS FOR MANAGING SMART GRIDS WITH DER

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Executive summary

This deliverable presents a **survey** of intra-grid applications in smart distribution networks that require an advanced ICT-infrastructure. This report deals with those approaches for the **technical management of smart distribution grids** that require information and communication technology and which allow the society to have a better, more efficient usage of electrical energy. Exemplary topics of **voltage control, adaptive protection** and **reconfiguration** have been dealt with. Demand response and grid monitoring are outside the scope of this deliverable as they are treated elsewhere in the project.

It has been identified that the control and coordination of distributed energy resources, which are spread throughout the distribution network, require a suitable communication between the different generation units and the distribution network operator. This communication must be bidirectional (including control signals, state signals, measurements and alarm signals) and sufficiently fast, since the introduction of excessive time delays into the control system can destabilize the entire electric grid, jeopardizing the quality and safety of power supply. Main **functionalities provided by DG units and the main features of communication channels** namely data transfer rate and data volume, response time (latency of packets), application priority, reliability of the communication channel, availability of communication channel and security and privacy have been identified. Suitability of the various **telecommunication technologies** based on the function assigned to DG units are enlisted in the report.

The results of the EU projects like DemoNet, INTEGRAL and CRISP have been studied and the **different network entities** involved in the communication process have been identified. The idea is to communicate between the different entities the data / measurement / control signals to achieve the objectives like voltage control for better power quality or to quickly locate faults for enabling reduction in outage times or to reconfigure the grid for minimization of loss etc. This contributes to enhance the service to the customers thereby improving the quality of electricity supply. The experience of R&D work like AuRA-NMS and the deployed pilot projects of the industrial partners like PPC & ENEL have been included in the report. The various pilot projects deploy advanced communication features for achieving grid management. Additionally, several research papers on voltage control, adaptive protection and grid reconfiguration have also been included in the report.

Though there are **many research and pilot projects** in the field of ICT for voltage control for intra-grid management with DG included, the R&D is substantially lower for ICT in more advanced smart grid applications such as **grid reconfiguration**. Also, the **large scale deployment** of ICT in any of the exemplary aspects of intra grid management namely, voltage control, adaptive protection and grid reconfiguration is almost **non-existing** as of now. Hence, there need to be more R&D work with regard to ICT in intra-grid management that has to be carried out along with the implementation of various ideas developed from the R&D work in pilot projects.

ICT requirements for intra-grid management applications such as voltage control, adaptive protection and grid reconfiguration include data transfer rate and volume, response time, priority, reliability and availability of communication channel, security, privacy, interoperability, scalability and robustness parameters. This deliverable qualifies and quantifies these elements.

1 Introduction

SEESGEN-ICT work package (WP) 2 considers how Information and Communication Technology (ICT) can be used for a better management of smart grids in which many Distributed Energy Resources (DER) are integrated.

The objective of the deliverable is to make a survey on the different ICT-approaches that can be applied for the better management of smart grids. As identified in the strategic agenda [1], the priority of the work will be given to the approaches for the technical management of smart distribution grids that require information and communication technology and which allow the society to have a better, more efficient usage of electrical energy.

Exemplary topics that fall within the scope of this work package are described shortly.

- Voltage Control: Voltage control in the smart distribution grid will not only be based on the local measurement of electrical quantities, but also on the exchange of values concerning these quantities among the different control points in the distribution grid. Using such information, the controller at the distribution system operator or elsewhere can use DER to contribute to the reactive power management in the grid and, as such, improve the energy efficiency.
- Adaptive Protection: In distribution grids with bidirectional power flows adaptive protection is required in order to deal with the direction of short circuit currents and to ensure selectivity. Communication among protection devices can ensure reaching these goals but puts stringent requirements to the involved ICT.
- Reconfiguration: Smart grid management may imply the reconfiguration of the topology of the distribution grid – if sufficient hardware (switches, breakers,…) is available – in order to better handle the load and generation in the grid due to a large amount of unpredictable DER and faults. Such reconfiguration can be applied pro-actively before emergency conditions occur, or reactively after an alarm triggers. This latter reactive approach also relates to 'self-healing' distribution grids. Proactive and reactive actions are commanded by controllers, based on information provided via different sensors in the grid and communicated to the former.

Such topics are chosen because they maximally illustrate the potential of smart grids and clearly show the challenges to reach such goals. The ICT approaches for the management of smart grids with DER integration will be considered from different perspectives: a multidimensional view allows having an orthogonal view onto the discussed items.

The first dimension to be considered deals with the domain and specific application in which the ICT approach will be applied. Specific domains include for instance:

- planning
- operation and control
- asset management
- portfolio management

Given the above-defined scope, the major focus for the management of smart grids lies within the domain of 'operation and control'. In this domain, representative specific applications include:

- voltage control, not purely electrical, but where ICT provides specific opportunities
- adaptive protection (if it is distributed and based on ICT solutions)

- distribution grid reconfiguration (proactively and reactively)

The second dimension to be considered concerns the typical problems that occur for such ICT approaches.

The third dimension is the maturity of the approach. The major steps include:

- research in university or industrial laboratories
- developments and realizations in companies
- pilots on smaller scales
- deployment on larger scales

This three-dimensional matrix will be sparsely filled with entries that elaborate ICT approaches to the management of smart grids with DER integration.

The structure of the document is as follows. In section 2, generic functionalities of DG units are matched against ICT features. The sections 3 to 5 describe the representative applications introduced above, mainly based on research projects. Section 6 describes the industrial state of practice and section 7 summarizes the major conclusions of this first phase of work package 2.

2 Matching the functionalities of DG units and the features of ICT

2.1 The need for ICT in managing smart grids with DER

In recent decades, the electric power industry has been undergoing a dramatic transformation, from generation, transmission to distribution. Electric power distribution networks are transformed to smart systems which interconnect bulk supply points, small-scale distributed generators (DGs) and loads across a wide geographical area. This includes the increasing interest of utilising renewable energy sources, e.g. wind and solar energy, to power distribution networks, which is mainly driven by advances in renewable energy technology and the ambition of meeting the target of CO_2 emissions reduction and the demand of enhancing energy security and quality of supply. However, the integration of a large number of DGs brings many operational challenges in power distribution networks, e.g. the voltage rise effect, power quality, protection and stability [2].

Currently most distribution network operators (DNOs) rely on Supervisory Control and Data Acquisition (SCADA) with a centralised structure for monitoring and control of their distribution networks to ensure their secure, economic and reliable operation. Due to the growth of DGs and the scale of the networks, this conventional centralised control approach is no longer sufficient and practical for managing these smart distribution networks which call for more advanced smart grid management solutions. Such smart grid schemes require an efficient and reliable communication infrastructure to enable system monitoring and control in predefined control regions, as well as cooperative behaviour with other regional controllers in finding an optimal set of control actions.

However, the DNO's current communication provision in SCADA systems were, by and large, built a few decades ago with limited communication capability and a centralised structure. This greatly constrains the usage of existing SCADA systems for supporting the smart grid management.

The control and coordination of distributed energy resources (DER), which are spread throughout the distribution network (including several kilometres), require a suitable communication between the different generation units and the distribution system operator (DSO). This communication must be bidirectional (including control signals, state signals, measurements and alarm signals) and sufficiently fast, since the introduction of excessive time delays into the control system can destabilize the entire electric grid, jeopardizing the quality and safety of power supply.

2.2 Main functionalities provided by DG units

The information flow required to control distributed resources in the MV electricity networks depends on DER nature (traditional or renewable sources) and the regulation/control scenarios considered in DG management (ability to control active power production, reactive power exchange etc.). The different functions provided by DG units can be summarized in the following points:

- Inject into the distribution grid the energy surplus, derived from both cogeneration processes and self-producers (energy production greater than consumption).

- Produce the maximum power at all times, especially in case of renewable energy sources such as wind and hydro power plants, which are subjected to incentive mechanisms to maximize the energy production ("green certificates" in Italy, Belgium and others, "ROC" in the United Kingdom).
- Reduce the power production (peak-shaving) in order to limit the oscillations of possible operating conditions.
- Avoid unintentional islanding (anti-islanding protection) by sending a tripping command/message from the HV/MV substation that forces interface relays to open.
- Support voltage control by modifying the amount of reactive power generation (for example using a coordinated control logic [3]).
- Support the network transition to intentional island operation in case of unreliable primary supply. Although this possibility ensures some benefits regarding the availability of power supply, it is probably the most difficult condition from the control perspective (active and reactive power balance in the network, problems related to the intervention of the protections and the resynchronization of the HV network, etc.)

Besides the above features, there is an additional set of functions that DG facilities must provide while connected to the main network:

- Allow the correct diagnosis of the network, avoiding misleading situations that hide possible grid problems
- Ensure the correct fault clearance without affecting the proper functioning of network protections
- Maintain the security of network operators
- Ensure the correct measurement of energy transactions (in order to monitor the power system operating conditions and apply the correct energy tariffs)

The operation of DG units connected to the distribution system requires substantial data exchange, usually bidirectional. For a coordinated voltage control of MV distribution networks with high DG penetration, as illustrated in Figure 2.1, the generation units must be able to receive command signals from the central controller located at the primary HV/MV substation. Such signals are power factor set points for DG units, which are evaluated by the controller to optimize the voltage profiles in the distribution grid (reactive power exchange with the MV network) while controlling the reactive power flows in the feeder (reactive power control to provide an ancillary service to the HV network). On the other side, local voltage measurements at the DG buses must be sent to the central controller, as well as reactive power flows and voltage at MV bus.

