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## EXECUTIVE SUMMARY

This deliverable defines the IDE4L automation architecture concept.

This automation concept consists of the definition of the actors, functions and links that realize the smart grid concept outlined in D2.1, through the applications of WP4-6.

The automation concept supports the coherent development of the monitoring, control and protection developed in WPs 4-6, and it will be detailed in T3.2, to yield the IDE4L automation architecture.

In this document we synthesize the high level architecture requirements of the applications (conceptualized as SGAM Use Cases and received from WP4-6) that lead to a draft architecture with 31 actors and 21 functions, and the links between actors and functions. This draft architecture constitutes:

- Common background for the application development (applications are going to developed according to this structure)
- A format ready for architecture design following standards (in particular the IEC 61850 series) and using SGAM templates and tools (activity of T3.2, content of D3.2)

This automation concept and related draft architecture build on top of the findings of previous FP7 projects INTEGRIS and ADDRESS. From these, IDE4L inherits the distribution of technical functions (formulated in INTEGRIS) and the market orientation (broad participation proposed in ADDRESS). These architectures were synthesized in an IDE4L starting point architecture then advanced with the other stakeholders besides the DSO, namely TSO, Commercial Aggregator and service providers.

The implementation of the IDE4L automation concept requires technical developments in the automation of primary and secondary substation, feeder, DER and LV systems. Such developments, detailed in this deliverable, are: in communications (thorough implementation of existing standards, starting from IEC 61850), advanced and fully distributed functionalities (like fault location, isolation and service restoration schemes or coordination of distributed voltage control), functions and devices for the customers' premises.

The outcome in this deliverable to other WPs and to T3.2 consists of:

- a common draft architecture for the applications, which will use actors and functions as defined in this deliverable
- a process, to jointly develop architecture, applications and demonstrations
- assessment metrics of the architecture
- definition of critical technology advancements

In particular, according to the process, first UCs of the applications will be detailed further (using the SGAM template) to determine function triggers, function effects, function steps. Then each function will be built up from IEC 61850 logical nodes, logical communications will be defined, device allocation and physical communications will be finalized. The part of the architecture outside the substation, that is, outside the field of applicability of IEC 61850 will be formalized with the other applicable standards. In particular, the home energy management systems and smart metering will be mapped to IEC 62056 (DLMS/COSEM) and network model will be mapped to the Common Information Model (CIM). Business functions, such as flexibility table exchange, for which there is still no clear standardized solution, are expected to yield useful information on standardization gaps.

Fall out achievements of the work presented here are:

- Demonstration of the use of SGAM framework for architecture development
- Generation of UC formalization, saved in the UC online repository, ready for possible consideration by CEN-CENELEC-ETSI Smart Grid Coordination Group for standardization purpose

## 1. INTRODUCTION

This deliverable reports the results achieved by WP3 in T3.1: the automation concept for the active distribution grid. With automation concept we intend the definition of the actors, their links, and the functions that the actors must implement, to fulfill the requirements of the active distribution network in the next 15 years. The active distribution network concept is defined in D2.1, together with the requirements.

### 1.1 How to read this document

The present deliverable aims at defining IDE4L concept of automation architecture, meaning the architecture needed to correctly perform and integrate all the use cases (e.g. voltage control, monitoring of the grid, DERs participation to the market) defined in IDE4L, which cover a large part of the functionalities of the smart grids.

Chapter 1 reviews the main developments of other European projects regarding the architecture of the automation grid; limits and innovations of each project are highlighted. This clarifies the starting point of the work presented here.

Chapter 2 explains the working approach, which is in itself a significant contribution of the IDE4L project. In particular, we show the incremental procedure that extends beyond this deliverable and that develops the architecture based on the mapping of use cases onto the Smart Grid Architecture Model (SGAM) framework [13], adapted to the particular needs of IDE4L project.

Chapter 3 illustrates the main content of the deliverable: the concept of IDE4L automation architecture in form of actors, functions, and communication links. A hierarchical structure facilitates the grouping of functionalities from general (e.g. monitoring, control, business functions) to specific applications, up to the finest level of granularity, the primary use cases (presented in Annex 6).

Chapter 4 links in to Task 3.2, that is the development of the architecture, through the definition of requirements in four key areas: technologies and standards for automation, communication infrastructures, monitoring systems and control centers.

### 1.2 Scope of the work

This section explains the goals of the WP3 within the global objectives of IDE4L project, which are:

- Develop advanced distribution network automation system including utilization of flexibility services of DERs and their aggregators
- Develop advanced applications that enable monitoring and control of whole network
  - Fault location, isolation and supply restoration (FLISR)
  - Congestion management and voltage control
  - Interactions between distribution and transmission operators
- Demonstrate the automation system and selected use cases for active distribution network

In this context:

WP3 yields the definition of the automation architecture that supports the services, monitoring, control and protection applications developed in the other WPs to achieve the IDE4L goals.

Using this one reference architecture, the applications are better integrated, and share at best data and information. The common architecture enables reusability, within the project and beyond, of the developed applications. It constitutes common ground to facilitate comparison of different scenarios and solutions, as well as it facilitates setting and verifying implementation requirements that the applications.

The architecture addressed here mainly covers **domains of customer premises, DER and distribution, zones of process, field, station and operation, and interoperability layers of component, communication, information and function**. The proposed architecture receives input from and provides output to the business layer, but it does not specified use cases for DSO's control center and commercial aggregator interapplication information exchange at enterprise or market zone levels. Transmission domain is included with very limited scope concentrating distribution network PMU data exchange with TSO.

With the architecture we intend the description of the data and computation infrastructure, data flows, communication links and protocols, and equipment types, as it is needed by actors to operate, and for functions, which support the applications, to be implemented in a real setting.

The outcome of this first deliverable of WP3 is the definition of the IDE4L automation architecture concept, which consists of the definition of the actors, functions and links that are necessary to the relevant portion of the smart grid concept outlined in D2.1 [1].

This automation architecture concept will then be used by WP 4-6 to implement, in a consistent manner, algorithms, functions and integrate data and devices. From the standpoint of developing the architecture, this means detailing the automation architecture until it is fully defined. This deliverable provides the framework and operative documents with which the information from WP 4-6 are collected and turned into detailed architecture.

From a broad perspective, the IDE4L transformation is the end of “oversizing” of the power infrastructure and the beginning of intelligent cooperation of several electrical components that share the common goal of flexibility, efficiency, and reliability [1]. To this aim, the IDE4L grid will be able to integrate several new control schemes and algorithms for the grid management and collect information from the different actors in the management system [1].

The active network management aims at [1]:

- Ensuring safe network operation in distribution networks with DERs
- Increasing network reliability in networks with DERs
- Maximizing the hosting capacity of the existing networks with bottlenecks
- Maintaining the required level of PQ despite variable power production or consumption.

Secondary technologies and related necessary Primary technologies to be introduced in the active distribution network are clearly identified in 3.2 of D3.1 [1]. They constitute the primary factors in the novel features of the architecture introduced here, and formalized in Section 3.3 of D3.1, in particular:

- Monitoring of MV feeders, secondary substations and LV networks
- FLISR application

- Power quality metering
- Fault recording
- Sychrophasor measurement
- IEDs for substation level decision making
- Automatic voltage regulators
- Controllable DERs

These technologies are the bases of the Use Cases, extensively presented and analysed in Chapter 3 of this deliverable, based on which the IDE4L architecture is developed.

Furthermore, the perspective of the DSO as unique, fairly autonomous actor has changed since deregulation and is expected to evolve further [58]. Not only the link with pre-existing partners (TSO, Market) has tightened, but also new partners have appeared, in particular the Aggregator [1]. This implies that data and measurements will follow new paths. They will be merged and used for decision making at different levels and for different purposes. Fast changing conditions will have to be dealt with dynamically.

The communication technologies must support real-time information exchange, on which such a distributed, intelligent automation system is heavily dependent on. In this light, the use of different media, standards and redundancy in general is to be expected. The detailed architecture of the communications is not covered in this first part f the work. However, the necessary developments in terms of technology and standards are discussed in Chapter 4, for communications as well as for substation automation, control centres, measurement and monitoring infrastructure.

The objective of WP3 is to develop the automation architecture in line with the guidelines of the EU Working Group on Smart Grid [23] and in compliance with the existing standards and their foreseeable developments, in particular the IEC 61850.

## 1.3 State of the art of Distribution Grid Automation

State of the art of distribution grid automation:

- State of the art of architectures for distribution from other projects,
- Some reference about the current automation systems of the DSOs (already deployed).

### 1.3.1 ADINE – Active DIstribution Network [2]

#### *Concept and Architecture*

The aim of Active Network Management (ANM) is to add more flexibility for network management in order to utilize existing network more efficiently. When a DG unit is connected to weak distribution network, there may appear extreme loading conditions which restrict the size of unit remarkably. If the cost of network reinforcement to achieve the firm network capacity for the DG is large compared to the probability of extreme conditions, it may be favorable opportunity to utilize e.g. occasional production curtailment or reactive power support of DG to increase network hosting capacity for DG. To implement the ANM concept a collection of technical solutions are needed to bring necessary features for protection and control systems.

Existing systems like SCADA, Distribution Management System (DMS), substation and distribution automation and Advanced Metering Infrastructure (AMI) should be the basis for ANM. Today the controllability of distribution network has been mainly realized at primary substations while the utilization

of distribution network automation is concentrating on network reliability enhancement. The monitoring and telemetry of MV and LV networks is still very limited although the number of secondary substation monitoring devices and AMI is increasing rapidly. The local intelligence at substation and other locations via processing and communication capability of intelligent electronic devices (IED) is also increasing. The monitoring and control requirements of ANM will utilize these new technical solutions to process and exchange information within a whole distribution network.

The ANM architecture has a hierarchy of protection, decentralized (primary) control, and area (secondary) control levels. Area control level may be used to coordinate individual resources by adjusting the set-points of decentralized controllers or protection devices. The basis of area control level is the control center information systems and communication between control center and decentralized equipment. The information systems consist of SCADA, DMS and Relay setting tool used in network operation and network information system (NIS) used in network planning. Centralized functions should have a network wide view of distribution network status provided by SCADA, extended by AMI to reach information from LV networks, and integrated to other information systems via DMS including updated distribution network model (e.g. status of manual disconnectors). Decentralized control level operates automatically based on local measurements. The operation of protection system is fast and autonomous.

### **Demonstrations**

The extraordinary feature of this project was to develop and demonstrate the ANM method and the enabling solutions simultaneously. These solutions were protection relay and fault location applications, software prototype of coordinated protection planning, voltage control of small-scale microturbine, centralized voltage control on SCADA/DMS and new generation medium voltage static synchronous compensator (STATCOM). Second, the concept of ANM was demonstrated in real-time simulation environment which includes models like DG, STATCOM and distribution network, real devices like control, protection and communication devices and SCADA/DMS and relay configuration and setting software in one combined demonstration.

The project demonstrated that distance protection may be helpful in challenging protection situations with DG. However, it has to be noted that careful protection setting planning is needed in many cases. It was also demonstrated that loss of mains (LOM) protection utilizing fast communication gives superior results compared to traditional LOM protection on generator location. Both in the laboratory and on field tests the project has shown that existing fault location methods call for improvements when DG with substantial short circuit current is added. In addition, new methods for earth fault location in compensated networks have shown to be very valuable but limitations exist.

The project aimed at bringing voltage control with DG units closer to commercial introduction by demonstrating voltage control capabilities of microturbine connected at the low voltage level. Due to the combination of small converter rating in the kW range and the resistive network impedance at low voltage level, it is not possible to control voltage in the network with the microturbine converter. The project demonstrated how network connection through series inductance makes possible for a power electronic converter to control voltage for selected loads. The solution effectively rejects both voltage dips caused by switching of local loads and disturbances originating in the feeding network.

The real life demonstration has shown that the STATCOM can be exploited as an excellent product for the stabilization of grid voltage. It enables the integration of DG also into weak networks. Due to the very dynamic response on variations in the electricity network (e.g. low voltage ride through) or load changes, it

can be used as a flexible and powerful solution for flicker and/or harmonics cancellation. The developed and demonstrated new generation STATCOM is capable of filtering flicker, harmonics and compensating reactive power. The new STATCOM can also be used for mitigating voltage dips and for controlling the voltage level of the distribution network. The voltage source converter acts as voltage source that is capable of controlling the voltage phase, frequency and magnitude at its interconnection point.

The settings of protection relays should be coordinated to adapt protection settings to changes of network configurations and DG connections. The coordinated protection planning function of NIS, developed and demonstrated during the project, will analyze and plan protection settings for protection relays. Two of the key features of the method are a procedure for studying protection aspects in proper sequence, and a novel method for defining the protection requirements for a new DG unit in an unambiguous manner. The fault calculations of NIS as well as the modelling of DG units were also developed.

Coordinated voltage control requires a central voltage controller above local voltage control. The central voltage controller is an application on SCADA/DMS which is used to control the set points of primary substation automatic voltage control relay and DG automatic voltage regulator. The algorithm contains also a restoring part that is used to restore DG power factor to unity always when possible and to normalize network voltages when the voltages in the whole network have remained in an unusually high or low level. The inputs of the coordinated voltage control algorithm can be either estimated or measured. The state estimation can be included in DMS and its accuracy has a crucial role in coordinated voltage control. By implementing the coordinated voltage control as a function of DMS encourage distribution network operators to take it into use. The real network demonstration was successfully conducted.

### 1.3.2 ADDRESS – Active Distribution network with full integration of Demand and distributed energy REsourceS [3]

ADDRESS (2008 - 2013) was a large-scale Integrated Project co-founded by the European Commission under the 7th Framework Programme, in the Energy area for the "Development of Interactive Distribution Energy Networks".

One of the main project outcomes of the project was the development of the Aggregator concept. This concept is used for the implementation of the "Active Demand", i.e. for enabling the active participation of domestic and small commercial customers in the power system markets and in the provision of ancillary services.

According to the proposed architecture, the Aggregators are the mediators between the consumers and the markets. Their role consists of:

- Collecting the requests and the signals coming from the markets and the different power system participants.
- Gathering the consumption flexibilities, by sending price or volume signals and offering the services to the interested participants, through the markets.

Figure 1.1 shows the scope of the project and an overview of the architecture. According to the project ADDRESS, the Aggregator is defined as the player, which buys and sells energy and controllable power (flexibility) in the electricity markets, by modifying the consumption patterns of their customers. This modification is achieved by different incentives that are sent to the consumers, in order to change their

consumption level at specific time intervals. Therefore aggregator sells a deviation from the forecasted level of demand, and not a specific level of demand.

The Aggregator will communicate with the consumers by means of the so called Energy Box (EB), which becomes the gateway between consumer and Aggregator, and is in charge of the coordination of load, generation and storage at consumer facilities. EB will be in charge of optimizing its aggregated profile according to consumers' objectives and information received by the Aggregator (price and volume signals).

The technical feasibility of the AD products and the overall stability of the Power System are ensured by the DSO. In the context of ADDRESS, new functionalities are introduced to the DSO, who is now considered as the Technical Aggregator. These tools are essentially:

- The “Off-Line” validation tools, which are used for AD product validation after gate closure (when this one is not “close to real-time”) assuming some possible configuration and forecasting the operating conditions of the distribution system.
- The Real-Time Validation (RTV) tool, which is used by DSO before giving his consent to the request of an AD product by the TSO or other deregulated players, which is activated close to real-time and therefore which refers to the actual configuration and operating conditions of the distribution system.

ADDRESS project conclusions, which also included a demonstration part in Italy, France and Spain, were mainly addressed to regulators. Recommendations about the future role and functionalities of an aggregator, the implications of the new paradigm for System Operators, consumers and other agents, including manufacturers and providers of communication services were produced. Relevant power system actors such as Eurelectric (the association of the electricity industry in Europe) use ADDRESS research results as a reference when discussing flexibility markets design [48].

Having that in mind, the development of the aggregator concept within the IDE4L project is mainly following the technical guidelines defined in ADDRESS, since it concentrates the most relevant state of the art on the aggregation field at European level. On top of this, IDEAL T6.2 (within WP6) will focus on the following research contributions on the commercial aggregator topic:

- To improve some of the ADDRESS technical procedures identified as further research in the project conclusions (mainly focused on “flexibility forecast” and “market bidding” as described later on).
- To develop an aggregator model that complies with the last European Regulations (DCC) [49] and with the IDE4L Advanced Distribution Network concept.
- To adapt the aggregator models developed within IDE4L project to the Spanish electricity market regulatory framework.

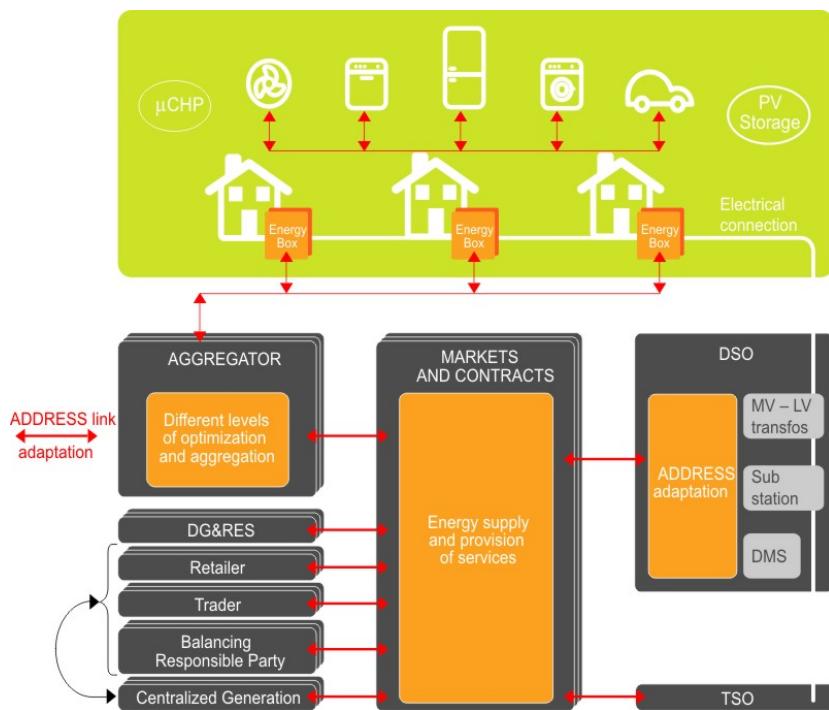


Figure 1.1: ADDRESS architecture [3].