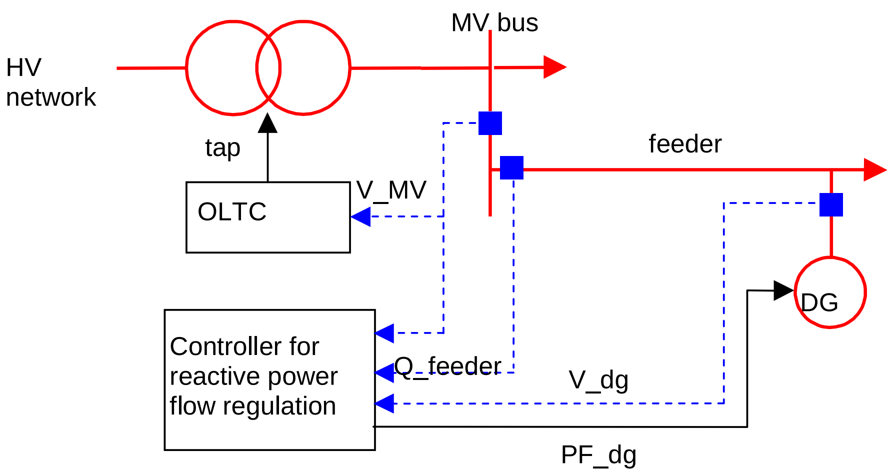

Figure 2.1: Communication architecture for a coordinated control of active distribution network

Clearly, a complete remote control of DG units involves additional information [4], which depends on the type of generation plant (primary energy source, implemented technology, electrical interface with the distribution network, etc.). The central controller, which coordinates the operation of the MV network (and therefore DG units), uses such information to identify in real-time the operating conditions of power components, their availability to receive and execute the control signals, the presence of local alarms, etc. These data demand high reliability, since they are very important to estimate the state of distributed generators and to prevent abnormal situations for both distribution system and DG itself.

The generator data usually refer to quantities of different nature (electrical, mechanical, thermal and atmospheric). Such information can be processed locally or centrally in order to define an optimal dispatch of the generation units (power production cost of each DG, start-up and shutdown costs, etc.).

2.3 Main features of communication channels

Each DG unit requires a communication channel with suitable characteristics to actively participate to a particular control strategy. Therefore, it is important to identify the key features of data flows between DSO and DER for defining the appropriate communication system. Briefly, a communication channel can be classified according to the following requirements.

- Data transfer rate and data volume

The *data transfer rate* is the amount of data that can be sent or received within a time interval and it is usually measured in bits/second or bytes/second. For each DG unit, it is necessary to define the ICT requirements in terms of data transfer rate (*throughput*) and volume of data to be exchanged. This second aspect can be evaluated as the time interval for which the communication channel must be available both in download (to DG units) and in upload (from DG units) direction.

- Response time (latency of packets)

The response time is the elapsed time between the signal emission by the transmitter and the signal acquisition by the receiver. This requirement, usually known as *latency*, is one of the most critical parameters of a telecommunication network.

Control applications of distribution networks may have different needs in terms of response time of the communication channel. In fact, latency is a very restrictive parameter for the definition of the communication channel, especially for applications that do not accept high and uncertain time delays in the control process (for example, MV network transition to island operation in case of a blackout in the HV transmission network).

- Application priority

In case of simultaneous applications running on the same communication channel (simultaneous information exchange between different actors in the network), it is necessary to define a *priority* to the use of the channel by each application. If the communication channel is managed by a master, it will allocate resources according to the application priorities, i.e., applications with restricted constraints on latency are authorized to take advantage of the channel before others.

- Reliability of the communication channel

Reliability is the ability of a system or component to perform its required functions under stated conditions for a specified period of time. The reliability of communication systems is affected by disturbances on the signal transmission and/or frequent interruptions of the channel. Disturbances do not necessarily affect the communication, since modern protocols have specific algorithms that are capable of recovering the package information or requesting data retransmission (with a proper trade off between error control and throughput).

When DG units are remotely operated, the reliability of the signal transmitted to the central controller is very important, since it is not possible to verify “on-site” the quality of exchanged signals.

- Availability of communication channel

Availability is the ability of a system of component to be in the state to provide its required functions under given conditions at a given time instant. In other words, availability is the proportion of time that a system is in a functioning condition and it is usually quantified as follows: $A(t)=E(\text{Uptime})/(E(\text{Uptime})+E(\text{Downtime}))$ at time t

Availability is an important parameter when defining ICT requirements, especially for the grid management in emergency conditions (black-out, failure and protection intervention).

- Security and Privacy

Dangers: Open system architectures which use existing internet or telecom infrastructure to reduce cost and increase efficiency, are also prone to malicious attacks. All activities and interactions on the power system must be protected from attacks which could do harm to the business operations or the system reliability. At any point of local operation, the health of the larger system must be preserved.

Confidentiality: The exchanged information is held privately and is used only for the purpose of the business transacted. It is protected from unauthorized parties.

Integrity and Transaction: The received information may not be altered. Transmission must be encrypted and protected from "man-in-the-middle" attacks. Transactions have a start and a clearly defined end. Any failure or interruption of the transaction process leads to a "roll back" of the actions done so far, thus to return to the last valid state before the transaction started.

Authorization: Different policies for level of access must exist for the different roles of the users. This separates the simple user role from the system operator and more privileged roles.

Vulnerability: A large, global scale of same architectures can be threatened by attacks to single weakness of the system. Therefore changes to the standards must be validated before deployment to avoid this. On a local scale another threat could be a kind of "denials of service" attacks: link layer denial and association denial – requests from many clients could harm the operation of a server node. The system must be protected from direct access and illegitimate use in an unauthorized way.

2.4 ICT requirements

Once identified the most important features of communication channels, it is possible to define the ICT requirements according to the specific function that DG units are intended to provide, i.e., voltage control, generation curtailment, etc. For such a scope, it is useful to quantitatively define the different ICT requirements in this smart grids context according to suitable reference ranges.

The data *transfer rate* can be classified as:

- High = greater than 100 kbit/s;
- Average = between 5 and 100 kbit/s;
- Low = between 1 and 5 kbit/s.

The reference sets for what concerns the *latency* are:

- Low = between 5 and 60 s (in some applications it could be even higher).
- Average = between 0.5 and 5 s;
- High = less than 500 ms (anti-islanding signal should be transmitted within 200-300 ms).

The *application priority* is usually quantified as a reciprocal ratio among the different users of the communication channel and so the priority cannot be defined as an absolute value.

The *availability* of the communication channel, which is clearly related to the relevance of each application, can be defined as follows:

- High = greater than 99.9%;
- Average = between 90% and 99.9%;
- Low = between 80% and 90%.

Finally, the *reliability* of the communication channel can be quantified in terms of Bit Error Rate (BER), as indicated below:

- High = information loss smaller than 0.01%;
- Average = between 0.01% and 0.1%;
- Low = between 0 .1% and 5%.

Table 2.1 summarizes the ICT requirements as a function of the different services requested to the DG units. Table 2.2 classifies the feasibility of available communication technologies to support the DG services described above. After identifying the ICT requirements for the grid management, it finally illustrates the possible applications (in terms of services provided by DG units) of the most common communication technologies.

	Transfer rate	Latency	Priority	Reliability	Availability
Inject energy surplus into the grid	×	×	×	×	×
Produce maximum power	×	×	×	×	×
Peak shaving (generation curtailment)	✓	✓✓	✓	✓	✓
Anti-islanding	×	✓✓	✓✓	✓✓	✓✓
Voltage and reactive power regulation	✓	✓	✓✓	✓	✓
Support island operation	✓	✓✓	✓✓	✓✓	✓✓
Ensure correct operation of power system	✓	✓✓	✓✓	✓✓	✓✓

Table 2.1: ICT Requirements based on the function assigned to units DG
(✓✓ High, ✓ Medium, × Low)

	Mobile networks	Satellite networks	WLAN	PLC	PLT	Wired networks	Fieldbus
Inject energy surplus into the grid	✓✓	✓✓	✓✓	✓✓	✓✓	✓✓	✓✓
Produce maximum power	✓✓	✓✓	✓✓	✓✓	✓✓	✓✓	✓✓
Peak shaving (generation curtailment)	✓	✓	✓✓	✓	✓✓	✓✓	✓✓
Anti-islanding	✓	✓	✓✓	×	×	✓✓	✓✓
Voltage and reactive power regulation	✓✓	✓✓	✓✓	✓✓	✓✓	✓✓	✓✓
Support island operation	×	×	✓✓	✓	✓✓	✓✓	✓✓
Ensure correct operation of power system	×	×	✓	×	✓	✓✓	✓✓

Table 2.2: Suitability of telecommunications technologies based on the function assigned to DG units (✓✓ suitable, ✓ partially suitable, × improper)

It is mentioned in [5] that in Aura-NMS, the control algorithms need to act in their designed time scales to fulfil their functions. Some control functions have stringent latency requirements, e.g. restoration actions after faults need to be taken as soon as possible, ideally within a few seconds and under-voltage load shedding control action needs to be operated within about 10 seconds. On the other hand, some control functionalities may require slow actions, e.g. on-load tap changers act in the time-scale of tens of seconds and thermal phenomena (e.g. transformer overheating) may tolerate a delay of several minutes before a control action is taken. Therefore, the underlying communication system needs to be enhanced and properly managed to guarantee timely data delivery and service differentiation to meet diverse latency requirements. The maximum message delivery time required for selected types of information to be exchanged between applications with the substation and with applications external to the substation is shown in Table 2.3 and substation communication performance requirements are shown in Table 2.4 [6]. Such information needs to be considered during the determination of ICT requirements, offers and needs for managing smart grids.