### 1.3.3 INTEGRIS – INTElligent GRId Sensor communications [4]

Smart Grids are a convergence sector where new electrical engineering applications are enabled by new communication infrastructures specifically defined to reach HV/MV and MV/LV transformer substations and customers. This communication infrastructure has to fulfill requirements set up by grid operation and, at the same time, it has to be a balanced tradeoff between investments and benefits.

INTEGRIS tries to give an answer to this demand. INTEGRIS is a European project co-funded by the European Commission within the 7th Framework Program – ICTEnergy-2009 under grant no. 247938. Because it is an ICT-Energy project it considers communication challenges as well as new electrical concepts and algorithms for the grid management.

INTEGRIS proposes – as its first goal – an open communications platform, able to integrate several communication technologies to cope with both traditional distribution grid management and new Smart Grid requirements. The mix of technologies – such as Broadband Power Line (BPL), Wi-Fi and Fiber Optic (FO) – has been selected to guarantee a tradeoff between investments and benefits. In fact, integration of those technologies (and any other that could be considered) allows obtaining a more reliable and performing communication network. Narrowband wireless technologies, such as RFID and ZigBee are used for the collection of monitoring data within the substation.

This concept was applied in two cases: the distribution grid of A2A Reti Elettriche SpA, in the city of Brescia (north of Italy) and the grid of Endesa in Barcelona (Spain). Figure 1.2 refers to the Italian demonstrator. The Italian field demonstrator – as a whole – is a MV and LV network. The MV side is composed of 13 secondary substations connected to 3 MV feeders (Line 1, 2 and 3) from a primary substation. A communication infrastructure – based on a mix of technologies – was designed and overlaid upon this MV grid. Primary substations were already connected to the control center via a FO ring. The FO network was extended to connect 3 other secondary substations by building a new ring. Those secondary substations were chosen as the best trade-off between time and cost of the cabling and the benefit in terms of

enabling network management services. Ten other secondary substations were connected by using the BPL over MV cables and the last one secondary substation via a Wi-Fi link. The LV part of the pilot was formed by two LV feeders from the SS 1056, serving 14 customer in a condominium (Line 6) and 42 customers in independent houses. For the sake of the test, the condominium and 6 single customers' premises were equipped with a LV-BPL and smart meters.

Once a communication network has been overlapped to the electrical grid, a second goal of INTEGRIS is to design and test new electrical applications which were precluded before, such as an integrated monitoring (e.g. voltage, current, active and reactive power – per each phase – from primary substations, secondary substations and customers/generations) of the grid and a deep controllability of the LV grid. INTEGRIS proposes to implement these applications taking into account that:

- the amount of data to handle will increase exponentially with respect to the present and some procedure to optimize the data flow should be considered,
- the benefit of an integrated grid management will be exploited only if it makes reference to open standards.

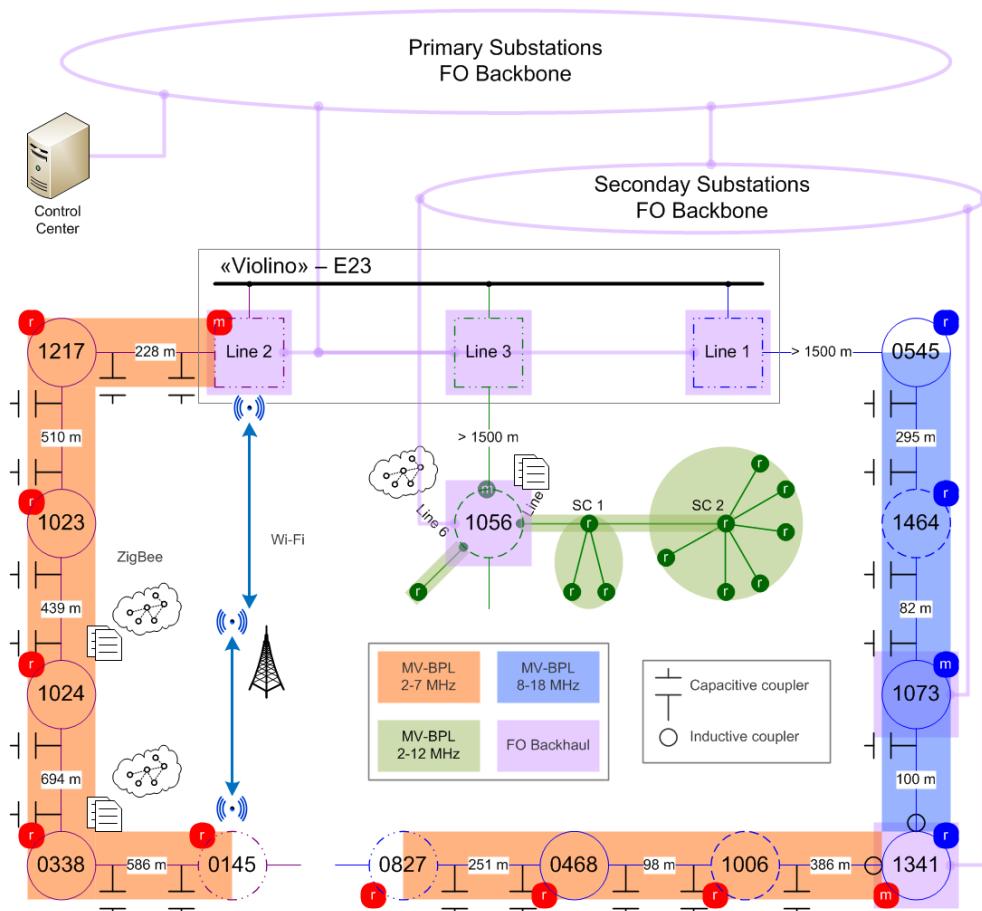


Figure 1.2: INTEGRIS Italian field demonstrators: MV/LV power grid and communication network (simplified scheme).

Measures can be stored in a local database (Figure 1.3), which is just a part of a more comprehensive measurement database. It can be regarded as the natural evolution of present SCADA systems, extending their reach to other sensors and devices (e.g. smart meters). SS is the place of choice where combining data from the metering system and from the MV/LV grid. PSs are, on the other hand, the ideal place to store

HV/MV measurement. The control center is the place where the monitoring of the overall status of the grid takes place.

Data are processed as close as possible to where they are stored. For instance, it is more efficient to perform algorithms – e.g. state estimation, load flow, losses calculation, etc. – relevant to each piece of LV grid in secondary substations than perform them once on the whole MV/LV grid at the control center level. In this way, only aggregated values (e.g. average, min, max, std, etc.) and alarms are brought back up to higher levels of the grid. In fact, higher levels do not need to know every detail of small scale resources located below, at least in real-time. If more detailed information is required to perform some specific algorithms, they simply have to query the distributed database to retrieve the required subset of data. This hierarchical structure can be enhanced introducing a further decision making/storage level directly at the edge of customer premises. Distributed – storage and applications – warrant a higher level of redundancy and limit the traffic across the communication network.

Regarding the standardization process, INTEGRIS proposes to extend the use of IEC 61850 [10] beyond the primary substation automation, using this protocol for all the communication concerning the electrical domain. More in detail, this means:

- to map each point of measure with an IEC 61850 logical node, including customer metering and distributed generation,
- to store each measure into a 61850 database, containing the topological model of the grid.

The only exception is for the direct communication with smart meters which will be based on DLMS/COSEM, the reference standard for metering application. To deal with the logical node mapping of DLMS/COSEM resources, a 61850-DLMS/COSEM protocol convention stage is necessary in secondary substation, where the aggregation of electrical equipment data and customer data takes place.

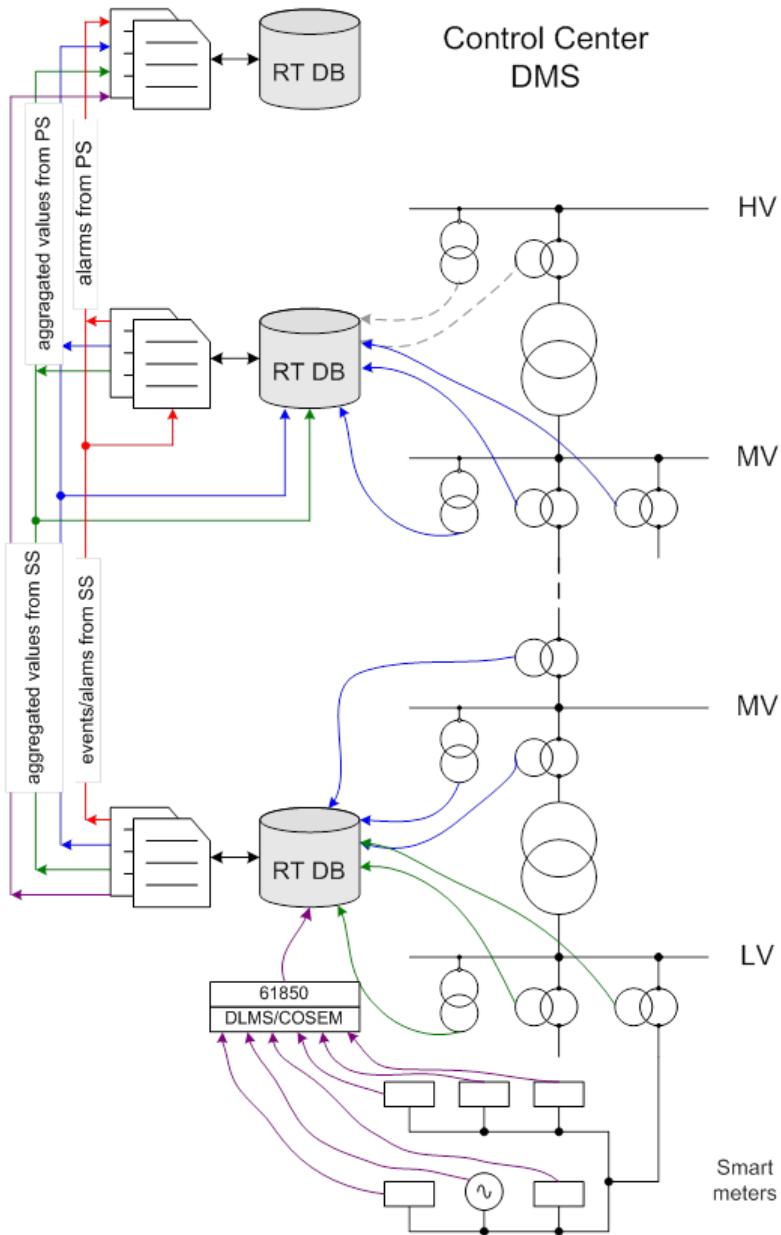


Figure 1.3: Reference scheme of the integrated monitoring use case as defined by INTEGRIS.

### 1.3.4 SDG – Smart Domo Grid [50]

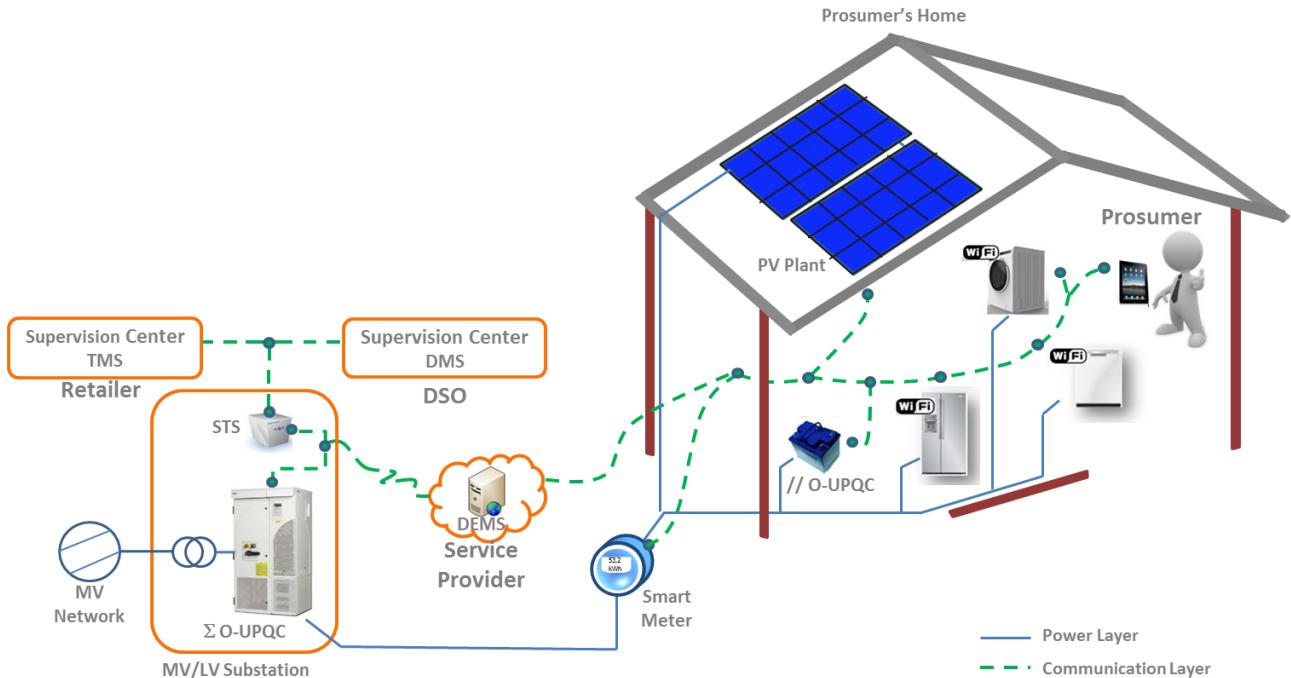
SmartDomoGrid (SDG) [50] is a project co-funded by the Italian Ministry of Economic Development (*Ministero dello Sviluppo Economico*). It deals with the test in a real operational environment of two main topics:

- Demand Response programs aimed at shaving peak power demands and slow voltage variations (congestions) in order to reduce investments for new network infrastructures,
- the PQ improvement on the LV grid by means of a power electronics equipment.

To join the DR program, the customer has to install some loads devices such as Smart Appliances (SA) and sign a contract with a Service Provider which makes available a Domestic Energy Management System (DEMS). The DEMS, one for each customer, is able to find the best schedule for SAs according to some

boundary conditions set by the customer via a Graphical User Interface. The power quality deals with a device called O-UPQC (Open Unified Power Quality Conditioner), which consists of:

- a series electronic device installed in the MV/LV substation,
- several shunts units installed at the customer's home, connected to Domestic Distributed Energy Storage (DDES), and able to isolate the customer from the grid in case of sever PQ issues (islanded operation).



**Figure 1.4: Main elements involved in the SDG project (simplified scheme).**

This project runs on the same area of the INTEGRIS project. For the sake of the test, the entire LV grid of a secondary substation was included (8 LV feeders) and about 40 customers – many of them with a domestic PV – were monitored by using smart meters. 21 customers received smart appliances and 5 of them installed the O-UPQC shunt unit. Data from smart meters are collected by using LV-BPL up to the secondary substation database. According to the INTEGRIS' principle, data are locally processed to determine the presence of congestions. If any congestion is detected, the system tries to involve controllable elements by:

- directly controlling the O-UPQC series unit to increase/decrease the voltage average level on the secondary side of the MV/LV transformer,
- involving those customers who have a DEMS. The DEMS – after receiving a request – e.g. reduce the consumption; sink/inject reactive power on the network; controls smart appliances and the O-UPQC shunt unit.

### 1.3.5 INCREASE – INCreasing the penetration of Renewable Energy sources in the distribution grid by developing control strategies and using Ancillary Services [5]

The basic idea of the INCREASE project [5] consists in exploiting grid connected resources, equipped with power electronic interfaces enabling flexible actuation, to provide also grid support. The control strategy of such numerous devices is to be implemented in a local way, in particular in an agent framework, and should yield an optimized operation. This way these resources can provide ancillary services to the DSO, and to the

TSO, focused in particular on voltage control and provision of reserve. An incentive to participate to the grid support should then come from the newly created market of ancillary services. The resources would participate into this market through an Aggregator. Similarly, in IDE4L distributed resources are expected to support the grid and the Aggregator is expected to provide technical services. However, IDE4L does not investigate in particular the implementation of the distributed control in the agent framework, which would set additional requirements on the architecture. It is nonetheless reasonable to assume that the IDE4L architecture can support this framework as well, as it is designed to support distributed applications such as decentralized FLISR and voltage control. As INCREASE is part of the collaboration with other European projects from the ENERGY 2013 7.1.1 Call [1] and it is developing time wise in parallel to IDE4L, it is difficult to incorporate its findings. Nonetheless, the participation of an IDE4L representative in the Advisory Board of INCREASE facilitates the exchange of information.

### **1.3.6 EvolvDSO – Development of methodologies and tools for new and evolving DSO roles for efficient DRES integration in distribution networks [6]**

EvolvDSO project [6] aims at defining the future roles of DSOs and developing tools required for these new roles on the basis of scenarios which will be driven by different DRES penetration levels, various degrees of technological progress, and differing customer acceptance patterns.

EvolvDSO's targeted outcomes are the followings:

- Future scenarios and new DSO roles – A limited set of possible future scenarios describing the evolution of electricity systems including the anticipation of future challenges of distribution systems and required new/evolving DSO roles;
- Development of validated tools and methods – Set of validated tools and methods with a high replicability potential focused on where the main gaps are with respect to the identified DSO challenges and new required DSO roles. These tools should address both current and possible future challenges of the distribution system;
- Evaluation of tools performance – Methodologies to evaluate the performance of the developed tools and methods considering the requirements of the key stakeholders (aligned with the EEGI requirements);
- Recommendations – Recommendations for the modification of the regulatory framework and market architectures (new roles, responsibilities and interactions in the system) that take into account current technical requirements with the aim to facilitate an efficient DRES integration and more active consumers as well as market participation of new stakeholders such as aggregators and BRPs; the increasing need for storage similarly needs to be accommodated by the regulatory framework;
- Roadmap – A pragmatic roadmap for the deployment of the developed tools and methods.

As EvolvDSO is part of the collaboration with other European projects from the ENERGY 2013 7.1.1 Call [1], it will mainly share with IDE4L project developed scenarios, including potential future role of DSO which have been delivered at the present date of writing this deliverable.

### **1.3.7 DREAM – Distributed Renewable resources Exploitation in electric grids through Advanced heterarchical Management [7]**

The DREAM project [7] will lay the foundations for a novel heterarchical management approach of complex electrical power grids, providing new mechanisms for stable and cost effective integration of distributed renewable energy sources, as well as for enhanced consumer involvement in economic and ecological

electricity use. Applying the principles of autonomous agent-based systems to the control and management of the electricity distribution grid will allow the system to constantly adjust to current operational conditions and make it robust to exogenous disturbances.

In turn, this will allow for greater penetration of intermittent resources and will make the distribution grid more resilient to failures. DREAM will include several layers of controls for normal, congested and post-contingency situations that will use different coordination strategies ranging from market based transactions to emergency demand response and create ad-hoc federations of agents that will flexibly adjust their hierarchy to current needs.

The system will transition smoothly between control layers depending on local operational conditions, so that responses to disturbances will be sized precisely, margins will be used parsimoniously and full network flexibility will be tapped. The system will involve only limited data transfers and no centralized control, promoting extensibility, heterogeneity and easy deployment across countries with different network architectures and hardware manufacturers.

As DREAM is part of the collaboration with other European projects from the ENERGY 2013 7.1.1 Call [1] and it is developing time wise in parallel to IDE4L, there is a similarity with IDE4L in the used approach and tools for the modeling and design of the heterarchical management architecture.

### **1.3.8 DISCERN – DIStributed intelligence for Cost-Effective and Reliable solutioNs [8]**

The aim of the DISCERN project [8] is to utilize the experience of major European DSOs with innovative technological solutions for a more efficient monitoring and control of distribution networks. In order to do so, DSOs need to change the way distribution grids are operated and maintained to provide a high quality service to their consumers in a reliable high quality power supply at a reasonable cost.

The implementation of the ‘smart grid’ is at the core of the challenge. While the technical solutions are principally available to increase the intelligence of MV/LV grids, the complex task DSOs have to solve is the determination of the suitable level of intelligence and how this can be economically viable, ensuring higher standards of security and reliability.

The main objective of DISCERN is the enhancement of European distribution grids with technical and organizational solutions for the optimal level of smart grid intelligence.

DISCERN will provide DSOs with a better understanding of best-practice system solutions for monitoring and control. Based on the recommendation from DISCERN, DSOs will be enabled to implement solutions that have been tested and validated in various countries and circumstances.

DISCERN will provide insights into the optimal level (amount) of observability on the LV/MV network.

The project will aim at giving DSOs the tools to answer complex questions like:

- How much intelligence do I need in my distribution network to ensure a cost effective and reliable operation of the network?
- What is the most cost-effective solution to implement this intelligence in the network?
- How should the ICT-infrastructure be designed to serve the requirements of a DSO?

### 1.3.9 OpenNode [9]

In the OpenNode project [9], work will especially focus on inner parts of the distribution grid to address the described three major challenges, namely on the research and development of: (1) an open secondary substation node (SSN) which is seen as an essential control component of the future smart distribution grid, (2) a Middleware to couple the SSN with the Utilities systems for grid and utility operation and (3) a modular communication architecture based on standardized communication protocols to grant the flexibility required by the stakeholder diversification and to cope with massively distributed embedded systems in the distribution grid.

### 1.3.10 SuSTAINABLE – Smart distribution System operaTion for mAximizing the INtegration of renewABLE generation [10]

FP7 SuSTAINABLE project [10] develops an integrated approach of future distribution systems considering issues related to power quality, protections, and flexibility management through the scopes of operation, planning, and regulation. In particular, the project targets four main contributions to address the problems raised by massive DG integration: Design and demonstrate the SuSTAINABLE concept, new operation practices of real-time supervision and management of distribution systems.

### 1.3.11 Smart Grid Gotland [11]

One of the smartest electricity network in the world is currently under development on the island of Gotland in Sweden [11]. By using modern technology, large quantities of renewable energy sources can be integrated in the grid. This is being done with improved cost efficiency and preserved quality compared to conventional grid technology National Swedish R&D project where VTF is taking part focusing on Smart Substation, Smart Rural Grid, dynamic tariff structures, market trials.

### 1.3.12 Some reference about the current automation systems of the DSOs

#### *Unión Fenosa Distribución*

Unión Fenosa Distribución (UFD) is a medium-sized DSO which counts a MV network with 487 primary substations, and operates 60.532 secondary substations (38.000 of them owned by UFD, and being the others private). The current MV distribution grid has normally a structured topology. The distribution grid can be arranged in meshed or radial schemes, but its exploitation is always radial. Normally, control and operation in HV level is fully telecontrolled. HV/MV substations are remotely controlled from the SCADA by optic fiber communications, and some of them are prepared for remote management. However, there is normally little control of MV and LV networks. The current network architecture requirements define the installation of telecontrol at some strategic points in the network:

- Feeder circuit breakers in HV/MV substations
- Support points that provide alternative feeding
- Some branch lines that feed clusters of MV/LV substations in rural areas
- Some MV/LV substations in an intermediate point of active cables in urban areas<sup>1</sup>

So far, it is not feasible to install remote controlled switches in all MV/LV substations. The criteria to install telecontrol in distribution substations have been determined according to technical and economic factors, based on quality of supply and a cost-benefit analysis. These criteria depend on the network architecture and the market it serves:

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<sup>1</sup>We (UFD) distinguish between “active cables” (the ones aimed to supply people), and “zero cable” (from an isolated neutral network).

- In urban networks, remote controlled switches have been installed in rescue centers, which are switching centers that link several active lines, and in some substations located an intermediate point of active lines.
- In rural networks, with sparse consumption, the unit power per substation is significantly lower than in urban areas, and there is no need for a meshed network to ensure a high quality of supply. In this case of tree-shaped radial rural networks there is one remote controlled switch for a certain number of substations that are fed through the same line in a radial basis.

The number of telecontrolled substations in the network is 1.776. Hence, the ratio between secondary substations and telecontrolled substations is 3%. More than the 75% of the total installed power (15800 MVA) comes from secondary substations that complies the requirements to be supported by other feeders in case of need.

Regarding smart metering, as there is an obligation in Spain to substitute all the meters with smart ones by 2018, Unión Fenosa Distribución has started its own deployment plan. Currently, there are 1.154.440 deployed smart meters, and almost all of them are remotely controlled.

In the secondary substation, compound equipment is being installed: the Modular Substation Manager (MSM). Currently, there are 7.439 MSMS installed. They consist of several systems: data concentrator, LV supervisor, and communication system.

Data concentration is necessary in order to gather the data generated in smart meters located at customer premises, and make this information available for other applications. Different types of concentrators are used:

- Conventional Meter Data Concentrators located at secondary substations communicating with smart meters via PLC are used in the general case.
- Virtual Meter Data Concentrators in a central location using mobile networks to communicate with smart meters are used to collect data from scattered smart meters or when conventional PLC communications with smart meters don't work properly.

The LV supervision aims at monitoring power quality of the LV distribution grid, in order to gather information for further actions to maintain currents, voltages and Power Quality indexes within permissible levels. LV supervisors are Intelligent Electronic Devices (IEDs) that collect voltage and current measures from sensors in the LV side of secondary substations, perform registrations of energy, measures and events, and generate alarms when some voltages or currents are out of margins.

### ***Oestkraft***

Oestkraft (OST) is a small size DSO situated on Bornhol Island, Denmark. Peak load on the grid is 55 MW. Under normal conditions the grid is connected to the Swedish grid via a 60 kV (70 MW) subsea cable. However, there is enough generating capacity for islanding operation based on the following equipment:

- 1 steam turbine (wood/coal/oil/chips): 37 MW
- 35 wind turbines: 30 MW
- Solar PV: 6 MW
- 2 gas engines (biogas): 2 MW
- 14 back-up generators (diesel): 34 MW
- 1 back-up steam turbine (oil): 25 MW

The grid consists of 16 primary substations (60/10 kV) and 1039 secondary substations (10/ 0.4 kV), all of them owned by OST. Total number of customers is 28.000. App. 2000 customers have smart meters with the possibility to log the measurements with 5 minutes resolution.

Total length of the grid: 60 kV = 131 km and 10 kV = 927 km.

The primary substations are connected to the SCADA system in the central control room via optic fiber network. All primary substations can be remotely controlled.

All secondary substations are manually operated without any remote control. In order to demonstrate the UC “Decentralized Solution for Fault Detection, Isolation and Location”, two secondary substations will be equipped with remote controlled 10 kV Circuit Breakers.

### **A2A Reti Elettriche (ARL)**

A2A Reti Elettriche SpA (A2A) is the electricity distribution subsidiary of the A2A Group, multi-utility operating mainly in the north of Italy in the energy sector (electricity, gas, water management, district heating, waste management, etc.). It distributes over 11 TWh of energy per annum and, with over 1.1 million customers served, it is the second DSO in Italy. The distribution network of ARL is made up by the two isolated areas: the grid of Milan and grid of Brescia, including the city and the west side of Lake Garda. As a whole, ARL’s grid is spread across both highly dense urban areas as well as extra-urban, lacustrine and mountainous environments – which therefore present diverse characteristics and issues. It includes about 40 HV/MV transformer substations (PS) and over 8500 MV/LV transformer substations (SS). Typical voltages levels managed by ARL are 23 kV and 15 kV for the medium voltage, 400 V three-phase for LV backbone feeders and 230 V for low voltage lines connecting single-phase customers. MV and LV cables in rural areas are mainly overhead. The MV network is a mesh network normally operated in radially. The LV grid is mainly radial.

Hereafter are illustrated the technologies used to manage the electric grid of ARL. Those technologies are not consistently deployed all over the Brescia and Milan network, thus this portrait describes an “average” condition of ARL network status.

Each area has its own supervisory system (SCADA) used to control primary substations and roughly the 20% of secondary substations. It continuously receives feeds on network states and alarms via remote terminal units (RTUs). RTUs allow the sending of remote command e.g. to disconnectors or circuit breaker that alter the topology of the MV grid when is needed or to transformers with on-line tap changers in case a voltage regulation is needed. In the near future the control of the overall network will be delegated to a new Distribution Management System (DMS) integrating also a SCADA which will become the unique supervisor installed in two interoperable control centers.

PSs have been already equipped with Substation Automation Systems (SAS), based nevertheless on proprietary standards from different vendors. New PS already was born according to the IEC 61850 standards. A SAS consists of:

- sensors which collect the main electrical quantities (voltage, current, powers, etc.);
- intelligent electric devices (IEDs), implementing some relevant protection function such us the 67N (ground directional instantaneous overcurrent protection) and 50P (phase instantaneous overcurrent protection);

- breakers which are used to protect assets in primary substation in case a fault occurs, typically opening the main circuit breaker of the MV line.

Measures collected by the SAS are then reported to the SCADA system to provide to control center operators an overview of the power flowing on the network.

In recent years, along with SCADA and SAS, ARL has launched an effort to make the MV/LV grid network management more pervasive. The energy distribution peaks in summer time, due to the high presence of air cooling appliances, has induced ARL to introduce a MV/LV monitoring system (SMS) which now covers about 50% of the SSs and it is still in deployment phase. Likewise, in all PSs ARL has already installed Power Quality analysis tools (PQS) on MV busbars in order to be ready for the new target set by the Authority.

The selection for the distribution of these controllable and monitorable SSs has been done keeping in consideration a set of cost/benefit indexes and searching the optimum between costs for telecommunication infrastructures and controllable devices and controllability of the network. By doing so, only the most strategic SSs (i.e. those ones located in a three points of supply or those ones used to switch from a radial configuration to another) have been equipped. In future most of the SSs will be controlled and monitored in order to improve quality of service reducing costs for interruptions and reconfigurations. The same approach will be applied to bring the today PSs protection systems in the MV substations too, involving also LV grid with dedicated breakers and monitoring systems.

Lastly, ARL has now completed the deployment of electronic meters at the edge of customers' homes and low voltage concentrators (LVC) in SS, and its own Automatic Meter Management system (AMM). However, AMM provides commercial functionalities only (user connection/disconnection, power curtailment, billing, etc.). And it is not used to manage the grid.

Compared to other European DSOs, ARL's network management state of the art is characterized by a fairly good level of technology penetration. That notwithstanding, the deployment of substation systems has taken place in the 90's and early 2000, when the role of ICT was still less relevant. Therefore the technology introduction was characterized by a proliferation of centralized and vertical subsystems, often not interoperable and hardly underpinned by a coherent communication architectural design. For this reason, ARL is now in the process of redesign the entire communication network for the management of the distribution grid (both MV and LV).

## 2. Description of Working Approach

In response to the EU Mandate M/490 [12], two crucial results were obtained in terms of tools for supporting the standardization in the field of Smart Grid: the Smart Architecture Model (SGAM) [13] and the Use Case Methodology [14]. In particular, the SGAM was developed to offer a framework for Smart Grid architectures, and the Use Case Methodology provided use case templates as well as a comprehensive methodology for the management of use cases. The tools have encountered utilization in several EU Projects to systematically develop automation architectures in the context of Smart Grid. The focus of this chapter is to demonstrate the usage of the Use Case Methodology and the SGAM framework to formally develop the automation architecture in the IDE4L Project. The proposed process, however, slightly differ from the state-of-the-art usage of those tools. In fact, it is based on an incremental approach which leverages on two other FP7 European projects about automation architecture, i.e. INTEGRIS [4] and ADDRESS [3], as a starting point upon which the IDE4L automation architecture will be systematically expanded to fulfill the identified requirements in deliverable D2.1 [1].

### 2.1 Conceptual Steps in the Development of the IDE4L Automation Architecture

This section gives the conceptual steps under which the IDE4L architecture development is going through within the whole WP3 as shown in Figure 2.1 and Figure 2.2:

1. **Concept (Task 3.1):** The concept of the architecture is derived from the high-level description of use cases. This concept defines functionalities and modes of operation that the architecture must enable (what the architecture is able to do, what it takes in principle to realize it, in terms of infrastructure, information, communication, and functions). The automation concept is built up based on use case descriptions coming from the applicative WPs 4-6 and from the demo WP7 as well as from experience of other EU Projects (e.g. INTEGRIS, ADDRESS).
  - Deliverable D3.1 - Distribution automation concept (this deliverable): Concept of distribution automation for project development phase. Integration of aggregator to DSO IT systems and extension of market based DR to be used by DSO will set a new framework for active network management. (month 12)
2. **Draft (Task 3.2):** From the general description of the use cases, the draft architecture and the testing features are derived (implementation and integration, and numerical simulations). Identification of challenges in semantics, allocation of functions, integration (to derive design specifications from the concept) is formulated in this stage allowing, though, an incomplete mapping of use cases on to the SGAM framework.
  - Deliverable D3.2 - Architecture design and implementation: Design and implementation of distribution automation in details for project demonstration phase. Contribution to standardization activities, specification of distribution automation equipment in MV and LV networks using IEC61850, specification of distribution PMU's, and methods for exploiting PLC signals in distribution grids. (month 24)
3. **Detailed (Task 3.2 & Task 3.3):** From the detailed description of the use cases (including data models, standards, protocols etc.) the complete, detailed architecture is derived, together with the full testing features of the demonstrations. ICT requirements are consolidated by mapping the use cases on to all layers of the SGAM framework.
  - Deliverable D3.3 - Laboratory test report: Results of laboratory tests of distribution automation system and applications. RTDS simulation environment for general purpose smart distribution grid testing. (month 33)

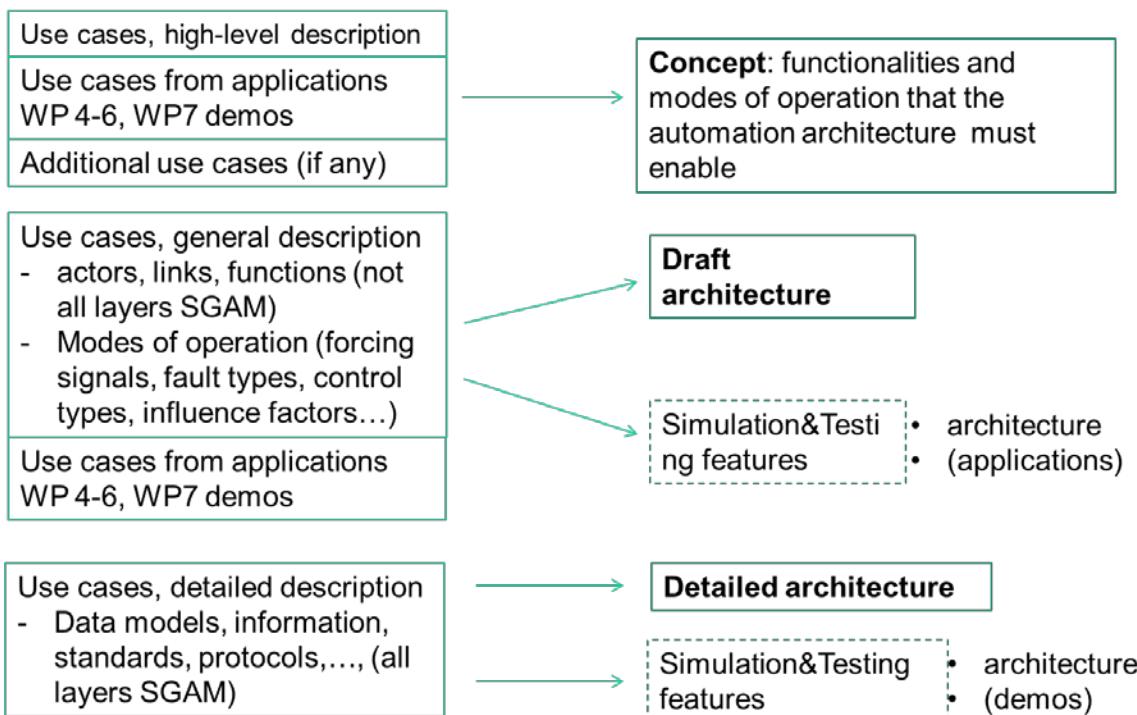


Figure 2.1: Conceptual steps in the development of the architecture.