Information types	Internal to substation	External to substation
Protection information, high speed	¼ cycle	8-12 ms
Monitoring and control information, medium speed	16 ms	1 s
Operations and maintenance, low speed	1 s	10 s
Text strings	2 s	10 s
Processed data files	10 s	30 s
Program files	60 s	10 min
Image files	10 s	60 s
Audio and video data streams	1 s	1 s

Table 2.3: Data delivery time required

Data/Application	Critical Class	Priority Class	Rate	Maximum Delivery Time	Notes
Line Protection and Control			On demand for all messages		
Breaker tripping and breaker failure initiate(BFI)	High	High		¼ cycle	Actual breaker operation may take 1 – ½ to 8 cycles
Back up breaker tripping (after breaker failure time out)	High	High		8 to 12 ms	
Breaker reclosure including voltage supervised, multiple	Med	Normal		8 ms	
Control of transfer trip for SEND / RECEIVE	High	High		¼ cycle	
Keying of permissive schemes	High	High		8 ms	
SEND/RECEIVE trip command	High	High		2 to 8 ms	
Initiate lock out function (not in mechanical lock out)	High	High		16 ms	
Motor-operated disconnect	Med	Normal		16 ms	
Indicator control	Med	Normal		2 s	
Testing of trip and block channels	Med	Low		2 s	

Data/Application	Critical Class	Priority Class	Rate	Maximum Delivery Time	Notes
Bus zone protection and test including			On demand for all messages		
Send trip signals to adjacent zones	High	High		8 to 12 ms	
Block auto reclose for all bus-connected breakers	High	High		8 to 12 ms	
Initiate lock out function for bus differential	High	High		16 ms	
Select bus testing source	Med	Normal		16 ms	
Enable closing of selected testing source	Med	Normal		16 ms	
Lockout reclosure of breaker following unsuccessful test	Med	Normal		16 ms	
After successful test enable reclosure of remaining breaker	Med	Normal		1 s	
Loss of potential	High	High		¼ cycle	
Distribution Applications					
Line sectionalizing	Med	Normal		5 s	Non-under frequency condition.

Data/Application	Critical Class	Priority Class	Rate	Maximum Delivery Time	Notes
Load control and load shedding	Med	Low		10 s	Triggered by under frequency relay.
Load shedding for under frequency	High	High		10 ms	
Fault identification, isolation and service restoration	Med	Normal		10 s	Reporting function.
Fault isolation and service restoration	Med	Normal		Several minutes	
Transfer switching	Med	Normal		1 s	
VAR dispatch	Med	Normal		1 s	
Voltage dispatch	Med	Normal		1 s	
SCADA- stand alone or distributed	Med	Normal		1 s	

Table 2.4: Substation communication performance requirements

Table 2.5 shows the minimum latency requirements that have been defined by the "network of Energy and Communication" [7].

Type of task	Min. latency	Frequency
Command and reply	2 sec	1-30 per day
Status information - failure - status of operation	 1 sec 5 sec	 <1 per day 1-30 per day
Transmit set points (P,Q)	2 sec	1-30 per day
Readings of measurements	2 sec	Every 5-10 sec
Readings of counter	2 sec	1-30 per day
Daily profile (P,Q – 96 quarter hourly)	20 sec	1-2 per day
Transmit parameter	10 sec	1-30 per day
Protection error event protocol	1 min	<1 per day

Table 2.5: Minimum latency requirements of communication in distribution networks

- "Status information" will show up failure and operation information of the assets
- "Readings of measurements" are necessary for several voltage control algorithms
- Readings of the 15min profile leads to better forecast and prognosis and better scheduling of the distributed generation and the load management, which is required for energy-management of Virtual Power Plants
- To ensure consistent standard in communication, interoperability and independency in terms of the communication medium, the following requirement according to IEC 61850 reference model for the layers of the ISO/OSI communication structure must be strictly adhered:
    - consistency of the data content
    - services with their receiving confirmation must be consistent on every layer

At the present time, it seems that no technology fully matches all communication needs when equipment costs are taken into account (installation costs and communication charges). Economic aspects are particularly important in distribution grids because, unlike large generation plants connected to HV transmission system, the costs to ensure an adequate communication could have a relevant weight in the overall investment required for the DG installation. High performance communication technologies (more expensive) should be only applied to delicate applications that provide substantial benefits to the network (e.g. the protection coordination during a failure or grid management in island operation), thus compensating the large installation costs. Low-cost communication technologies should be used wherever real-time monitoring is not required (i.e., event logging) and also in control applications that allow moderate transmission delays (i.e., when the processes of interest are characterized by slow dynamics). An important example of such control applications concerns the use of DG units to control the voltage profile in the distribution system or to provide ancillary services to the transmission grid.

The assessment of ICT requirements for an effective control of distribution networks with DER should be based on a careful survey of the data (both monitoring and control signals) to be exchanged between generators and DSO.

3 ICT requirements for voltage control applications

3.1 Introduction

Voltage control, in its simplest description, is keeping the voltage between the defined limits. Voltage control requires that there are no large circulating currents between the sources. The key limiting factor for the development potential of DG in 30kV networks and below is the over voltage problem. Without massive grid reinforcement, additional generators would frequently be switched off by over voltage protection. Keeping the voltage between the defined limits is becoming a primary concern of DNOs. Increasing level of DG penetration causes the voltage to rise above limits, presenting risks for customer equipment. As the present DNO's voltage control equipment is only able to handle limited amount of DG, the modification, replacement and new installation of different equipment is necessary to increase the DG penetration on the distribution networks. Loads, line impedances, power exported by the DG and the distance of the DG from the primary substation are the most important factors causing the changes in the voltage profile.

Option	Advantage	Disadvantages
Modem dial-up / dedicated line	o easy to install o medium costs	o not always available (or expensive) o long time for dial-up o external provider
GSM/UMTS	o highly available (continuous connection) o easy to install o low costs	o not 100% reliable o external provider o security problem due to internet tunnelling
Distribution line carrier (DLC)	o belongs to DSO o medium costs	o problem of attenuation due to high number of stations in the communication channel o problem of radiation (if high bandwidth)
Radio link	o easy to install o belongs to the DSO o medium costs	o limited range o dependence of topographical conditions o wave band has to be licensed
Glass fibre	o very high availability o high bandwidth o low latency o belongs to DSO	o high installation efforts o high costs

Table 3.1: General communication options for voltage regulation in the medium voltage net

3.2 DEMONET experience

DEMONET project report [8], details the method of voltage control as follows. To avoid unnecessary reactive power flow and power curtailment, a hierarchical concept is introduced. The central control station is placed at the primary substation where the OLTC transformer (on-line tap changer) is located. The central control unit collects measurement data from critical points in the network. Communication lines are required to transmit measured voltages from remote points. Depending on the chosen communication technology, a varying delay on these lines has to be expected. The control station determines the maximum and minimum voltage point in the network based on the incoming measurement data. According to maximum and minimum voltage, the OLTC transformer is set. In case of voltage conflict, e.g. when the tap change would cause voltage to exceed the limits, the OLTC is not able to solve the voltage problem. In this case local voltage control with DG is activated. Only DG units that allow for controlling the voltage are included in the coordinated control. A ranking order of DG units is introduced for optimal operation (hierarchical system). DG units are ranked according to their voltage impact to each monitored point. First, reactive power management is used to control the voltage. In case reactive power management reaches its limits, voltage control with available active power is introduced.

When adopting coordinated voltage control as suggested in DEMONET project report, the entities involved are:

a) Central controller located at the substation
b) OLTC
c) Selected DG units that are there at the field
d) Chosen critical points in the network

The Figure 3.1 developed during the course of the project DG DemoNet-Concept shows a catalogue of measures in the form of a circuit diagram. The illustration in the figure follows the principle from the general idea (above) down to details (below)

(1) Control with on load tap change transformers due to the voltage of the transformer station
(2) Control with on load tap change transformers due to the metered value of critical nodes in the network area
(3) Local voltage control at critical nodes with reactive power control at generation units
(4) Local voltage regulation at critical hubs with active power at generator plants
(5) Readjustment with adjustable transformers (MV/MV)
(6) Local voltage control at critical nodes with load management

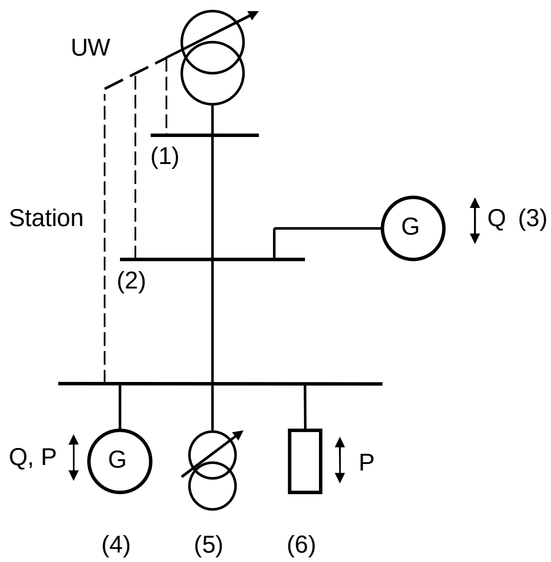

Figure 3.1: Various measures for voltage control

3.3 CRISP experience

According to the CRISP project report [9], voltage transformers are typically available on the HV side of the power transformer. It is possible to monitor the HV side voltage magnitude and consequently influence the operation of the AVR (automatic voltage regulator) or other equipment in the substation. For the best security scheme it is desirable to measure all three phase-to-earth voltages from the HV side, in order to take necessary actions only when all three voltages are above or below the pre-set level. Therefore, operation of the AVR will be influenced by the measured voltage level on the HV side of the power transformer.