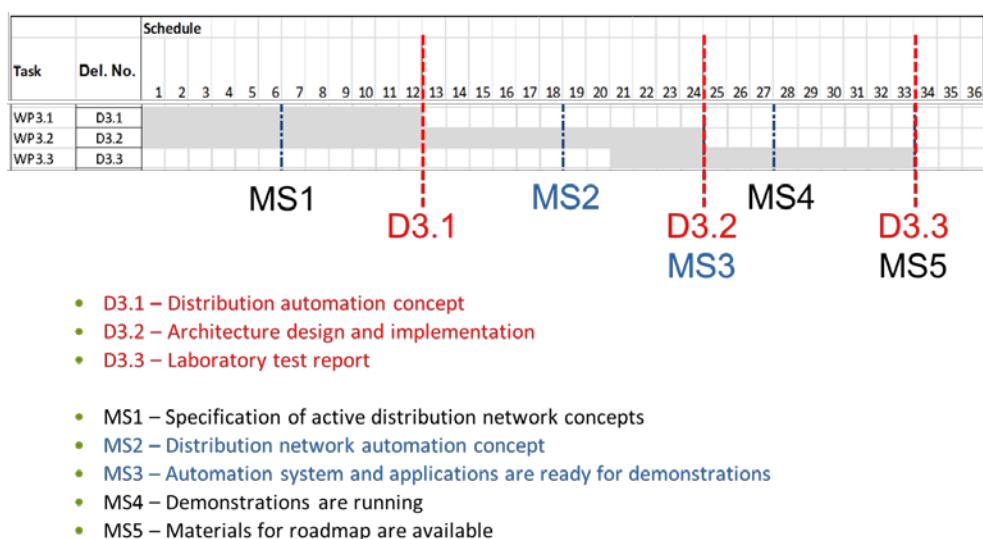


Figure 2.2: Time line in WP3 with tasks, deliverables and milestones.

## 2.2 Background

The automation architecture of the IDE4L Project is a complex system, involving an extensive variety of stakeholders with many domains of expertise. To address this feature, the “Use Case Methodology”, originally proposed in [14] for supporting standardization bodies in identifying existing gaps, is adopted in the IDE4L Project to systematically derive requirements for the architecture. This methodology is based on use case descriptions in a standardized template (the IEC Publicly Available (PAS) 62559 [15]) and the mapping of these use cases onto the layers of the SGAM framework [13].

## 2.2.1 Important Definitions

In this subsection some important definitions are given in order to support the rest of the chapter. These definitions, unless specifically stated, are taken from [14].

**Architecture** – Fundamental concepts or properties of a system in its environment embodied in its elements, relationships, and in the principles of its design and evolution [16].

**System** – A typical industry arrangement of components, based on a single architecture, serving a specific set of use cases.

**Interoperability** – The ability of two or more devices from the same vendor, or different vendors, to exchange information and use that information for correct co-operation [17].

**Demand Response (DR)** – A concept describing an incentivizing of customers by costs, ecological information or others in order to initiate a change in their consumption or feed-in pattern (“bottom-up approach” = Customers decide).

**Demand Side Management (DSM)** – Measures taken by market roles (e.g. utilities, aggregator) controlling electricity demand as measure for operating the grid (“top-down approach”).

**Market** – An open platform operated by a market operator trading energy and power on requests of market participants placing orders and offers, where accepted offers are decided in a clearing process, usually by the market operator.

**Microgrid** – A low-voltage and/or medium-voltage grid equipped with additional installations aggregating and managing largely autonomously its own supply- and demand-side resources, optionally also in case of islanding.

**Use Case** – Class specification of a sequence of actions, including variants, that a system (or other entity) can perform, interacting with actors of the system [15][18].

**Use Case Cluster** – A group of use cases with a similar background or belonging to one system or one conceptual description.

**High Level Use Case** – A use case which describes a general requirement, idea or concept independently from a specific technical realization like an architectural solution.

**Primary Use Case** – A use case which describes in detail the functionality of (a part of) a business process.

**Secondary Use Case** – An elementary use case which may be used by several other primary use cases.

**Specialized Use Case** – A use case which is using specific technological solutions / implementations.

**Generic Use Case** – A use case which is broadly accepted for standardization, usually collecting and harmonizing different real use cases without being based on a project or technological specific solution.

**Use Case Template** – A form which allows the structured description of a use case in predefined fields.

**Scenario** – A possible sequence of interactions.

**Activity Steps or Step-by-Step Analysis** – The elementary steps within a scenario representing the most granular description level of interactions in the use case.

**Actor** – An entity that communicates and interacts. These actors can include people, software applications, systems, databases, and even the power system itself.

**Role** – A role played by an actor in interaction with the system under discussion.

### 2.2.2 The Use Case Methodology

Originally proposed in the field of Software Engineering, Use Cases describe the requirements, general and specific functionalities, and applications that a system should support. Moreover, they represent a common way of understanding for domain and IT experts in charge of implementing these functions. The concept of use case has been adopted in the field of smart grids, for which the standard IEC/PAS 62559 [15] is currently under development.

Within the IDE4L Project and especially in WP3, use cases are needed to define the automation architecture, along with its actors, functions, components, interfaces, data models and data objects as well as the standards and protocols to support the interoperability concept. More in detail, use cases are used to describe the automation architecture requirements and functionalities, and should support a common understanding of experts from different sectors, like electrical engineering and IT experts. Therefore, a shared methodology and tools are required.

In the context of Smart Grids, a use case template is proposed which poses the basis for the use case description as a common structure of documentation to maintain consistency. The template, proposed in three versions, i.e. *short*, *general* and *detailed*, is shown in Figure 2.3. The common fields in the three templates are identical as the general and the detailed versions are just adding more information fields, so that it would be possible to start the use case description procedure with the short template and move on with the general one and complete the description with the detailed one. Thus, the structure of the template enables an incremental use case description in line with the conceptual three-step approach described in section 2.1. For instance, domain experts may first contribute with the short and general use case templates, and then ICT expert may take care of the detailed template, finally leading to technical specifications and requirements for the implementation.

The meta model of the use case template is shown in Figure 2.4. This diagram highlights the logical interlinks among single fields and/or parts in the template. In this context, a *Use Case* describes the expected goals that an *Actor* has to achieve within a particular *System*. To achieve these goals, other *Actors*, like for instance Systems, humans, Applications or Components, can be involved, which act in a particular *Role* depending on the use case. According to IEC/PAS 62559, use cases can consist of several *Scenarios* which can for instance describe the execution of the use case in normal, error or maintenance scenarios. *Scenarios* consist of several *Activities*, defined by the information exchange between actors including defined *Information Objects*. Each activity can moreover identify *Technical Requirements*, e.g. quality of service or security. With the detailed version of the template, use cases can additionally specify *Standards* to be applied for the realization of the use case. Use cases can also be classified to several criteria as for example the location in the Smart Grid Architectural Model SGAM (Domains and Zones—see Section 2.2.4).

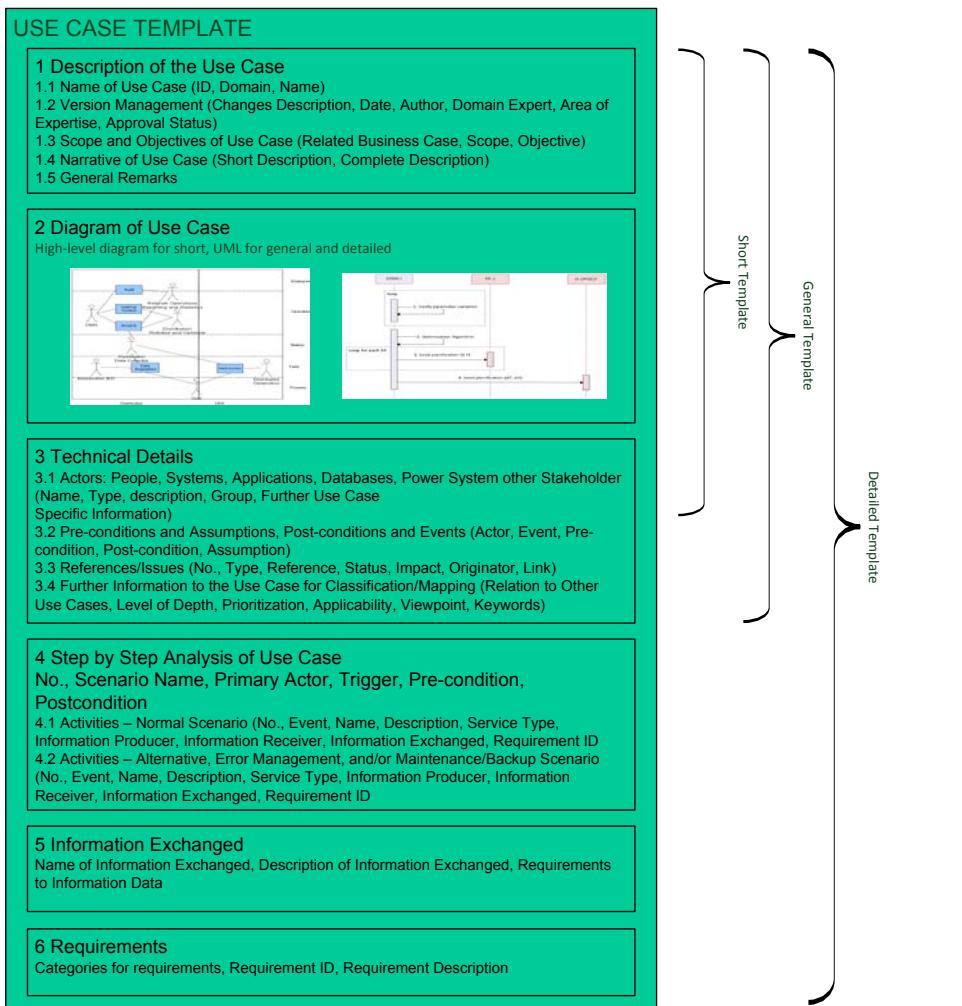


Figure 2.3: Overview of IEC 62559 Use Case Template.

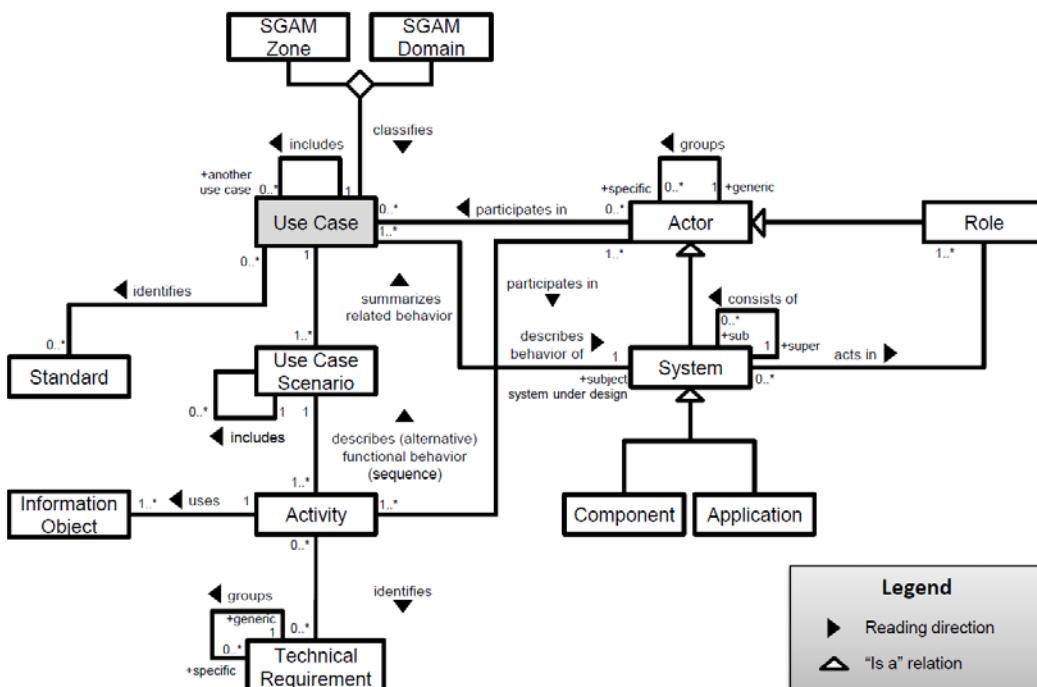


Figure 2.4: Use case template meta model [15].

The Use Case Methodology was originally proposed for standardization bodies in the context of Smart Grids in response of the EU Mandate M/490. To better understand the proposed process adopted in the IDE4L Project, the following paragraph explains the original management process for Smart Grid use cases. The process is depicted in Figure 2.5 and goes through three steps: Ideas/Requirements, Elaboration, and Standards Development. In parallel, the Level of Detail/Realization increases along the three steps.

Within the Ideas/Requirements step, project proposals for standardization are elaborated through a work that usually comprises short descriptions of the project and corresponding high-level use cases. The developed use cases descriptions are based on the IEC/PAS 62559-based template and stored within the central repository. New use cases are developed in two phases: 1) initial functional descriptions provided by domain experts, and 2) more details provided by technical experts. Existing use cases are, instead, consolidated and harmonized by standardization experts conceptually and under the functional standpoint beforehand.

In the Elaboration step a more detailed and precise description of the generic use cases as well as the identification of links to other use cases is provided. Other information described in a generic use case, such as communication standards and protocols, information objects and actors (e.g., systems, software applications or other components), shall provide input to a reference architecture. Such a reference architecture, i.e. the interoperability layers of the Smart Grid Architecture Model (SGAM) (subsection 2.2.4), can guide the implementation and also serve as a reference ontology for further use case creation. At this point, the analysis of use cases to realize the use case's requirements (e.g. IT security) can take place.

In the final Standards Development step, standards are analyzed regarding their applicability for implementation of the functions described within the use cases. Gaps regarding standardization can be identified by mapping use cases on the SGAM. This mapping does not only enable a gap analysis but also the analysis of the coverage of existing standards. As use cases serve for the definition of standards, they can also be used as an interoperability test. By doing so, new requirements may arise. The consequent results can be fed in the definition of new use cases and also the refinement of existing ones. This means that the whole process may have to be executed again (retrofitting arrow).

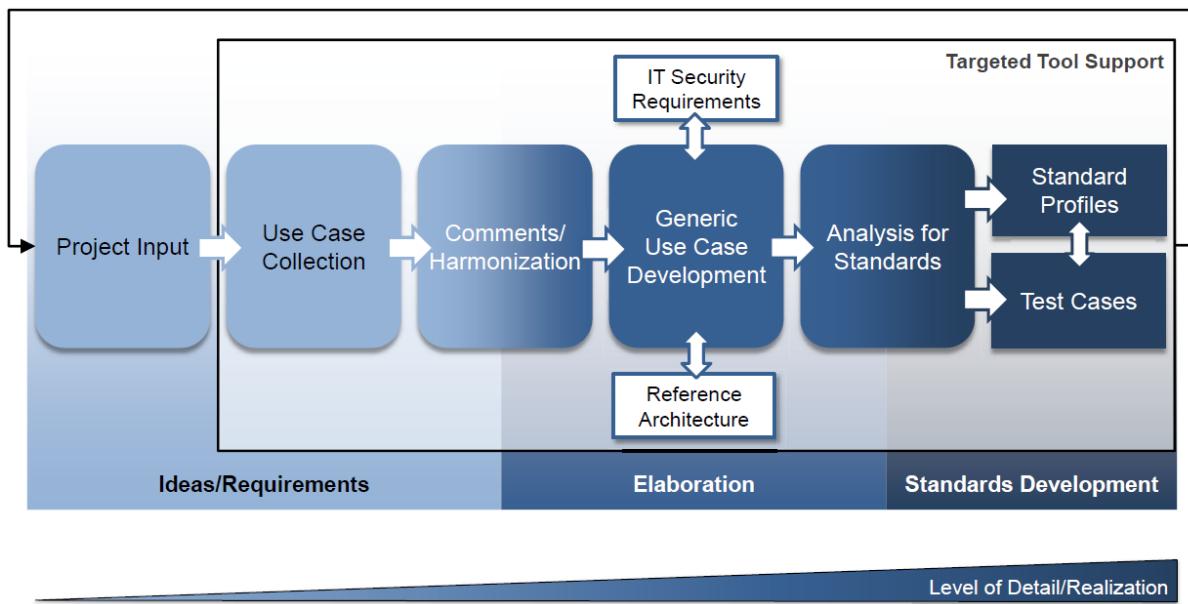


Figure 2.5: Use case management process for the development of Smart Grid Standards [19].

This approach, as mentioned above, was originally adopted for standardization bodies in response to the EU Mandate M/490 [12], and has a different goal within the IDE4L Project. The goal of the Use Case Methodology here is to define, develop and realize the automation architecture able to support all the functionalities described in deliverable D2.1 [1]. Use cases served as the basis for the description of the IDE4L automation architecture functionalities are stored in a central repository, called Use Case Management Repository [20] (Figure 2.6).

The screenshot shows the UCMR (Use Case Management Repository) interface. The left sidebar contains a navigation menu with categories like Area: RWTH, UC for Discussion, Actors, Requirements, Real Time, Forecasting, System Updating, Specialized UCs, and various sub-areas. The main content area displays a use case entry for "Medium Voltage Network Real Time Monitoring (MVRTM)". The entry includes fields for Name of Use Case (Medium Voltage Network Real Time Monitoring (MVRTM)), UseCase ID (131), Domain(s)/Zone(s) (No Domain or Zone assigned), and a short description. The description notes that data is stored in a unique repository located in the Primary Substation after managing implementation issues. It also defines "Real-time" as something between 1 second and some minutes. The complete description section lists data considered by the use case, such as Mean values of V, I, Q, P, MV lines, MV side of transformers and MV lines in secondary substations (RTU, IED), PQ indexes from primary substations and some relevant secondary substations (PQM), status of remote-controllable elements in primary substations and in secondary substations (RTU-IED), breaker/disconnectors, tap changes of HV/MV transformers, voltage or reactive power set-points for generators connected on the MV network, and alarms related to events and faults (IED-PQM-RTU). Measures, events, and states provided by the Distribution Management System (DMS) are also mentioned. The right sidebar lists actors: Distribution Management System (DMS), Meter Data Concentrator (MDC), Power Quality Meter (PQM), Remote Terminal Unit (RTU), Intelligent Electronic Device (IED), Smart Meter (SM), Data eXchange Platform (DXP), and Primary Substation Automation Unit (PSAU). A search bar and administration links are also visible at the top.

Figure 2.6: Screenshot of the Use Case Management Repository online tool adopted in the IDE4L Project for the use case collection.

### 2.2.3 Use Case Classification

#### Business Use Cases and Application Use cases

There are two types of Use Cases:

- Business Use Cases describe the business processes the Actors of a given system must and may execute.
- Application Use Cases describe the Smart Grid Functions required to enable / facilitate the business processes described in Business Use Cases. Their purpose is to detail the execution of those processes from an Information System perspective.

Since a Smart Grid Function can be used to enable / facilitate more than one business process, an Application Use Case can be linked to more than one Business Use Case. Hereafter, Application Use Cases will be simply called Use Cases, while the Business Use Cases that they are serving is not described in detail at this level of description; however, a first explanation is included in the general description.

### ***Classification of UCs based on granularity and technological abstraction***

It is worth to give a definition of use cases following the instructions in the SGAM workgroup [14] as depicted in Figure 2.7. High level use cases are intended to provide a general description of the functionality and to define actors and functions that cannot be mapped directly in a certain application due to the high level of definition, but rather are applicable as different systems of components, functions, standards. Primary use cases reach a level of definition which allows mapping the use case in a specified architecture. Nevertheless, the architecture at this level is technologically neutral, meaning that different hardware or software components as well as different communication protocols can be used to implement such architecture in real power networks. Secondary use cases are a sub-cluster of Primary use cases and are intended as core functionalities which are shared among several primary use cases. Eventually specialized use cases contain technology specifications on the architecture features. Figure 2.7 represents the hierarchical organization of Use cases based on granularity and technological abstraction.

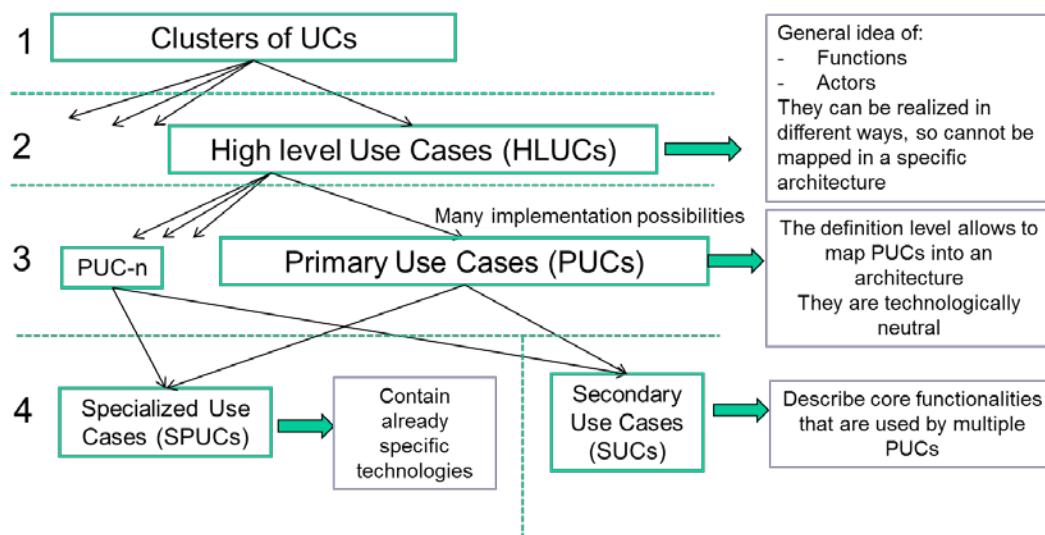


Figure 2.7: Classification of Use cases based on granularity and technological abstraction.

### ***Classification based on business context***

This classification is based, instead, on the applicability of use cases in regional or business context as generic or individual. Generic use cases are broadly accepted in standardization and not project or technology specific. Individual use cases are valid instead in particular regional or business areas. Two approaches are possible: a company might combine generic use cases, developing them further to individual ones; or some individual use cases coming from several companies can be combined for the sake of standardization obtaining a generic use case.

### Content of UCs

The use case represents a particular functionality of the smart grid which is triggered by one or more scenarios in the grid. It will hence take place regularly, on demand or on response of particular contingencies in the grid. Several levels of description are considered: short, general, detailed, bringing deeper level of definition of the use case. The main content is represented by the actors, the functions and the business services. The actors are the first contribute and could represent the hardware and the software to be bought or developed and installed, the persons and the enterprises which have to be juridically recognized and their role. The functions represent the algorithms, or the actions that hardware and software must accomplish and the operation that the people and companies are allowed or intended to perform. The business services define the business goal that the authors are accomplishing and hence aim at describing the economical motivation for the development from the current state of the grid to the one required to perform the functionalities of such use case. Summarizing, the use case permits to obtain the practical information to understand the development and investment needed in the grid relatively to the functionalities required by it.

### 2.2.4 The Smart Grid Architecture Model Framework and Methodology

The Smart Grid Architecture Model (SGAM) framework [13] is a primary importance result of the EU Mandate M/490. The SGAM framework and its methodology allow the graphical representation and analysis of Smart Grid use cases in an architectural technological neutral manner highlighting their interoperability aspects thanks to its five interoperable layers [13]. More specifically, the SGAM framework enables the validation of Smart Grid use cases supported by standards which may not exist at the present date yet. Possible identified gap(s) is (are) disseminated among standardization bodies. In the context of the IDE4L Project, the SGAM framework is used to provide a method to define concepts, to have a system-level viewpoint, and to map collected use cases, thus enabling a systematic approach to develop the automation architecture. As a requirement, the systematic approach has to deal with the complexity of the IDE4L automation architecture and has to allow the representation of the current state of the architecture implementation supported by the principles of universality, consistency, flexibility, and interoperability [13]. Likewise the Use Case Templates, in the SGAM framework the interdisciplinary workforce working on smart grid, like system engineers and IT experts, is supported by a simple and at the same time comprehensive tool. Furthermore, the SGAM framework supports the comparison of different smart grid solutions so that differences and commonalities can be immediately identified. The latest aspect is quite important since the IDE4L automation architecture development is based on the incremental approach mentioned at the beginning of this chapter and better explained in the next section.

For the sake of the understanding of the usage of the SGAM framework within the IDE4L Project, the following of this subsection briefly provides only a short review of the SGAM framework. For extended description of the SGAM the reader is kindly invited to refer to [13].

The SGAM framework is based on the concept of *Smart Grid Plane*, which constitutes the basic viewpoints of the SGAM architecture visualization. These viewpoints can be divided into the physical *domains* of the electrical energy conversion chain and the hierarchical *zones* for the electrical process management. The Smart Grid Plane spans in two dimensions: the complete electrical energy conversion chain in one dimension, i.e. Bulk Generation, Transmission, Distribution, DER and Customers Premises domains, and hierarchical levels of power system management, i.e. Process, Field, Station, Operation, Enterprise and Market. The five interoperable layers, i.e. Component, Communication, Information, Function and

Business, allow to model both business and technical viewpoints and span on a third dimension. Figure 2.8 shows the complete three-dimensional SGAM framework.

The *business layer* of the SGAM framework is used to map regulatory and economic (market) structures and policies, business models, business portfolios (products & services) of involved market parties. Business services and processes can be represented in this layer as well. In this way, this layer supports business executives in decision making related to (new) business models and specific business projects (business case) as well as regulators in defining new market models.

The technical perspectives are modeled in SGAM framework on the lower four layers. The *function layer* describes functions and services including their relationship(s) to business need(s). Functions are represented independently from their physical implementation in systems, applications, and components. The *information layer* describes the information that is being used and exchanged between functions, services and components. It contains information objects and the underlying canonical data models. The *communication layer* is used to describe mechanisms and protocols for the interoperable exchange of information between components, functions or services and related information objects or data models. Finally, the *component layer* shows the physical distribution of all participating components. This includes power system equipment (typically located at process and field levels), protection and tele-control devices, network infrastructure (wired/wireless communication connections, routers, and switches) and any kind of computers. For a specific implementation of a use case the identified functions can be mapped onto components complementing the relationships between all layers.

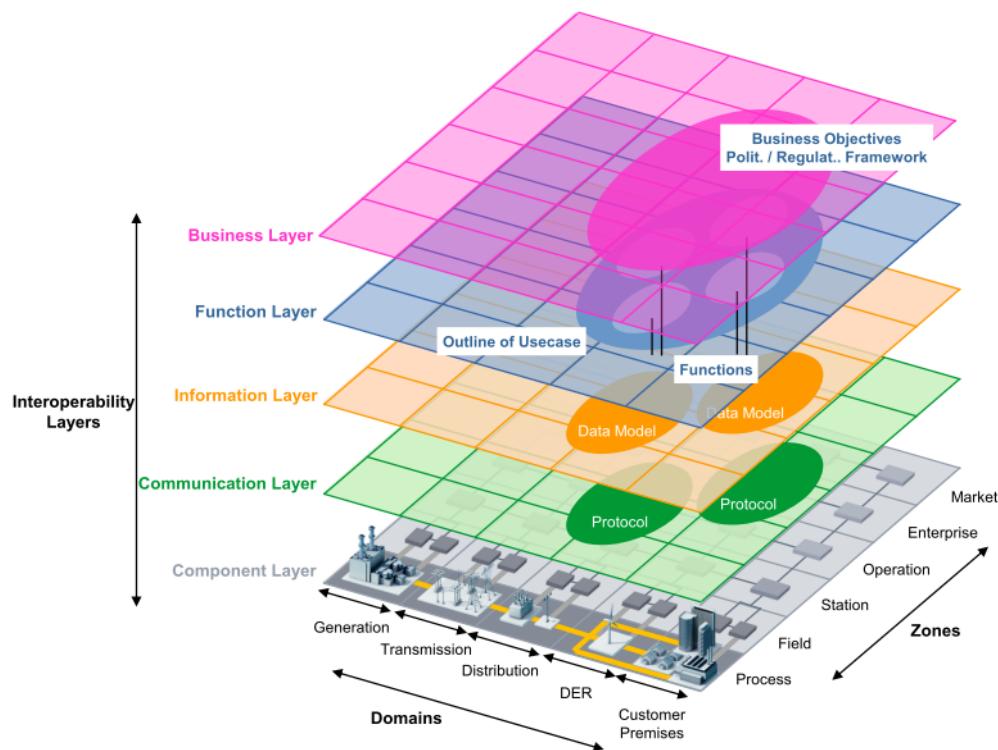


Figure 2.8: Smart Grid Architecture Model (SGAM) framework with its five interoperable layers [13].

Concluding this subsection and emphasizing on the IDE4L Project, a use case analysis can be performed by using the SGAM framework and it is based on the description of the use case in the templates presented in subsection 2.2.2. In fact, the templates provide different information for the analysis, e.g. the field

Domain(s)/Zone(s) specifies directly how the use case is mapped onto the Smart Grid Plane. Furthermore, the actor list used in the use case description provides - depending on the type of the actor - information on the involved roles to model the business layer or information on involved systems and devices to model the component layer. The following types of analysis (which may take place in different times) can be performed within the IDE4L Project:

- Use case categorization: cluster level, high level or primary use cases.
- Synthesis and harmonization of list of actors and functions across different stakeholders (e.g. terminology).
- Functional analysis to extract functionalities, services that the automation architecture should be able to provide. This analysis usually leads to a set of functional requirements.
- Capturing requirements for functions: if the identified requirements can be fulfilled by existing standards or if there is a need for the modification of an existing standards or the need for new standards.
- Testing a use case: which scenarios/sequences (e.g. normal, alternative, faulty operations) can be used for testing purposes.
- Detailed requirements: e.g. quality of service, data management, etc. (refer to the “Requirements” field of the use case templates in Figure 2.3).
- Information for programming, transfer to UML (scenarios/sequences, trigger events, information flow, etc.).
- Linking a use case to a reference architecture and standards.

Figure 2.9 shows an overview of all interoperable layers of the SGAM framework upon which the use case analysis can be performed. The figure is intended to provide guidance on how to model a use case by using the SGAM framework on a chosen level of abstraction starting from a concept up to a detailed level which enables the implementation. What Figure 2.9 suggests is that in order to derive the next level of detail further information is needed from the use case description. In line with this idea, the next section will show the systematic approach for the IDE4L automation architecture development based on the usage of both tools, i.e. the use case templates and the SGAM framework.

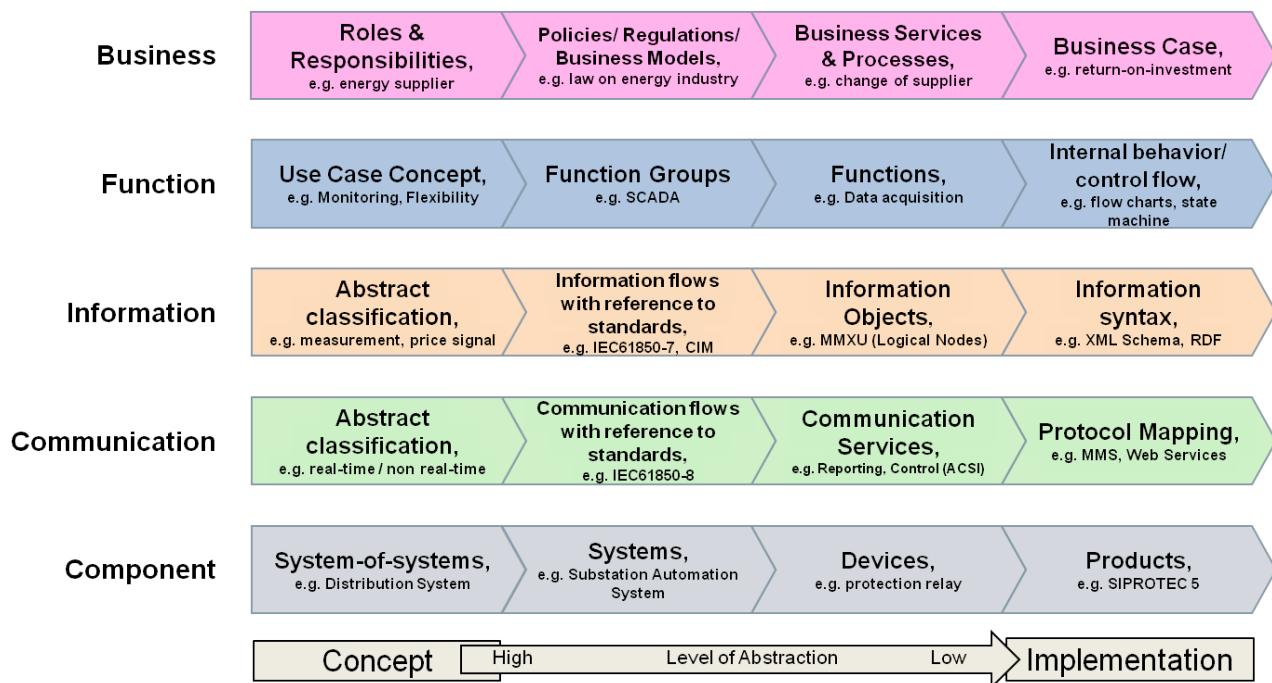


Figure 2.9: Use case analysis pattern based on the SGAM framework [21].

The use case templates fit to the use case analysis pattern based on the SGAM framework as shown in Figure 2.10. The description of a use case in a given template should provide enough information to describe the required level of abstraction in the SGAM layer(s). The short template can be used to document the use case concept. Most of the information is contained in the narrative of the use case and the use case diagram. Actors and functions can be extracted from the narrative. Moreover, the use case can be mapped on the Smart Grid Plane of the SGAM framework in the affected domains and zones. The general and detailed templates may offer both a technical and business orientation of the described use case. Both business-oriented and technical-oriented actors can be described within the use case and the difference between the two types of actors consists in what they represent for use case goal/purpose: business actors play a role in the context of the enterprise scope of the use case; technical actors are usually identifiable as devices and/or systems. As suggested in [21], it is advisable not to mix business use case and technical use case in a single use case description, and the IDE4L Project is adopting the same viewpoint. For instance, the step-by-step analysis of a business use case can be used to define business process(es) to be mapped on the business layer of the SGAM, while the step-by-step analysis of a technical use case provides details on the information exchange and the way it is exchanged to map the communication and the information layers of the SGAM. Notice that the business and technical orientations are somehow mixed in the short template as it does not provide enough details.