The following typical actions can be taken:

a) Temporary AVR block (say, for 20 seconds)
b) Temporary AVR voltage set point change (typically reduction)
c) Complete AVR block until manually released by the system operator
d) HV shunt capacitor (reactor) switching
e) Under-voltage load shedding

3.4 INTEGRAL experience

The INTEGRAL project report [10], describes about *coordinated* voltage control; with the addition of DG onto the grid, the voltage profile of the grid may be affected but this can be controlled by the help of modulating reactive power injection from the DG units. The voltage control can be achieved by taking advantage of distributed generation reactive power injection to maintain voltage to its set point value at the substation and some other specific nodes called pilot buses. While controlling the voltage profile, there is a constraint that the injection of the reactive power must not result in huge power loss; thus we need to optimize the voltage profile and at the same time minimize power losses.

When adopting coordinated voltage control as suggested in INTEGRAL project report ; the entities involved are:

a) DG units
b) Pilot buses
c) Substation

3.5 Aura-NMS experience

Every distribution utility has an obligation to supply its customers at a voltage within specified limits. This requirement often determines the design and expense of the distribution circuits and so, over the years, techniques have been developed to make the maximum use of distribution circuits to supply customers within the required voltages. The precise voltage levels used differ from country to country but the principle of operation of radial feeders remains the same [11].

Most voltage control contains two main sub-functions:

- Identify Voltage Excursion (IVE)
- Voltage Excursion Relief (VER)

The IVE sub-function has the role of locating and identifying the severity of the voltage excursion on the power network. Its performance relies heavily on the available measurements and the availability of a state estimator. The network data are in two categories:

Static network data: These are the data gathered only once and updated when the network status changes.

Dynamic network data: These are the data gathered periodically, e.g. every 5 minutes.

Table Tables 3.2 and 3.3 summarize the data input of IVE for both categories [5].

Input	Description
Get voltage limits for normal/abnormal conditions	V limits (Statutory/DNO specific limit relating to normal/abnormal conditions)
Get details of connections between components	NOP,CB
Get cable/line details	R,X
Get transformer details	tap position, step, min/max tap
Get generator component data	Get P, Q generating chart
	Get definition of governor control system
	Get definition of excitation system
	Get grid code requirement
	Get PPA terms and conditions
	DG scheme connection data
	DG type

Table 3.2: Static input data for voltage control

Input	Description

Input	Description
CB status	open/closed
loads/estimated loads	P,Q and confidence indicator
Get status of on load tap changer	tap position
Voltage	V(magnitude and phase)
Get status of DG	P,Q PF and its control ability
Get estimated Voltage (from state estimator)	Estimated V (magnitude and phase) with confidence indicator
Get estimated future status of DG (from state estimator)	Estimated P,Q,PF and control ability with confidence indicator
Get estimated of the period of time of potential increase/decrease in the short term or medium term (from state estimator)	P and Q with confidence indicator
Get ESS status	ESS charge/discharge status, parameters

Table 3.3: Dynamic input data for voltage control

Once an excursion has been identified, the IVE sub-function feeds the VER sub-function with the obtained data. The VER then generates a set of solutions which will be evaluated and the most suitable solution will be selected and the control action will be generated. The output of the voltage control function will be a control message sent to an entity of the power network such as: Energy Storage System (ESS) regulation, Distributed Generator (DG) real power curtailment control discharge, etc.

3.6 Power quality project

The concept described in the paper [12] uses reactive power which is generated in the solar power inverters to increase power capability of the grid. By means of additional reactive power consumption, the grid voltage can be decreased to acceptable values and stabilized. Grid extension in many cases can be avoided or, at least it can be delayed. For control of a distributed system of a number of solar inverters installed in a grid segment, distributed data collection and central control is required. Data and control parameters are being transmitted over the power lines with inbuilt real time DLC (distribution line carrier) communication. With the technology shown in the paper higher reliability, increased and controllable power quality and less problems in low voltage grids can be achieved. Thus, capability to accept and integrate more decentralised generated power can be improved.

The approach described in this paper is to implement additional functionality into power electronic equipment which is permanently connected to the grid to improve power quality. Modern power electronic devices provide fast switching and low losses during operation. New communication technologies use power lines for real time data transmission. Main advantages of this technology are in the availability of data communication at any location on the power grid and a high level of reliability because no additional equipment or service provider is required. The combination of both technologies, power electronics and information and communication technology, enables the control of a distributed system as described in this paper.

The operational status of the grid has to be measured continuously at connection points of large loads and decentralized generation. Solar inverters are equipped with data acquisition capabilities because they need to synchronize their voltage and frequency to the grid voltage. For load connection points measuring technology is to be installed. As shown in Figure 3.2 a main computer is networked to a number of data acquisition devices and solar inverters. Data acquisition devices and solar inverters monitor voltage, current and power flow at their locations on the grid. Data acquisition devices are located at large loads (e.g. industrial plants) and grid nodes. The main computer receives the grid status data and then calculates the values for the required reactive power for the individual solar inverters which will be sent over the data net-work to the inverters.

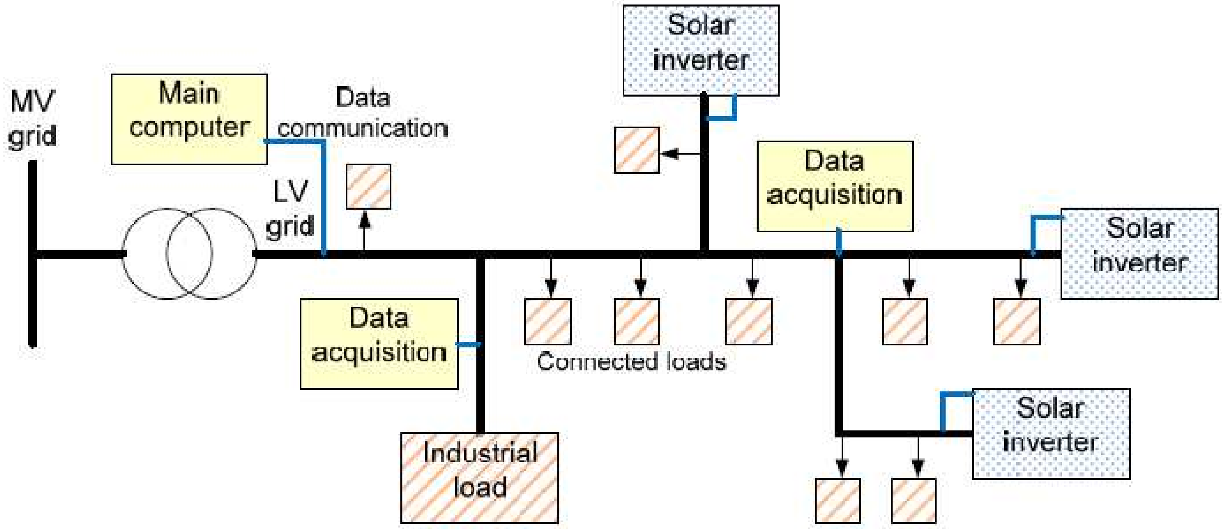

Figure 3.2: Data acquisition and control structure

Reliable operation of safety critical applications requires high level communication technology and data transmission regarding short response times, time synchronisation and robustness against electromagnetic distortion. Thus, efficient pre-processing and data compression with use of encryption algorithm is required. Besides, for this application a high number of distributed components have to be monitored, coordinated and controlled, whereas a lot of plants in the energy sector are not connected to a communication network. Therefore, the use of an economic communication technology is required and the use of the power line for communication is the natural and most appropriate solution.

The power line is a dynamic network which requires the possibility for fast reconfiguration of communication links. The DLC-2000 system from iAd, which is chosen as the backbone of the proposed system, is the only existing PLC system which is able to meet the requirements with respect to guaranteed real-time characteristics. This is possible due to an elaborate handling of redundancies and the ability to change the structure of the communication network without losing the readiness of the devices for communication. This proposed power line carrier technology (DLC) with high data rates will be proved in critical environment to be appropriate for the proposed application.

4 ICT requirements for adaptive protection applications

4.1 Introduction

Various definitions of adaptive protection have been used in literature; a few are:

a) The ability of the protection system to automatically alter its operating parameters in response to changing network conditions to maintain optimal performance.
b) An adaptive function is defined as one that automatically adjusts the operating characteristics of the relay system in response to the changing power system conditions.
c) c. Adaptive protection is a protection philosophy which permits and seeks to make adjustment to various protection functions in order to make them more attuned to prevailing power system conditions.

The need for adaptive protection arises because:

a) The system anticipates vulnerabilities and positions the system to be more robust in the event of a threat. For example, the system might adjust relay parameters during heavy loading to guard against the impact of “hidden failures.”
b) The system responds to failure events by, for example, modifying the protection system to defend against future events in case of a component failure.
c) To identify a developing emergency and respond to diminish its impact, e.g. creates islands with balanced generation and load in the event of a transient or dynamic instability .

Improvement in the utility reliability and power quality can be done by minimizing the effect of faults and interruption of supply on customers. One of the ways is to enhance the coordination between the protection systems and the switches. Fault indicators (FI) and over current protective relays are the main devices used for fault detection and isolation in distribution networks .

Technical difficulty: Fault location in distribution networks is always complex due to their non-homogeneity of line, fault resistance, load uncertainty and unbalance. The fact that a feeder has many branches adds a big difficulty in locating the fault although the fault distance from a substation could be evaluated.