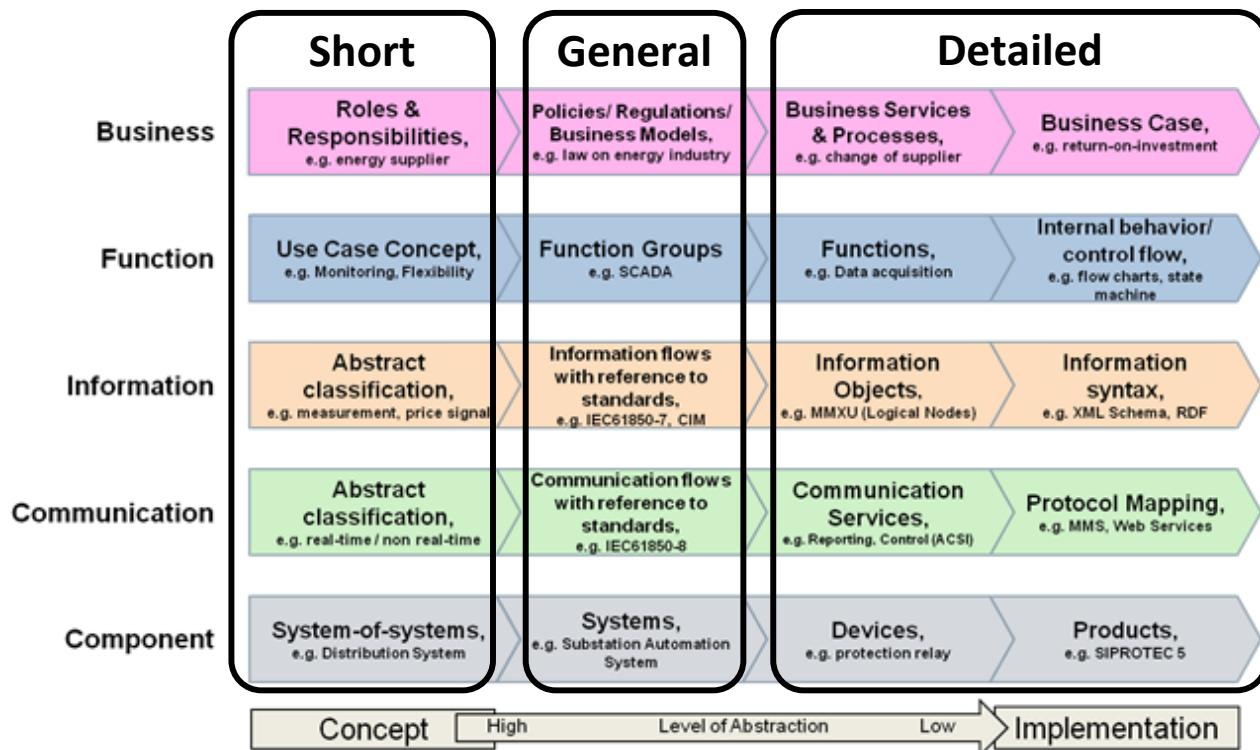


Figure 2.10: Relation of use case templates and the use case analysis pattern based on the SGAM framework [21].

### 2.3 Systematic Process for the Development of the IDE4L Automation Architecture

The conceptual three-step process for developing the architecture described in Section 2.1 is systematically described in this Section. More precisely, the systematic approach for the development of the IDE4L automation architecture leverages on the usage of the two tools previously described, i.e. the Use Case Methodology and its use case templates, and the SGAM framework upon which the IDE4L use cases are mapped and a use case analysis is performed to define the three milestones of the automation architecture: concept, draft, and detailed.

#### 2.3.1 The Three-Step Approach

Figure 2.11 shows the three-step process for the development the IDE4L automation architecture using the use case templates spanned over the time length of the project. The increasing level of detail of the use case descriptions is provided through the use case templates, i.e. short, general, and detailed. The proposed process uses the three templates at different development stages of the project, receiving the key inputs (orange boxes), producing the outputs (blue boxes). The advantage of this process is the following. Due to the “multi-resolution” structure of the templates (the detailed version contains all the info of both the general and the short versions, and the general template contains the info of the short version), a later inconsistency in the use case description, which might reflect in incorrect architectural features, does not require to step back to the beginning (note the retrofitting arrows in Figure 2.11). Moreover, it allows the development of the architecture in parallel with the increasing level of description detail of the use cases, which is another key feature of the project since the progresses in the applicative WPs 4-6 are running in parallel with the automation architecture development done in WP3.

The described process enables the delivery of the crucial milestones for the IDE4L Project WP3. First the concept of the architecture is derived from the use case short template. This concept defines functionalities and modes of operation that the architecture must enable (what the architecture is able to do, what it takes in principle to realize it, in terms of actors, functions, and their interconnections). Then from the use case general template, the draft architecture and the testing features are derived (implementation and integration, and preliminary numerical simulations). Finally, from the use case detailed template the complete, detailed architecture (in terms of infrastructure, information, communication, and functions) is derived, together with the full testing features of the both numerical simulation, Hardware in the Loop – HIL - and in-field demonstrations.

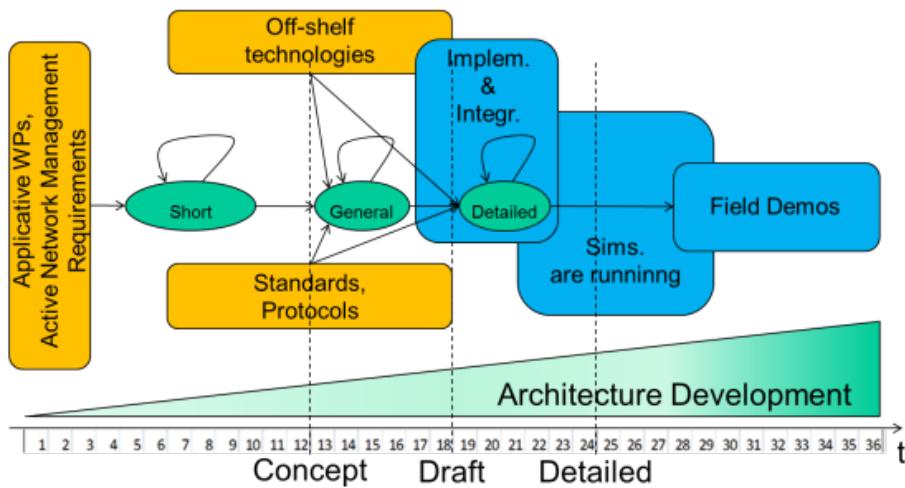


Figure 2.11: The three-step process for the development the IDE4L automation architecture using the use case templates spanned over the time length of the project.

### 2.3.2 The Incremental Approach

What is not evident from Figure 2.11 is the incremental approach, introduced at the beginning of this Chapter, which leverages on the most recently developed automation architectures for the smart grid as a starting point upon which the IDE4L automation architecture will be systematically expanded to fulfill the identified requirements in deliverable D2.1. The chosen starting point architecture comes from the INTEGRIS [4] and ADDRESS [3] projects, other two EU Projects part of the European Seventh Framework Program (FP7). The main reason why the INTEGRIS architecture was chosen is mostly given by its *technical* similarities. In fact, the functions and services in the INTEGRIS architecture are not all centralized, as the monitoring and control algorithms of the different applications may be implemented at various points of the distribution infrastructure (e.g. Primary, Secondary substations). What is missing in the INTEGRIS architecture is the *market orientation*, which is covered by the ADDRESS architecture. The ADDRESS project proposes the active participation of small and commercial consumers in power system markets and provision of services to the different power system participants. The same concepts, i.e. technical from INTEGRIS and business from ADDRESS, are envisioned to be present and implemented in the IDE4L architecture. However, the IDE4L automation architecture has to fulfill wider requirements: not only a greater number of functionalities (use cases), but also the functions and algorithms may also be implemented among different interacting entities (TSO, DSO, Aggregator, Retailer, other service providers). This feature challenges the development of the IDE4L architecture because of the “across domain” and “across business” nature of the system. Hence, the need of the incremental approach emerges to exploit

the mapping onto a comprehensive framework, with partitioning structure that fits for distributed systems, as the SGAM framework.

The adopted methodology is summarized in Figure 2.12. The process of defining the automation architecture consists of the following steps divided by milestones.

To define the automation architecture *Concept*:

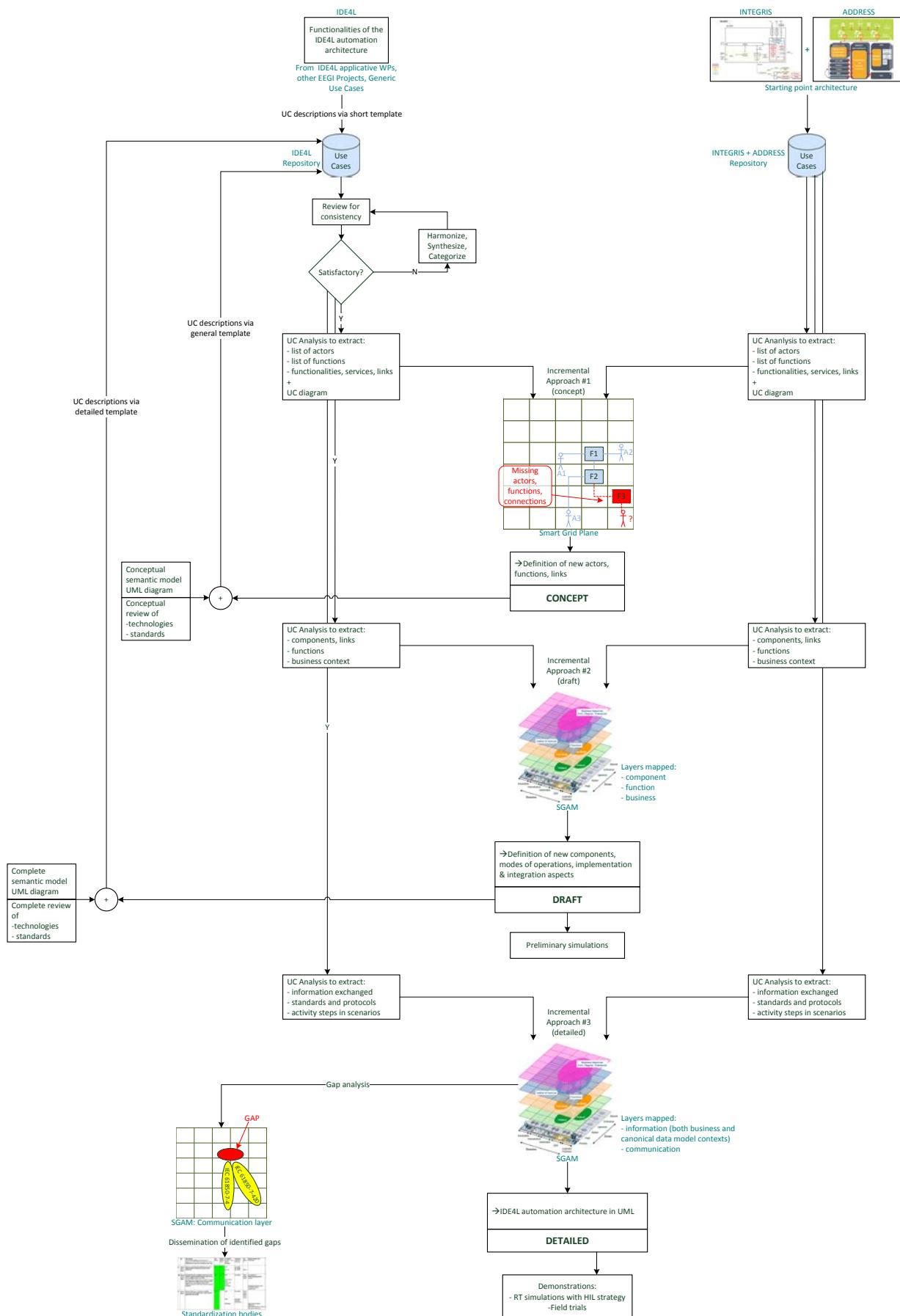
- Collection of IDE4L use cases (UCs) (sources are applications within IDE4L Project, other projects, and envisioned future use cases) via UC short template.
- Review for consistency; if consistent go ahead, if not harmonization, synthesis may be needed for UC refinement.
- For the starting point architecture, the UCs are already collected in a consolidated document [22], and in Deliverables 1.1 and 4.1 [3], for the INTEGRIS and ADDRESS architectures, respectively.
- UC analysis for the extraction of list of actors, list of functions, functionalities, services, and links with the addition of the UC diagram for both the early stage of the IDE4L automation architecture and the INTEGRIS+ADDRESS starting point architecture.
- Mapping of the IDE4L and INTEGRIS+ADDRESS UC diagrams in a unique Smart Grid Plane, by positioning actors and functions in the zones and domains they belong to according to the description in the UC short template. In this way, the missing actors, functions, links are immediately identifiable. Notice that such a mapping will have a direct effect on the SGAM layers in the later stages of the process.
- Delivery the *Concept* of the IDE4L automation architecture by defining new actors, functions, links. Notice that a part of them may come from the starting point architecture, some are totally new, and some may need to be re-defined.

To define the automation architecture *Draft*:

- The defined concept in addition to a conceptual review of standards and technologies currently deployed in distribution automation systems, together with a conceptual semantic model UML diagram (both contributions are part of Ch. 4 of this deliverable) are inputs for the next phase of improving the level of details of the UC descriptions via general template.
- Review for consistency; if consistent go ahead, if not harmonization, synthesis may be needed for UC refinement.
- UC analysis for the extraction of list of components, links, functions, business context for both the IDE4L automation architecture and the INTEGRIS+ADDRESS starting point architecture.
- Mapping of the IDE4L and INTEGRIS+ADDRESS UCs on to the SGAM. The UC diagrams defined in the previous stage will be converted in a physical realization allowing the mapping of the component and function layers. The business context of the UC general template allows also the mapping of the business layer.
- Delivery the *Draft* of the IDE4L automation architecture by defining new components, modes of operations, implementation and integration aspects. Again, notice that a part of them may come from the starting point architecture, some are totally new, and some may need to be re-defined.

To define the *Detailed*, complete automation architecture:

- The defined draft in addition to a complete, comprehensive review of standards and technologies currently deployed in distribution automation systems, together with the final semantic model UML diagram (both contributions will be part of the next deliverable D3.2) are inputs for the final phase of improving the level of details of the UC descriptions via detailed template.
- Review for consistency; if consistent go ahead, if not harmonization, synthesis may be needed for UC refinement.
- UC analysis for the extraction of list of information exchanged, standards and protocols that support the exchange of information, and the step activity in several scenarios for both the IDE4L automation architecture and the INTEGRIS+ADDRESS starting point architecture.
- Mapping of the IDE4L and INTEGRIS+ADDRESS UCs on to the SGAM. The component layer mapped in the previous stage will be projected to the remaining layers of the SGAM. The information (both the business and canonical data model contexts) and communications layers are mapped from the step-by-step analysis and the list of standards.
- Delivery the IDE4L *Detailed* automation architecture formalized in UML.
- Possible identified gaps in technology or standards are disseminated among researchers and standardization bodies.



**Figure 2.12: Systematic process for the development of the IDE4L automation architecture based on the incremental approach.**

### 2.3.3 Mapping Use Cases on to the SGAM

As highlighted in the DISCERN Project [8], three approaches exist to map use cases on to the SGAM: bottom-up, top-down, and mixed. In the bottom-up approach, the specification part takes place first even though the final solution is not known. The top-down approach instead proposes the opposite design flow. The mixed approach is a combination of the two other approaches. Due to the fact that the IDE4L automation architecture is developing in parallel to the applications that the automation system has to support, the mixed approach is the most suitable to map the developing use case descriptions on to the SGAM.

The following explains how to map use cases on to the SGAM based on the inputs the use case descriptions in the templates may provide. First the Smart Grid Plane is mapped by using the use case short template. Then the mapping continues on to the SGAM layers by using the use case general and detailed templates. Figure 2.13 shows the mapping of use cases based on the mixed approach.

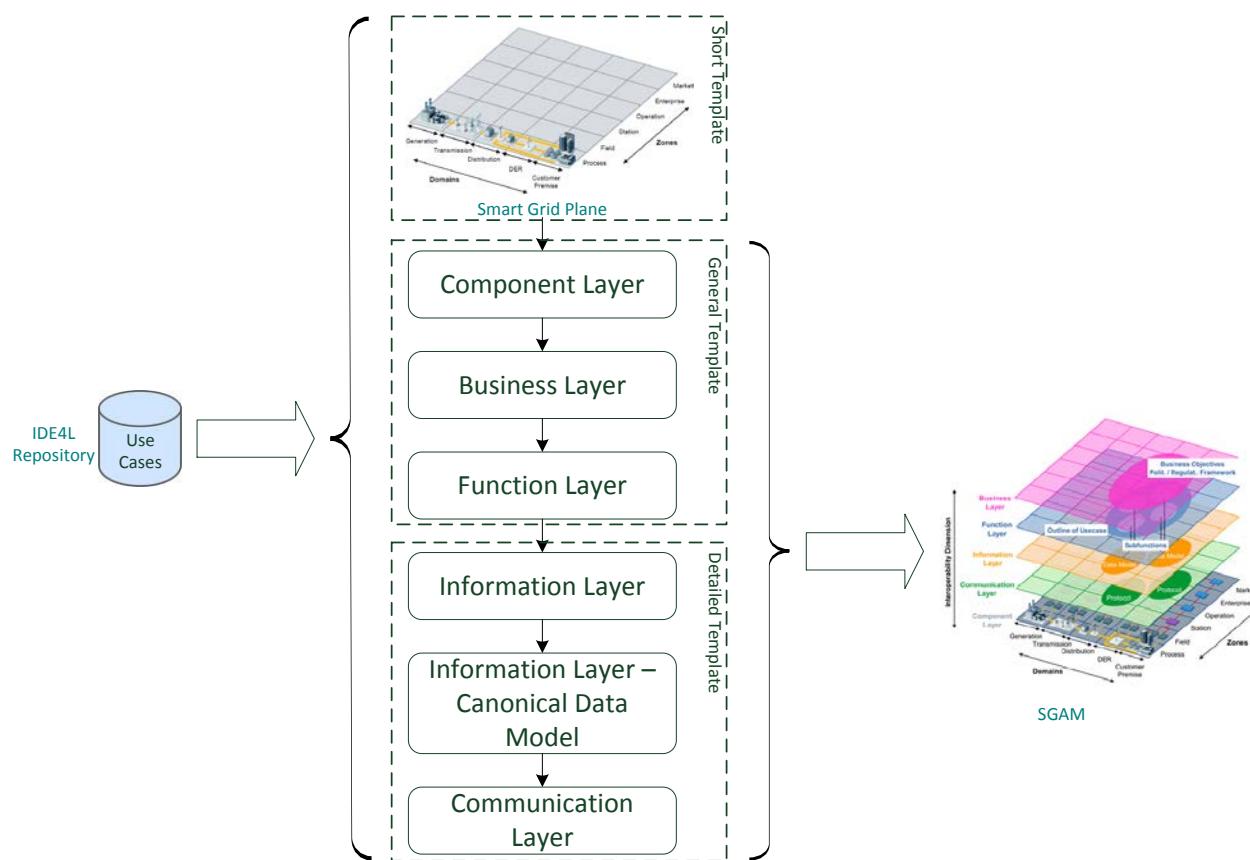


Figure 2.13: Mapping of IDE4L use cases on to the Smart Grid Plane and SGAM based on a mixed approach.