4.2 ICT in adaptive protection for preventive and emergency control

According to [13], rapid switching actions, including islanding, load shedding and generator tripping, are beneficial in maintaining synchronism in unstable situations. Such use of protection system over a wide area places very demanding requirements on the communication and control system.

Figure 4.1 illustrates the basic concept. Each breaker is associated with Sensors (S), a Line Controller (LC) and the Breaker and actuating circuitry (B). The line controller can be thought of as the successor to the modern computer relay but responds to local information and provides a local control signal. In addition to a local control for each breaker, there is a Substation Coordination Controller (SCC) which receives signals from each sensor at the substation and can control each breaker at the substation. This extra level of substation logic allows for breaker action based on the state of all lines and bus bars at the substation. Wide-area control can be accomplished by communication between the SCC and a central controller (not shown) and or neighbouring substations. The communication path between line controllers (LCs) at neighbouring substations represent the action of communicating relays, both as used in current practice as well as for functions yet to be established.

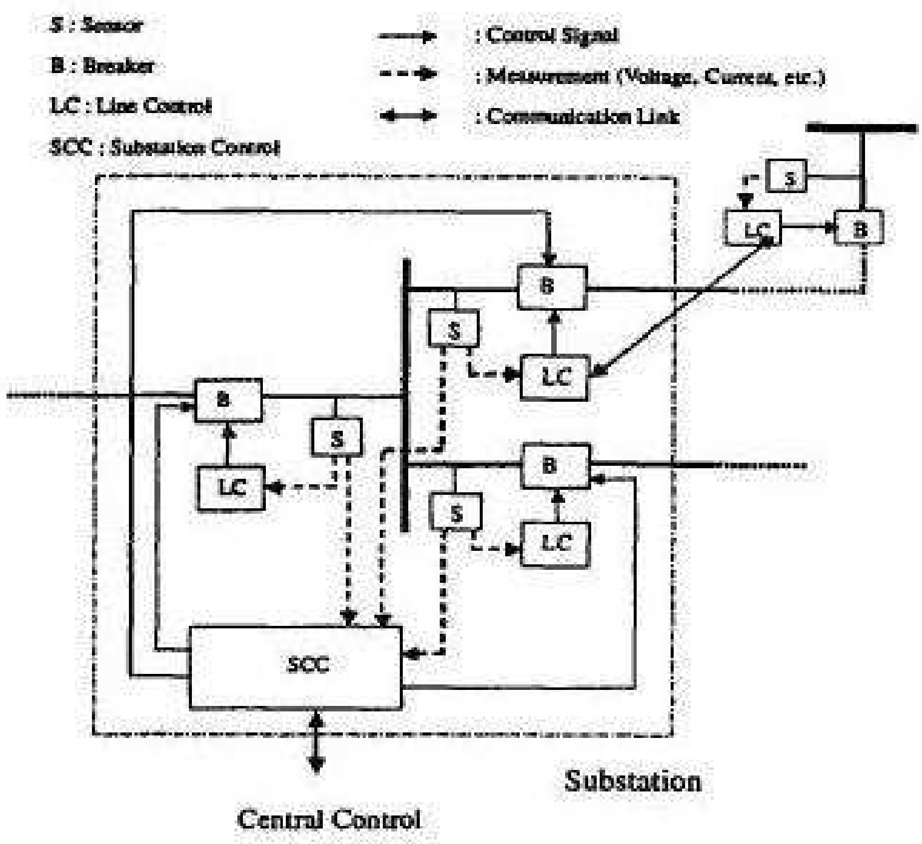

Figure 4.1: Substation coordinated control where a substation controller communicates with line controllers and a central controller to provide flexible protection and control

The role of this system is to monitor and control all the breakers in the substation. Through monitoring, the SCC system will provide alerts in the event of breaker/relay failures, including hidden failures and will assure proper settings for coordination. The system will also be given an active role to change settings upon command and to coordinate all breakers at the substation to isolate faults based on local information. An example would be to de energize a minimal portion of a substation in the event of a bus fault that may affect multiple lines.

The SSC system will be a major element in a wide area control system that involves protection devices. It must communicate with immediate neighbours for rapid tripping of far-end line faults and for primary-backup coordination. But it must also communicate with the central control system for truly wide area emergency management.

While each end of each transmission line must be protected by the autonomous operation of a relay / breaker system, the SCC can provide a coordinated response of all breakers at a substation. Further, these substations can be interconnected throughout a system to provide coordinated system response. This system can take advantage of enhanced computation (at relays in substations and centrally) and modern communications to respond not only to faults but also to threats such as unusual loading or weather. Through a network of substation controllers the protection / control system is organized over a wide area.

The different entities involved based on [13] Damborg's paper are:

a) Sensors (S),
b) Line Controller (LC)
c) Breaker and actuating circuitry (B)
d) Substation Coordination Controller (SCC)
e) Substation
f) Lines and bus bars at the substation
g) Central control system

4.3 INTEGRAL experience

According to INTEGRAL project report, one of the novel ideas that emerged recently to protect the Electric Power System (EPS) against catastrophic failures is the use of self-healing approaches (SHA). The objective of the SHA is to evaluate power system behaviour in real-time, prepare the power system to withstand eventually combination of contingencies and accommodate fast recovery from emergency state to normal state. When a disturbance occurs in the network, the power system model together with existing operation conditions, the information and communication networks are used to determine the degree of the disturbance. Once it is determined that the disturbance affects a wide area of the system, SHA break up the system into smaller parts to alter the effect of the disturbance.

SHA is expected to include the three high level functions:

a) Fault distance computation
b) Fault location and isolation by combination of Fault Passage Indicator (FI / FPI) with fault distance computation
c) Fault isolation and service restoration

Fault Passage Indicators are small devices installed along the distribution feeders. They are clamped around a cable that measures current and/or voltage signals to detect the passage of fault through their connection point. The inputs of FIs are generally the current and the voltage at the connection point. When an abnormal operation condition appears in the system such as the extreme high level of current or extreme small level of voltage rather than the nominal values, FIs will detect and signal the fault existence in the network. The residual voltage and current can be taken into account for the detection of fault. These inputs are able to be obtained from potential or current transformers from the measurement of electromagnetic field. The information resulted from FIs may be used for the location of fault in the case of permanent fault or for the location of area affected in the case of non-permanent fault. Based on the information provided, these fault indicators can be divided into two types:

a) Non-directional FIs based on a simple current criterion. They can recognize the passage of fault current but cannot determine the direction of fault. This FPI can be used for the case of important fault current like single-phase faults with impedance grounded neutral and for multi-phase faults.

b) Directional FIs based on a directional criterion which can be used for the case of small fault current like single-phase to earth with compensated or isolated neutral. They can recognize the passage of fault as well as the direction of fault seen from their connection point. They have the similar principle of detection for multi-phase fault as the non-directional FI, but they analyze also the variation of amplitude of the residual currents and voltages appeared following the single-phase to earth fault to indicate the fault direction.

A method using a combination of FIs results with fault distance computation for fault location in distribution networks was developed in GIE-IDEA (France). The advantages of this method consist in its high autonomous level for fault location with an associated ICT infrastructure. This method is very efficient in case that there are many branches and ramifications in distribution network. A distribution network is considered which is assumed to work normally in open loop operation. Firstly, when a fault appears in the network, the reclosing sequences are carried out to determine the permanent fault existence. If the reclosing procedure is not successful, the main circuit breaker is opened and an alarm is sent to the operator to inform him that the existing feeder is no more supplied. After the acquisition of information about the emergency state, the fault distance evaluation approach will be applied and the operator can know the distance of fault from the substation. Then, the signalling provided by FIs (both non-directional and directional) allows operator to determine the correct fault path among many paths corresponding to the estimated distance. Finally, the system operator can fix the exact faulty section in analyzing the information resulted from FIs, using eventually some intelligent algorithm of selection.

According to INTEGRAL project report, when a disturbance occurs in the network, the power system model together with existing operation conditions, the information and communication networks are used to determine the degree of the disturbance. Once it is determined that the disturbance affects a wide area of the system, SHA breaks up the system into smaller parts and alters the effect of the disturbance. According to INTEGRAL, the idea is to communicate with FIs and fault distance calculation devices to quickly locate the faulty section of the grid. These fault treatment processes need protection systems which are coordinated by ICT infrastructure. The signals emitted by the fault detectors can be supplied in a local way in the detector itself with help of a local ICT system that records the events or can be sent to a centralized point by a communication system. The indicator placed at strategic location along feeders, associated with the switches can provide fast location enabling reduction in outage times. This contributes to enhance service to the customers thereby improving the quality of electricity supply.

The different entities involved based on INTEGRAL Project Report are:

a) Fault Indicators (FIs)
b) Fault distance calculation device

5 ICT requirements for reconfiguration applications

5.1 Introduction

The distribution networks are the most extensive part of electrical power system and produce lots of power losses because of low voltage level of the distribution system. The goal of reconfiguration of distribution network is to find a suitable topology that minimizes the power losses of distribution system under the normal operating conditions. Under abnormal operating conditions reconfiguration of distribution network can be employed to prevent the whole or part of the system from going into unsafe conditions. This means that the grid reconfiguration can be used both pro-actively and reactively. Till date, grid reconfiguration has been implemented only in the planning phase but it can be implemented even in the operational phase with the help of ICT. ICT can be deployed to open and close various switches that can change the topology of the network.

5.2 Supply restoration experience

5.2.1 Current practice

The requirement for automated supply restoration is driven by the utilities' desire to reduce Customer Minutes Lost (CML). Its main purpose is to pick as many customers as possible and as quickly as possible while meeting criteria such as, not violating feeder and switch ratings and/or minimum switching operations. As a result, any actions taken by supply restoration must not impact negatively on CML. The supply restoration solutions should fulfil the requirements defined for safety, security, flexibility and extensibility.

There are three stages for the development of supply restoration of distribution networks, which are manual control, remote control and feeder automation. All three contain little or only simple ICT infrastructure requirements.

Manual control means that such distribution networks operate without automation. The crew needs to read fault passage indicators locally to determine which is the faulted section and then do upstream isolation, downstream isolation and restore all customers from source CB or the NOP. If there are no NOPs then restoration could be done by LV back feeding, portable generation or repairs to the fault. No advanced ICT infrastructure is required by the manual control.

Remote control is manually initiated through control of switches in a network, usually initiated at a control room; an example is the remote control of circuit breakers in primary substations or disconnectors in a network. Simple ICT infrastructure is required by such remote control.

Feeder automation is more advanced than remote control because the control of switches is not initiated by a manned control centre but by a pre configured set of logic (hard scripts) which will, under the correct conditions, operate the switches in the system to automatically reconfigure a network according to its instructions. The typical logic for these hard scripts is:

a) A trip of a circuit breaker initiates the logic

b) Determine which is the faulted section based on the special network configuration or based on fault passage indicator information

c) Isolate faulted section upstream

d) Close source circuit breaker

e) Isolate faulted section downstream

f) Close NOP

After that, the system operator may still need to send a crew to site to isolate the faulted section and restore supplies to those substations still off supply. These hard scripts can operate very fast and are easy to be used. However, they are inflexible. They can only be employed under some pre-considered conditions based on some certain network configurations and load level. Usually no ICT infrastructure is required by hard scripts.

There are many crossovers among manual control, remote control and feeder automation and presently DSO are often using all of them simultaneously to restore electric power to out-of-service customers when a fault occurs in a network.

5.2.2 Future perspective

The smart grid perspective is to move to a smarter system which will take over some of the responsibilities of system operators. The supply restoration function is an event-driven function that is triggered when a fault is detected in the power network. Unlike voltage control, the input required by the supply restoration function of smart grid management is real time measurement and fault alarms descriptions which can be summarized as follows:

- Circuit Information (steady-state information): “From” and “To” bus ID and the thermal limit
- Switchgear Information: Type, location, rated normal current and pre and post fault Open/Close status of each switchgear.
- Fault Information: “From” and “To” bus ID; ID of the tripped circuit breaker
- Backup Feeder Information: Available post-fault spare capacity of backup feeders
- Pre and post-fault V and I at remotely controlled switchgear
- Pre and post-fault output (I ,or P&Q) of distributed energy resources
- Protection settings

The output of the supply restoration will be a control message sent to switchgear, NOP or CB, etc. All these information exchanges require a more advanced ICT infrastructure.

6 Industrial state-of-practice

6.1 Introduction

This section provides an overview of the ICT employed in various projects that relate to the intra grid management in the context of smart grids that are implemented or about to be implemented by the industries like PPC and ENEL.

6.2 PPC experience

Industrial applications based on ICT for intra grid management are not yet widely introduced in the Greek power system. There are at the moment several pilot projects running in PPC relating to Smart Grids or Remote Metering.

6.2.1 Intra-grid management on the automatic metering system

PPC has very recently installed an Automatic Metering Reading (AMR) system and a corresponding Energy Data Management (EDM) system for the MV customers. This system is used for data collection and for billing purposes**.** Intra-grid management is also possible through this AMR system. The system actually allows for the development of several custom made levels of customer management. However this is exercised only on a limited level due to restrictions in the regulating environment of the Greek energy system. The main parameters of the AMR system are:

The distribution of metering points (MP) are hereinafter listed:

- Northern Greece: 2333 MP
- Central Greece: 1079 MP
- Attica: 2923 MP
- Southern Greece: 1097 MP
- Total: 4802 MP

The communication mode is:

- 47% GSM (Global System for Mobile communications)
- 47% GPRS (General Packet Radio Service)
- 6% PSTN (Public Switched Telephone Network)

The communication protocol used is DLMS. The desired distribution is 30% GSM/PSTN and 70% GPRS, but this also depends on the location of the metering points, the signal strength and the provider's network quality.

The readout average communication time is:

- For Load Profile readings (2 per day)
  - GSM-PSTN 65 seconds
  - GPRS: 30 seconds
- For Billing Registers
  - GSM-PSTN: 40 seconds
  - GPRS: 24 seconds

The communication system is depicted in Figure 6.1

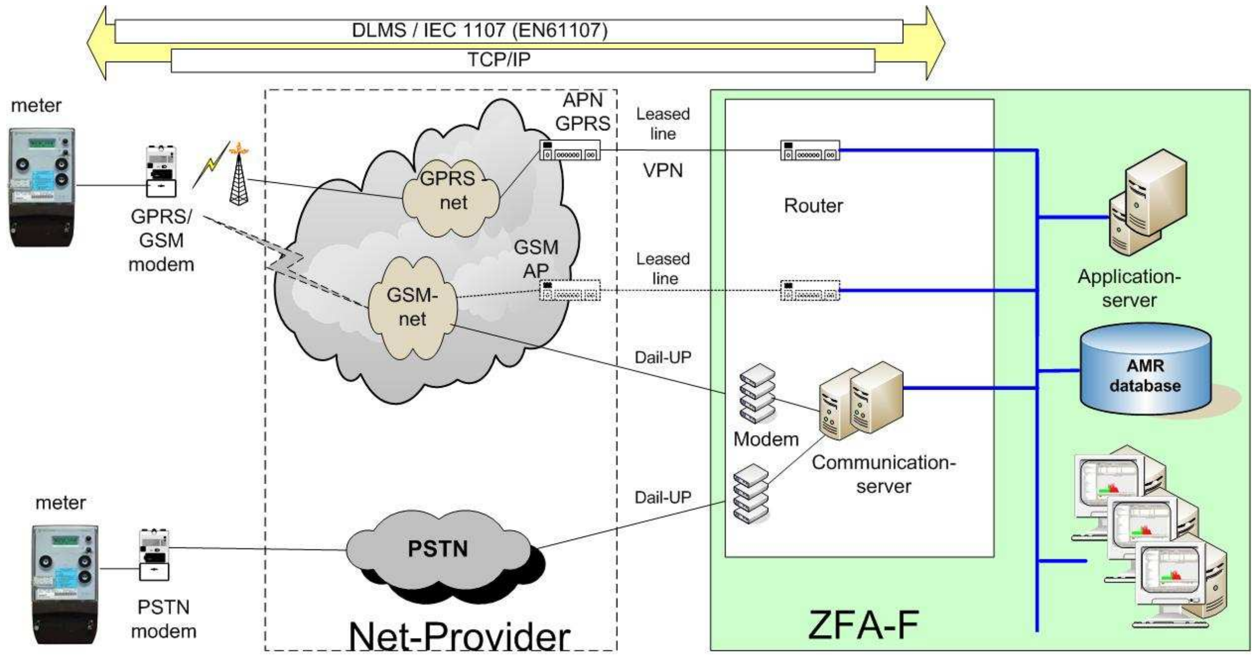

Figure 6.1: The communication system deployed by PPC

6.2.2 The smart grid Larissa project

The project in Larissa is the first Smart Grid project in Greece and one of the largest and most modern in Europe, designed by PPC in cooperation with partners (Siemens, Amperion) for the medium voltage network. Covering more than 100 km of MV network with applications ranging from load management to fault detection and automatic meter reading, this project is the state of the art in energy management and automation. The smart grid network was installed in two medium voltage lines starting from the ultra-high voltage substation of PPC just outside the city of Larissa. These two lines named R-240 and R-250 are of mixed use, feeding both agricultural loads and villages in the area.

The task of the project is to electrify this agricultural region in a way that the demand will meet the supply under the harsh Greek summer conditions. This task is not an easy one as it involves the management of a wide spread medium voltage network with greatly increased amounts of power during the summer, a season most difficult for PPC when temperatures reaching at 40 degrees Celsius bring the air-conditioning loads in Greece at their highest.

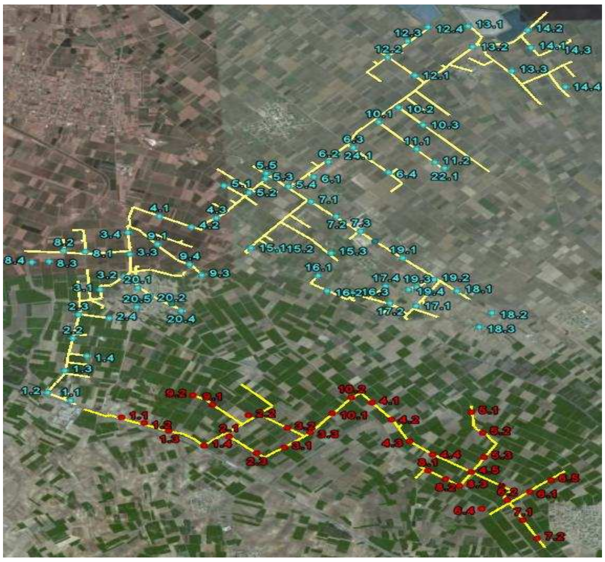

Figure 6.2: The Larissa network

The smart grid network created in this area features embedded telecommunications on the medium voltage lines based on patented Broadband over Power Line (BPL) technology and a vast array of end devices including switches and power quality measuring sensors.