#### Mapping the Smart Grid Plane (Figure 2.14)

The Smart Grid Plane simply consists of actors and functions of the use case diagram mapped to the appropriate domain(s) and zone(s). The connection between actor(s) and function(s) may come from the narrative of the use case in which a high-level step analysis may be included describing what occurs when, why, with what expectation, and under what conditions. All the information to map the Smart Grid Plane is contained in the use case short template.

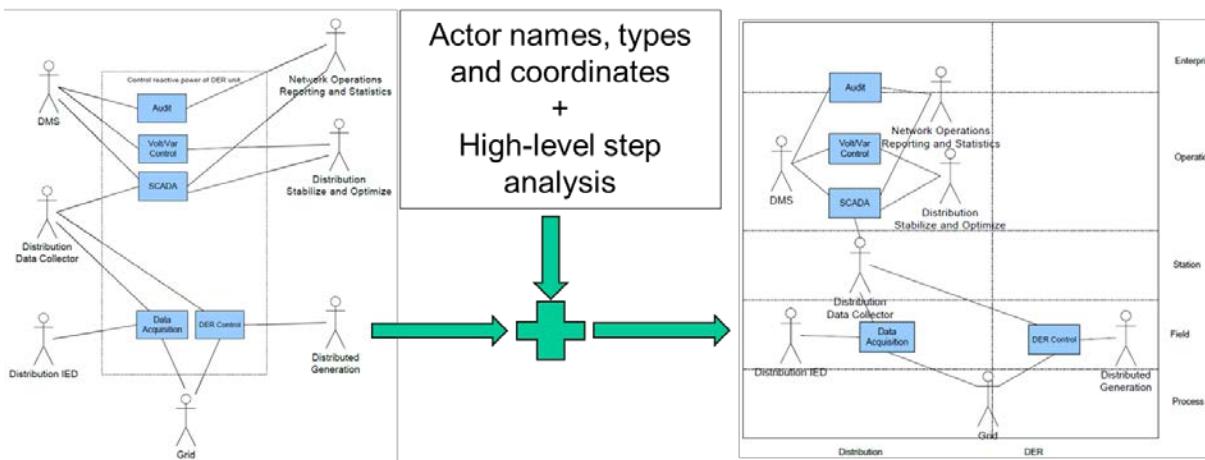


Figure 2.14: Mapping of the Smart Grid Plane.

### **Mapping the Component Layer (Figure 2.15)**

The component layer contains the components able to perform the functionalities described in the use cases. These components include the electrical equipment in the energy conversion chain (process domain in the SGAM) and the other components dedicated for the management of the information, e.g. computers, software applications, etc. The connections between components are of two types: electrical and related to the communication for the information exchange. The component layer can be mapped by using the following inputs:

- actor and functions lists, systematically harmonized and synthesized, which shall be used as reference for the identification of components,
- the use case diagram previously mapped on to the Smart Grid Plane, and
- a conceptual review of off-shelf technologies and standards, an input which is external to the use case general template (see Figure 2.12), which may also provide information on the interfaces needed for the communication infrastructure enabling thus the tracing of the interactions between components.

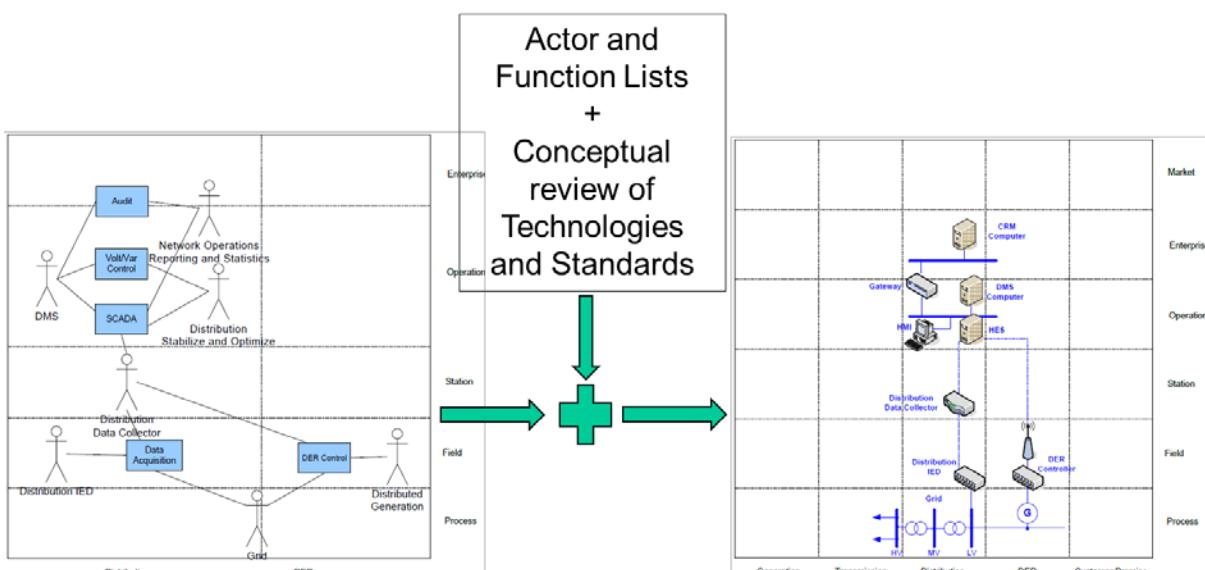


Figure 2.15: Mapping of the SGAM Component Layer.

At the component layer, good examples already exist which can be used as a reference for deriving this layer. Figure 2.16 shows on a level of abstraction of “systems” and the mapping of the most important smart grid systems onto the domains and zones of SGAM as outlined in [23].

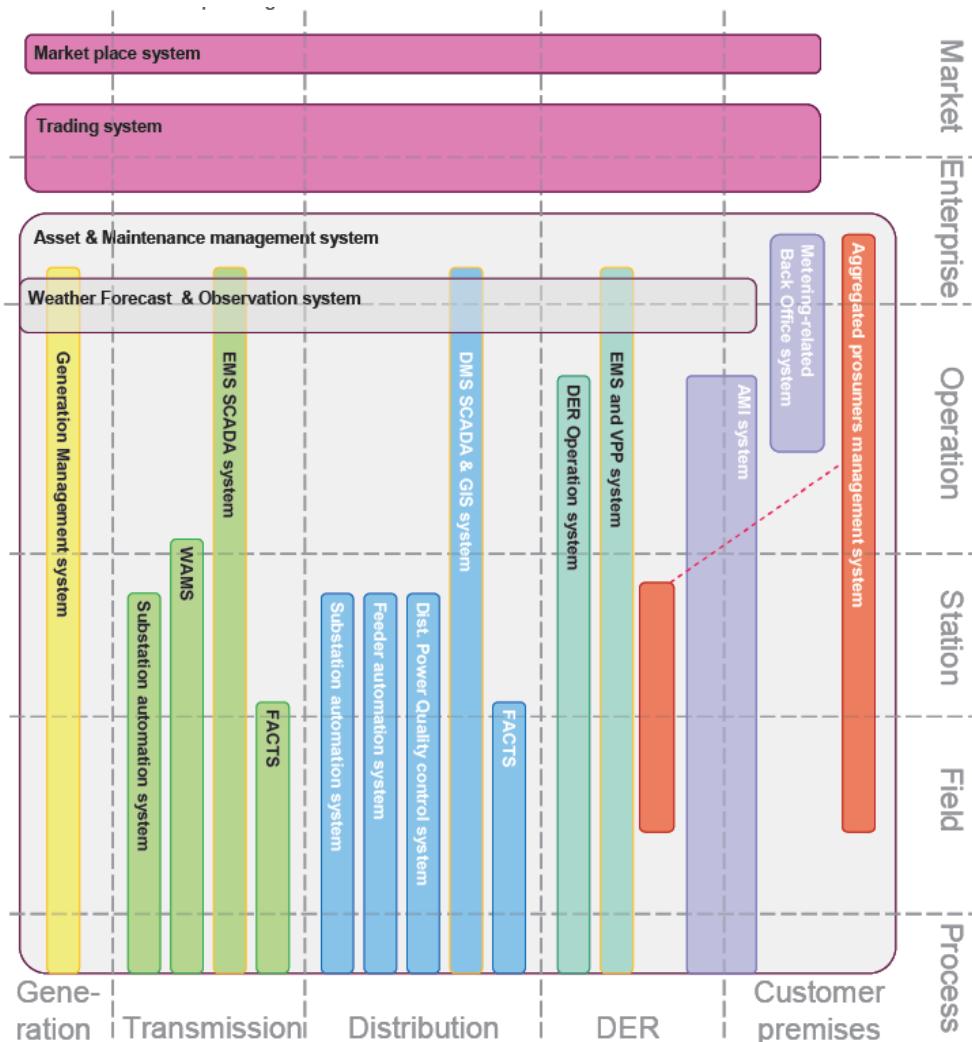


Figure 2.16: Mapping of Smart Grid Systems on the SGAM Component Layer [23].

### Mapping the Business Layer (Figure 2.17)

The business layer covers the business dimension of a use case. More precisely, it contains business objectives and processes, economic and regulatory constraints of the use case. This information is contained in the “Scope and Objectives of the Use Case” which may envision the related business case, the “References/Issues” section which may be used to describe legal issues that might affect the use case operability, including contracts, regulations, policies, financial considerations, etc.

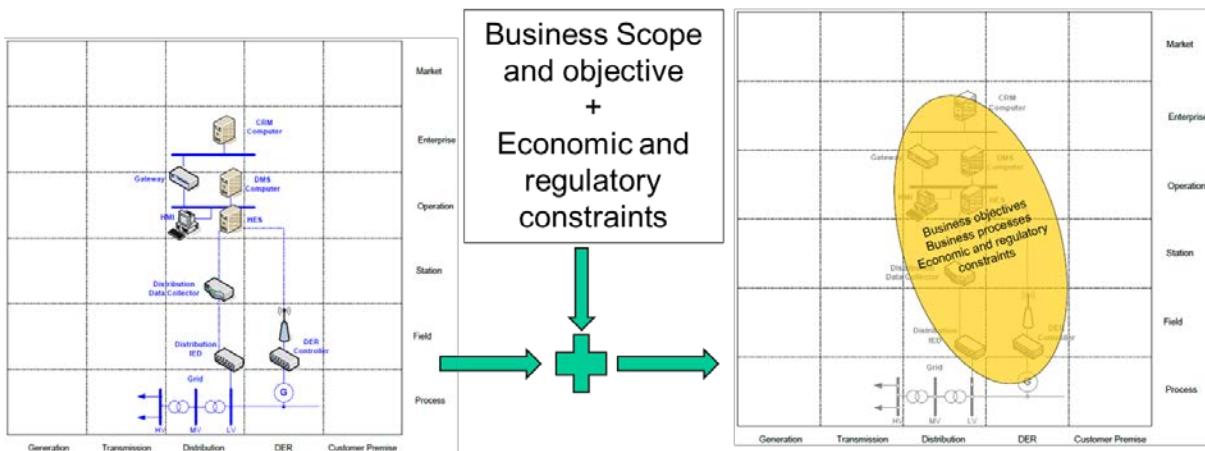


Figure 2.17: Mapping the SGAM Business Layer.

### Mapping the Function Layer (Figure 2.18)

The function layer represents the functional architecture in respect to domains and zones. This layer identifies the technical functions required to realize the functionalities of a use case. The required inputs needed to map the function layer are essentially the use case diagram and the already mapped component layer. The function layer provides an idea where the functions of a use case can be physically implemented.

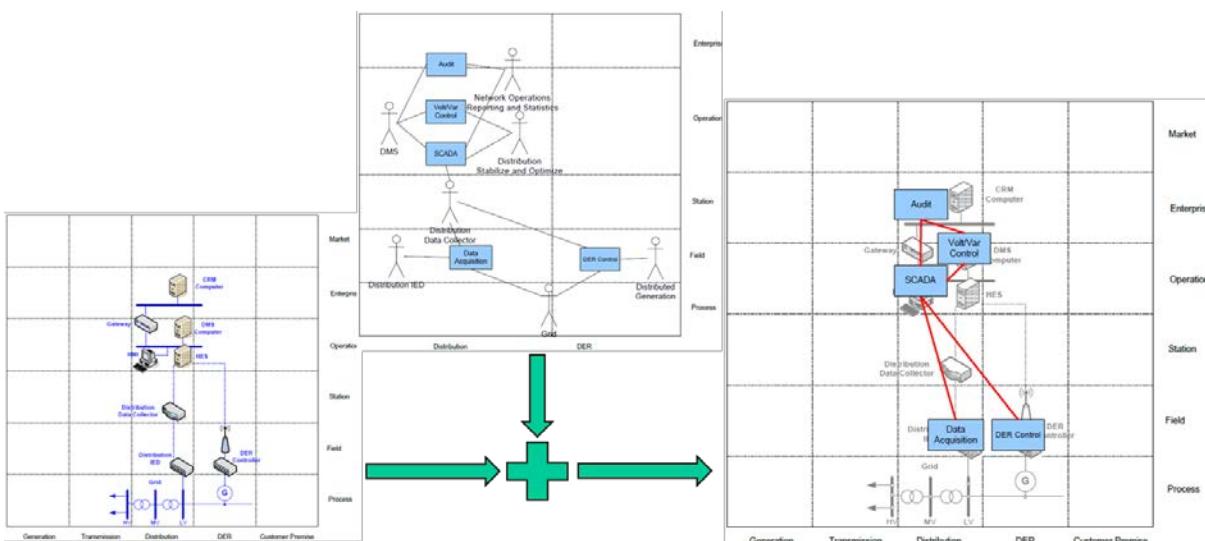


Figure 2.18: Mapping the SGAM Function Layer.

### Mapping the Information Layer – Business Context (Figure 2.19)

The information layer – business context – represents the information objects exchanged between functions, services and components. These information objects can be extracted from the step-by-step analysis of the use case detailed template, and especially from the description of information exchanged. Furthermore, in order to map this layer it is possible to refer the sequence diagram in the form of use case UML diagram.

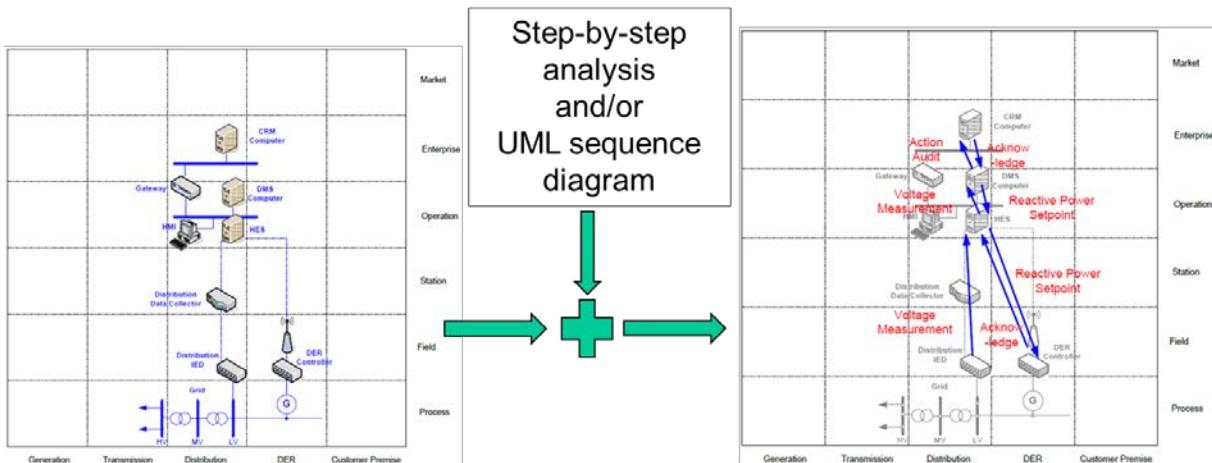


Figure 2.19: Mapping the SGAM Information Layer – Business Context.

### Mapping the Information Layer – Canonical Data Model Context (Figure 2.20)

The information layer – canonical data model context – describes the canonical data model standards used to enable the exchange of information between actors in a use case. This layer can be mapped if standard list is provided which may come from the complete review of off-shelf technologies and standards (see Figure 2.12). A useful tool is the IEC Smart Grid Standards Mapping Tool [24] which may be used to create the list of standards that are needed in support of the IDE4L automation architecture for any SGAM domain/zone (Figure 2.21).