The network installed is comprised of 105 BPL units that are installed on the MV network thus creating a backbone of connectivity to the substation. The units are installed starting at the first pole outside of the ultra high voltage substation and one is installed every 700 to 800 meters until the end of the MV lines. The first unit, called the Injector unit, is connected to the Substations Control Centre via Wi-Fi and then to the internet / PPC intranet via a HDSL provided by the fibre optics POP in the substation.

Each of the following units, called Repeaters, extend the signal for the next hop and create a wireless hotspot around them for users and devices to connect to the main network. The Wi-Fi is under the IEEE 802.11 a, b and g and the security methods used are both WPA2-PSK and MAC authentication for the network devices. The wireless is also used for backup purposes between units in case of cable failure. In that way a meshed wireless connectivity area of approximately 100 km^2 is created where load switching units and other installed equipment (sensors, meters etc) can seamlessly connect to any of the units.

As far as switching devices are concerned 200 are connected in customers that PPC indicated and are remotely monitored from the Control Centre via OPC and over the BPL backbone and Wi-Fi last mile connection. This reduces the cost of installation significantly and reduces the complexity of expanding to more switches (or any other devices) in the area since the coverage and backbone network are already installed.

Apart from the switching equipment 45 remotely operated meters are installed in consumers in the villages of Halki and Mellia in order for PPC to evaluate the AMR opportunity over BPL. They too are connected via the Wi-Fi network on the BPL backbone.

From a telecommunications point of view in the network, are also installed two surveillance cameras to secure sensitive parts of the network and 10 VoIP networks are handed out to PPC personnel to use instead of mobile phones while in the area of coverage. Wi-Fi internet connectivity is also available to authorised PPC personnel but not to the public in the villages covered since PPC has decided not to engage in that market as of yet.

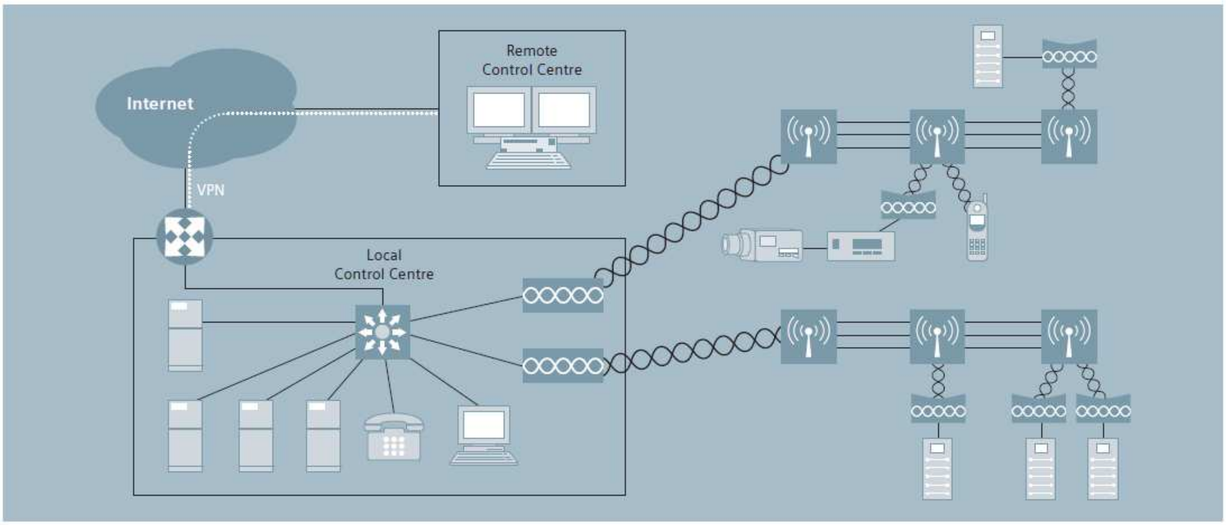

Figure 6.3: Network diagram

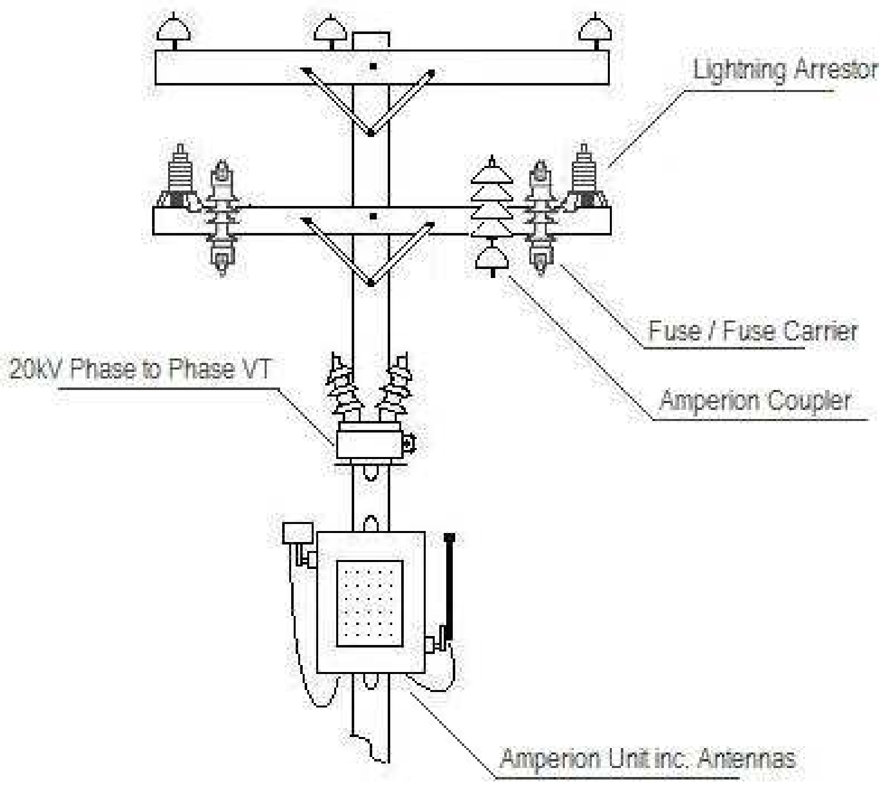

Figure 6.4: Unit installation

The applications delivered in the context of this project include:

- Load management (remote control switches that control the agricultural loads within milliseconds)
- AMI (Automatic Meter Infrastructure)
- RF noise level measurements (fault prediction)
- Wireless cameras surveillance
- Measurement on the LV grid (voltage, current, & temperature).
- Telecom applications (VoIP, internet etc)

The project did not have any negative impact on the proper operation of the power network.

6.3 ENEL experience

6.3.1 Voltage regulation

Voltage regulation today

Voltage regulation in place is the current sensitive regulation mode which varies the distribution transformer tap changer position (thus the voltage at the MV bus bar) as a function of the current which flows through the HV/MV transformer. The regulation is inhibited when there is an inversion of the current into the transformer. This kind of regulation does not perform well when Distributed Generation (DG) is connected to the MV feeders. In fact, being the voltage regulated on the basis of the current circulating in the HV/MV transformer, it is implicitly assumed that a reduction of the current in the transformer implies a uniform reduction of the power required from the loads on the MV feeders at the MV bus bar. This criterion is not valid anymore in case of Distributed Generation along the feeders, when a reduction of current in the transformer may imply an unacceptable reduction of the voltage on the feeders where DG is not present.

An example is shown in Figure 6.5, in absence of the generator on line 3, the voltage profiles along the feeders are so that voltage in all the network nodes is kept within the limits set by the standards, having set the voltage at the MV bus bar at 1.06 Vn (Vn is the nominal voltage) (red profiles). In presence of the generator on line 3 the regulator measures a minor current in the transformer thus reduces the voltage of the MV bus bar to 1.02 Vn. As a consequence, the voltage profiles on feeders 1-2 (where there is no DG) will proportionally reduce and it could result that not all the nodes in feeders 1-2 have the voltage within the limits. The voltage profile in line 3 improves and all the nodes in line 3 have the proper voltage.

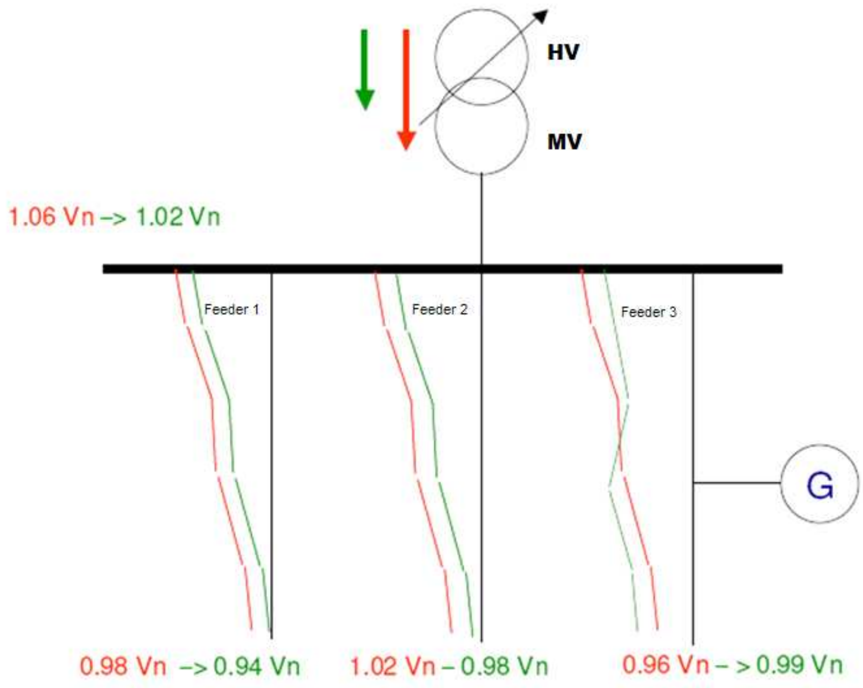

Figure 6.5: Voltage profiles in absence and presence of DG

In conclusion in the current voltage regulation mode ICT is basically limited to the intelligence in the primary substation. There is no communication with the distributed generators nor the loads. The input parameters for the regulator are the voltage at the MV bus bar and the current in the HV/MV transformer, which are already available in the HV/MV substation. This strategy performs correctly in case of passive MV grid, while a new system has to be implemented in order to ensure the proper regulation in active grids.

Voltage regulation tomorrow

The need of ICT is much greater. The integration of distributed generation and demand side requires the study and design of an appropriate voltage regulation system that utilizes communication between the HV/MV substation and the generators and loads. This communication will have to be highly reliable, secure and “real time”. This system will ensure a better voltage profile to all the users connected, both at the MV and LV network and will aim as well to the reduction of network losses, achieving the reduction of injected energy and CO_2 emissions. It will facilitate as well the connection of new distributed generation to the MV network.

There are two steps to achieve the objective. The first step is a new strategy that allows the control of voltage in all the nodes of the network supplied by a MV bus bar, even in presence of distributed generation, without controlling loads and generators. The main purpose is to maintain the value of the voltage within the limits established by the standards; this modality does not need still any communication between HV/MV substation voltage regulator and distributed generation nor loads, because the control variables are only the ones already available in the primary substation. It is substantially an extension of the current system, with the difference that it is able to manage the presence of distributed generators, using more sophisticated strategy and algorithms and taking into account the real configuration of the network and as inputs the value of the voltage at the MV bus bar and the value of the currents at the head of the MV feeders. From the ICT perspective this evolution impacts on the local intelligence in the substation.

The second step is to implement an even more sophisticated voltage regulation system that allows the control of the voltage in all points of the MV network in presence of distributed generation, through the control of distributed generators in the field; furthermore, the objective is not only to maintain the value of the voltage within the limits, but to obtain an optimal (sub-optimal) voltage profile along the network. This profile could be set in order to minimize the network losses or to maximize the margins towards the standard voltage limits, allowing a greater number of generators to be connected, the reduction of losses, the improvement of service quality, the reduction of the energy input to the distribution network; the system is also able to manage the disconnection of distributed generation in the event of unwanted island operation (loss of primary feeding grid), in a efficient and reliable way, while the current systems are little efficient in presence of great penetration of distributed generation.

This system works with more control variables, some of them coming from the field, that are to be known in real time by the automatic voltage regulator: connection status of generators, voltage, output active and reactive power at the connection point of generators; this means that the voltage control system located in the HV/MV substation must be interfaced with controllable distributed generators and as an example periodically be able to acquire synchronously the voltage measured at the generators connection point and rapidly, synchronously as well, provide generators with indication of variations in reactive power in order to re-establish the correct value of the voltage along the line. In this case communications between the control equipment in the primary substation and the interface equipment at generators represent a critical issue from the technological point of view. Different communication media are available, they have to be selected carefully in order to have high reliability, security and low latency.

7 Conclusions

A survey of the different ICT-approaches that can be applied for the better management of smart grids has been presented. This report dealt with those approaches for the technical management of smart distribution grids that require information and communication technology and which allow the society to have a better, more efficient usage of electrical energy. Exemplary topics of voltage control, adaptive protection, reconfiguration have been dealt with. It has been identified that the control and coordination of distributed energy resources (DER), which are spread throughout the distribution network require a suitable communication between the different generation units and the distribution network operator (DNO). This communication must be bidirectional (including control signals, state signals, measurements and alarm signals) and sufficiently fast, since the introduction of excessive time delays into the control system can destabilize the entire electric grid, jeopardizing the quality and safety of power supply.

Main functionalities provided by DG units and the main features of communication channels namely data transfer rate and data volume, response time (latency of packets), application priority, reliability of the communication channel, availability of communication channel and security and privacy were identified. Suitability of the various telecommunication technologies based on the function assigned to DG units is enlisted in the report.

When adopting coordinated voltage control as suggested in DEMONET project report, the necessary ICT entities involved are a central controller located at the substation, at the OLTC transformers, at selected DG units that are there in the field and in chosen critical points in the network. When adopting coordinated voltage control as suggested in INTEGRAL project report; the entities involved are DG units, Pilot buses and Substations. According to the Aura-NMS experience most voltage control function contains two main sub-functions namely Identify Voltage Excursion (IVE) and Voltage Excursion Relief (VER). All these call for heavy communication needs.

According to the project on power quality [12], reliable operation of safety critical applications requires high level communication technology and data transmission regarding short response times, time synchronisation and robustness against electromagnetic distortion. Thus, efficient pre-processing and data compression with use of encryption algorithm is required. Besides, for this application a high number of distributed components have to be monitored, coordinated and controlled, whereas a lot of plants in the energy sector are not connected to a communication network. Therefore, the use of an economic communication technology is required and the use of the power line for communication is the natural and most appropriate solution. Towards this purpose the project employed the distribution line carrier DLC-2000 system from iAd, which is chosen as the backbone of the proposed system. The advantages of DLC quoted by the project are elaborate handling of redundancies and the ability to change the structure of the communication network without losing the readiness of the devices for communication. Also the project report opines that the proposed power line carrier technology with high data rates will prove to be appropriate for the proposed application.

The various definitions of adaptive protection that have been used in literature are presented in this report along with the need for adaptive protection. The different entities involved based on Damborg's paper are: sensors, line controller, breaker and actuating circuitry, substation coordination controller, substation, lines and bus bars at the substation and central control system. According to INTEGRAL project report the different entities involved are fault indicators (FIs) and fault distance calculation device. The idea is to communicate with FIs and fault distance calculation devices to quickly locate the faulty section of the grid. These fault treatment processes need protection systems which are coordinated by ICT infrastructure. The indicator placed at strategic location along feeders, associated with the switches can provide fast location enabling reduction in outage times. This contributes to enhance service to the customers thereby improving the quality of electricity supply.

The supply restoration function is an event-driven function that is triggered when a fault is detected in the power network. Unlike voltage control, the input required by the supply restoration function of smart grid management is real time measurement and fault alarms descriptions. The output of the supply restoration will be a control message sent to switchgear, NOP or CB, etc. All these information exchanges require a more advanced ICT infrastructure.

Automatic Metering Reading (AMR) system and a corresponding Energy Data Management (EDM) system for the MV customers recently installed by PPC has been described in this report. According to PPC Intra-grid management is possible through this AMR system. The Communication protocol used is the DLMS and the desired distribution of communication is 30% GSM/PSTN and 70% GPRS. One of the largest and most modern smart grid network in Europe, the Larisa project, comprised of 105 BPL units that are installed on the MV network thus creating a backbone of connectivity to the substation. The first unit, called the Injector unit, is connected to the Substations Control Centre via Wi-Fi and then to the internet / PPC intranet via a HDSL provided by the fibre optics POP in the substation. Each of the following units, called Repeaters, extend the signal for the next hop and create a wireless hotspot around them for users and devices to connect to the main network. The Wi-Fi is under the IEEE 802.11 a, b and g and the security methods used are both WPA2-PSK and MAC authentication for the network devices. The wireless is also used for backup purposes between units in case of cable failure.

ENEL proposes two steps of voltage control and the first step allows the control of voltage in all the nodes of the network supplied by a MV bus bar, even in presence of distributed generation, without controlling loads and generators. From the ICT perspective this evolution impacts on the local intelligence in the substation. The second step is to implement an even more sophisticated voltage regulation system that allows control of the voltage in all points of the MV network in presence of distributed generation, through the control of distributed generators in the field. The objective is not only to maintain the value of the voltage within the limits, but to obtain an optimal voltage profile along the network. As this system works with more control variables, communications between the control equipment in the primary substation and the interface equipment at generators represent a critical issue from the technological point of view. Different communication media have to be selected carefully in order to have high reliability, security and low latency.

	Voltage control	Adaptive protection	Reconfiguration
Research in university and industrial laboratories	1) DEMONET 2) INTEGRAL 3) AURA-NMS 4)Research at ENEL	1) A paper “Adaptive protection as preventive and emergency control” by Damborg et al., 2) INTEGRAL	1) Research on supply restoration
Developments and realizations in companies	1) “Decentral monitoring and enhancement of power network quality by means of power electronics and new ICT” by iAd, Siemens, TUM & ELSYS 2) AMR by PPC	1) AMR by PPC	1) AMR by PPC
Pilots on smaller scales	1) Larissa project by PPC	1) Larissa project by PPC	1) Larissa project by PPC
Deployment on larger scales	-	-	-

Thus from the above table it can be concluded that there are many research and pilot projects that are being done in the field of voltage control for intra-grid management with DG included where as the R&D is substantially low for ICT in grid reconfiguration. Also, the large scale deployment of ICT in any of the exemplary aspects of intra grid management namely, voltage control, adaptive protection and grid reconfiguration is almost non-existing as of now. Hence, there need to be more R&D work with regard to ICT in intra-grid management that has to be carried out along with the implementation of various ideas developed from the R&D work in pilot projects.

In conclusion, the ICT characteristics that need to be focussed on for intra-grid management are data transfer rate and data volume, response time (latency of packets), application priority, reliability and availability of communication channel, security , privacy, scalability, interoperability and robustness of the type of communication deployed for grid management functions like voltage control, adaptive protection, grid reconfiguration etc.

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