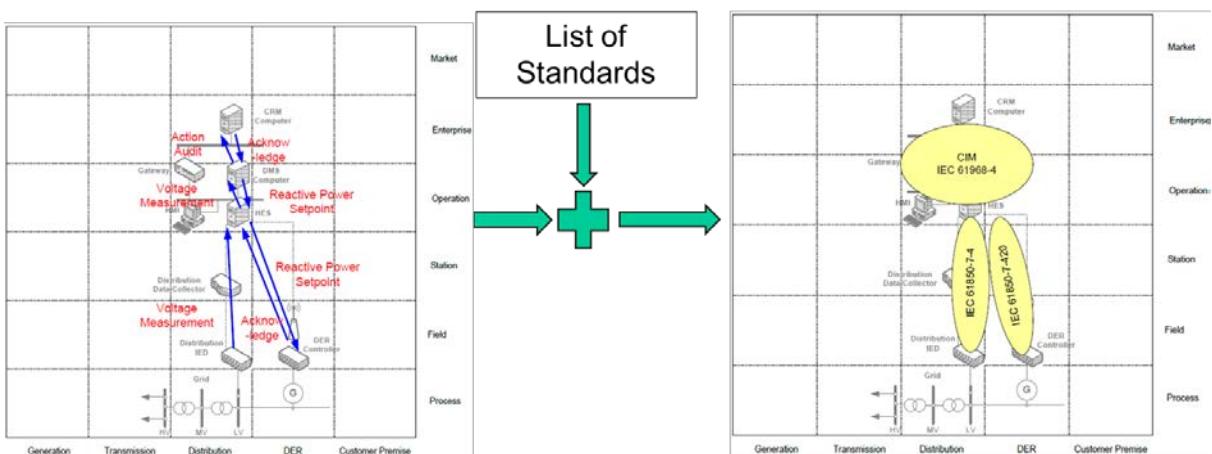
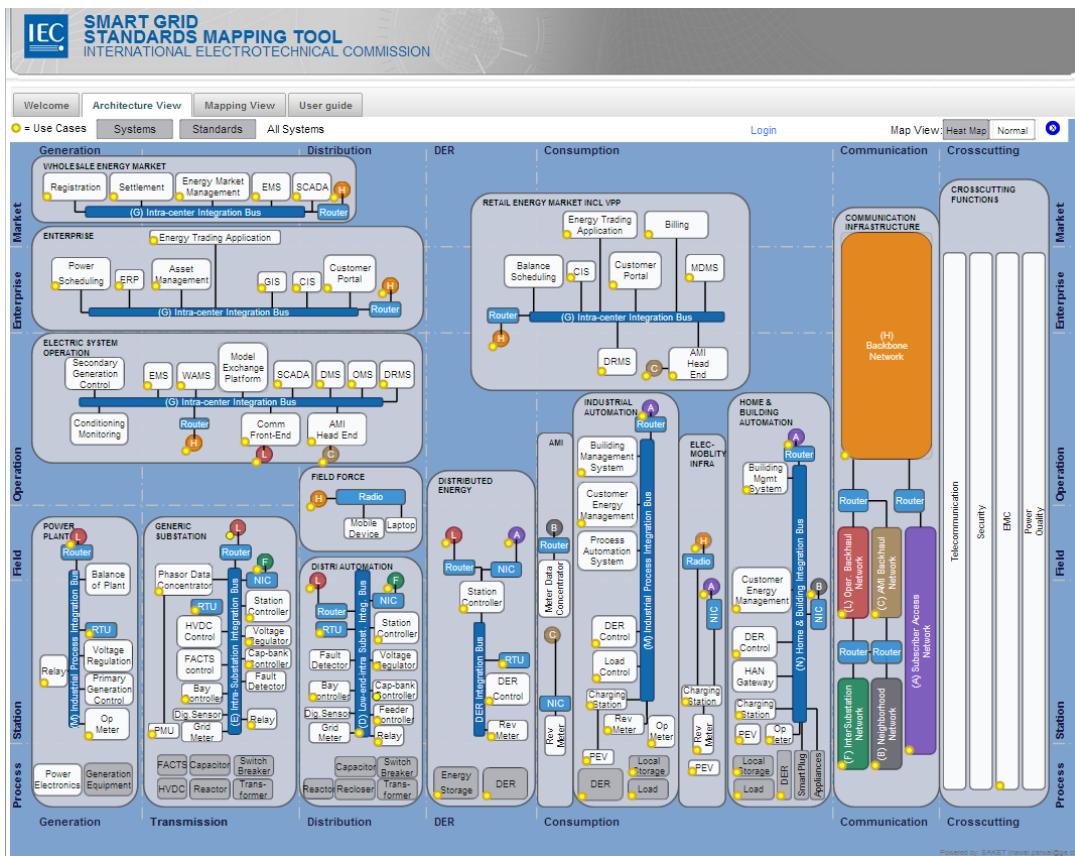


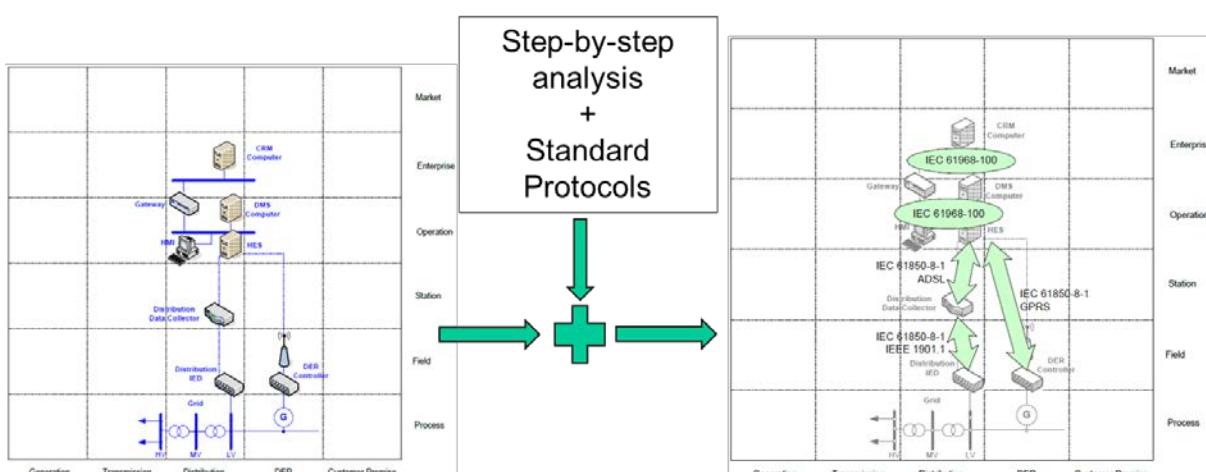
Figure 2.20: Mapping the SGAM Information Layer – Canonical Data Model Context.



**Figure 2.21: IEC Smart Grid Mapping Tool [24].**

## *Mapping the Communication Layer (Figure 2.22)*

The communication layer describes standard communication protocols needed for the interoperable exchange of information between use case actors. The step-by-step analysis contained in the use case detailed template and the input which may come from the complete review of off-shelf technologies and standards (see Figure 2.12) allow to properly mapping this layer. In particular, from the step-by-step analysis the actual connections between components (the component layer is already mapped) may be inferred. Then, once the connections between components are known, the standard communication protocols can be identified in support to the identified connections.



**Figure 2.22: Mapping the SGAM Communication Layer.**

### 3. The Automation Concept for Distribution Networks

The main goal of this deliverable D3.1 is the definition of the distribution automation concept. In a few words, what we mean with the automation concept (we drop the word “distribution” hereafter) is the following:

- functionalities and modes of operation that the architecture must enable (what the architecture is able to do, what it takes in principle to realize it, in terms of infrastructure, information, communication, and functions).

In practice, the procedure described in Chapter 2 is here adopted to define the automation concept. This is accomplished by providing the complete list of actors, functions, links between actors and functions, their high level descriptions and mapping into the smart grid plane. In the IDE4L project, we have defined a set of use cases containing a certain number of actors, functions and links. Use cases, actors, functions and links have been compared to the corresponding ones defined in the starting point architecture. Based on this comparison, we have come up with the final definition for the automation concept for distribution networks that will be adopted in the IDE4L project.

The automation concept is built up based on use case descriptions coming from the applicative WPs 2, 4, 5, 6 and from the demo WP7 as well as from experience of other EU Projects (e.g. INTEGRIS and ADDRESS).

This concept, due to the complexity of the system as we are talking about “a system of systems”, is hardly synthesizable in a single paragraph. Figure 3.1 depicts the IDE4L overall automation architecture concept mapped on to the Smart Grid Plane. The figure is meant to show such a complexity through the density of actors and functions in the smart grid plane.

For the sake of completeness and “digestibility” of the contents, a structured argumentation is proposed in the following sections. In Section 3.1, the use cases (UCs hereafter) will be described in the following order: UC Clusters, High Level UCs (HLUCs), and Primary UCs (PUCs). Then, the starting point architecture is provided in Section 3.2 by describing the UCs coming from the existing projects INTEGRIS and ADDRESS. Section 3.3 explains the incremental approach highlighting the portions of the IDE4L architecture that come from the starting point architecture and “the new items” that IDE4L project proposes. The result of this increment is the synthesis of the lists of actors, functions and links with the goal of eliminating all possible redundancies. Finally, some assessment on the performance of the IDE4L architecture is given in Section 3.4.

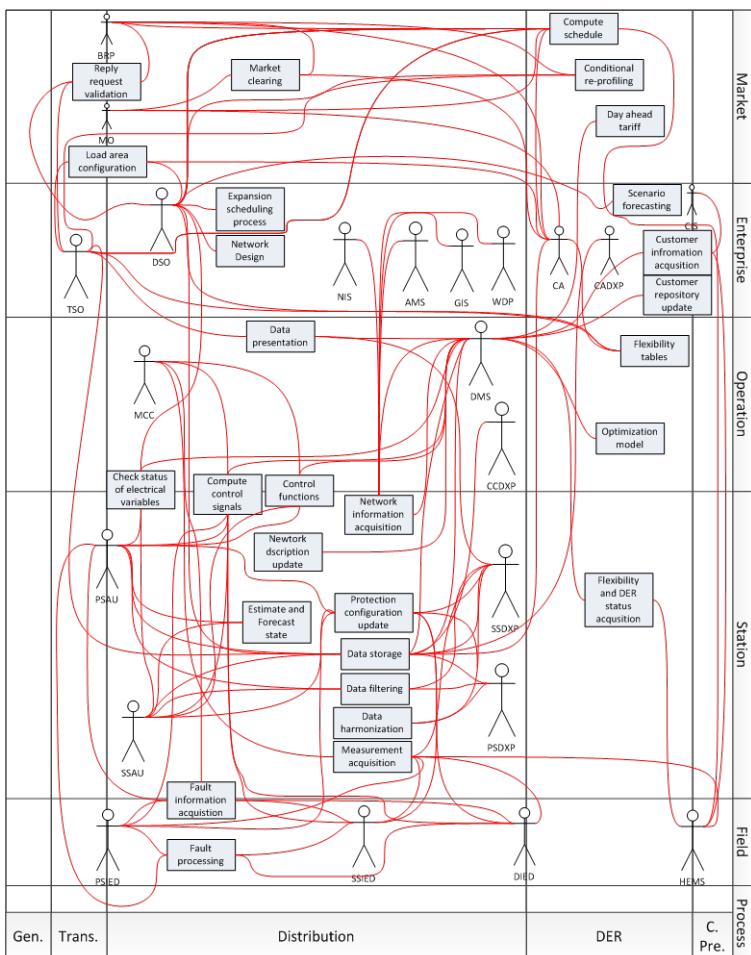
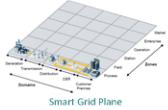


Figure 3.1: IDE4L overall automation architecture concept mapped on to the Smart Grid Plane.

### 3.1 Analysis of IDE4L Use Cases

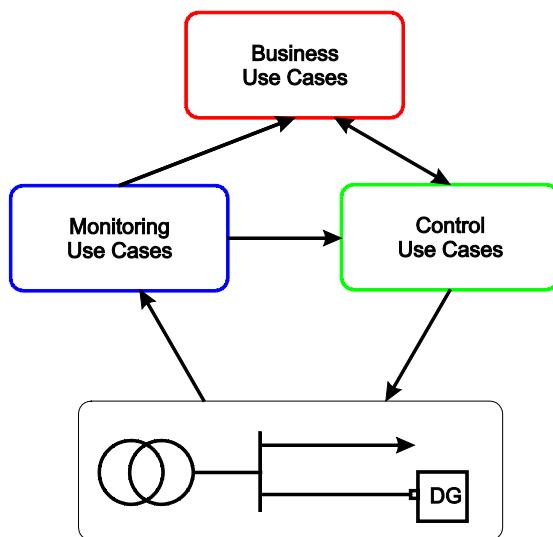
Work package 3 (WP3) produced a total of 26 PUCs. As described in the previous chapters, the goal of the use cases is to define the functionalities that the smart grids should be able to offer within the target year. From the descriptions of the use cases is it possible to infer actors, functions and data exchange which enable such functionalities.

#### 3.1.1 Clusters of Use cases

The UCs produced within WP3 are extremely heterogeneous, covering all the meaningful areas of the IDE4L project. Consequently, there was the need for collaboration among different fields' experts within WP3 in order to adequately harmonize and synthetize the descriptions of the use cases. Clustering the UCs is the first step for a division in areas of competence, and gives a first general view on the main directions in which IDE4L tends to develop the concept of automation. The UC clusters are indicated in the following list:

- Monitoring
- Control
- Business

Figure 3.2 shows an indicative scheme for IDE4L UC Clusters with their conceptual interconnections. At this level of description, complete accurateness in the functionality definition is not required.



**Figure 3.2: Scheme for IDE4L UC Clusters.**

### **Monitoring use cases**

The Monitoring use case cluster describes how to measure electrical quantity of distribution networks including MV feeders, secondary substations and LV networks. Active distribution networks have clear interest to monitor those parts of networks where the hosting capacity of network may occasionally be exceeded or the continuity of supply is a concern. Besides, the paradigm shift towards Smart Grids requires a tighter interaction of TSOs and DSOs through exchange of key information of specific active distribution network dynamics. This cluster is responsible for providing the Control and Business use case clusters information about the grid model, the grid status, and the customers' status at current and future instants in time. In a few words this cluster represents the enabling technology which allows the automation functionalities in the IDE4L architecture.

### **Control use cases**

The Control use case cluster describes how the monitored quantities are processed by automatic control actions which may be located at the Field level (totally distributed and implemented in IEDs), at both secondary and primary substations (partially distributed) and control centers (totally centralized). DERs, like distributed generation, demand response loads, storage, microgrids, STATCOM and OLTCs usually are under the DSO's direct control. Therefore, the Control use case cluster is able to provide a direct control action on the grid starting from measured quantities coming from the Monitoring use case cluster. On the other hand, small-scale DERs that do not fall under the direct supervision of the DSO are grouped under an Aggregator. In this latter case, the Control use case cluster can provide control actions on the grid by receiving inputs (and provide outputs) from (to) the Business use case cluster where the concept of Aggregator is located, which is the entity able to operate on the energy market to sell ancillary services to the DSO itself or to the TSO.

### **Business use cases**

The Business use case cluster describes how the process of energy and service trading takes place. The main actor in this cluster is the Aggregator under which the DERs can be grouped. The Aggregator is able to operate on the energy market as one, or sell services to the DSO and TSO. Both DSO and TSO can use the

flexibilities for congestion management as a substitute for infrastructure investments. Once the services are traded, the Business use case cluster can communicate with the Control use case cluster to perform the needed feasible technical service on the grid through the monitored and controlled DERs via the Monitoring and Control use case clusters, respectively.

### 3.1.2 High Level use cases

A High level use case (HLUC) describes a general requirement, idea or concept independently from a specific architectural solution. The HLUCs defined in IDE4L project are ten and here listed:

- Monitoring cluster
  - Real time monitoring
  - Forecast
  - System updating
- Control cluster
  - Power control
  - Protection
  - Power quality
  - Network planning
- Business cluster
  - Interaction among Commercial Aggregator, DSO and TSO – Operation Domain
  - Interaction among Commercial Aggregator, DSO and TSO – Market Domain
  - Grid tariffs

A brief explanation for each of them is given here in order to provide the reader with a growing awareness of the IDE4L automation concept, but without demanding a complete level of definition, given the nature itself of HLUCs.

Real time monitoring includes the collection, filtering and storage of information coming from measurement devices installed in the grid and from information services such as custom information system (CIS) and network information system (NIS). The computation of some measurements, like state estimation algorithm, in order to obtain high quality data, such as power quality or security indexes is included. Forecast HLUCs include the procedure to request user, weather and other data in order to obtain forecast load and production tables in different time ranges. System update HLUCs contain the use cases for updating grid information when new pieces of grid or new user are added, or when the network configuration is changed due to reconfiguration after faults.

Power control use cases include 3 levels of control starting from local device control, going to substation automation actions and finally to control centers. FLISRs identify the use cases for fault isolation and grid reconfiguration in order to restore power supply in the shortest time for the highest number of users. Power qualities represent the control actions taken in order to reduce quality issues in the voltage of the system. Network planning describes the planning process to design network structure with minimal costs.

Eventually in the business cluster the Commercial Aggregator HLUCs describe the procedure for the purchasing of energy and flexibility service in the distribution grid. The Grid tariff Use cases represent the method to influence DERs by means of tariff signals.

Figure 3.3 shows the information exchange of the IDE4L HLUCs, without demanding for complete and exact functionality description, given the High level of description. In grey color, some actors which are not part of the automation architecture itself are represented. They are important terminals for the information exchange with the IDE4L architecture.

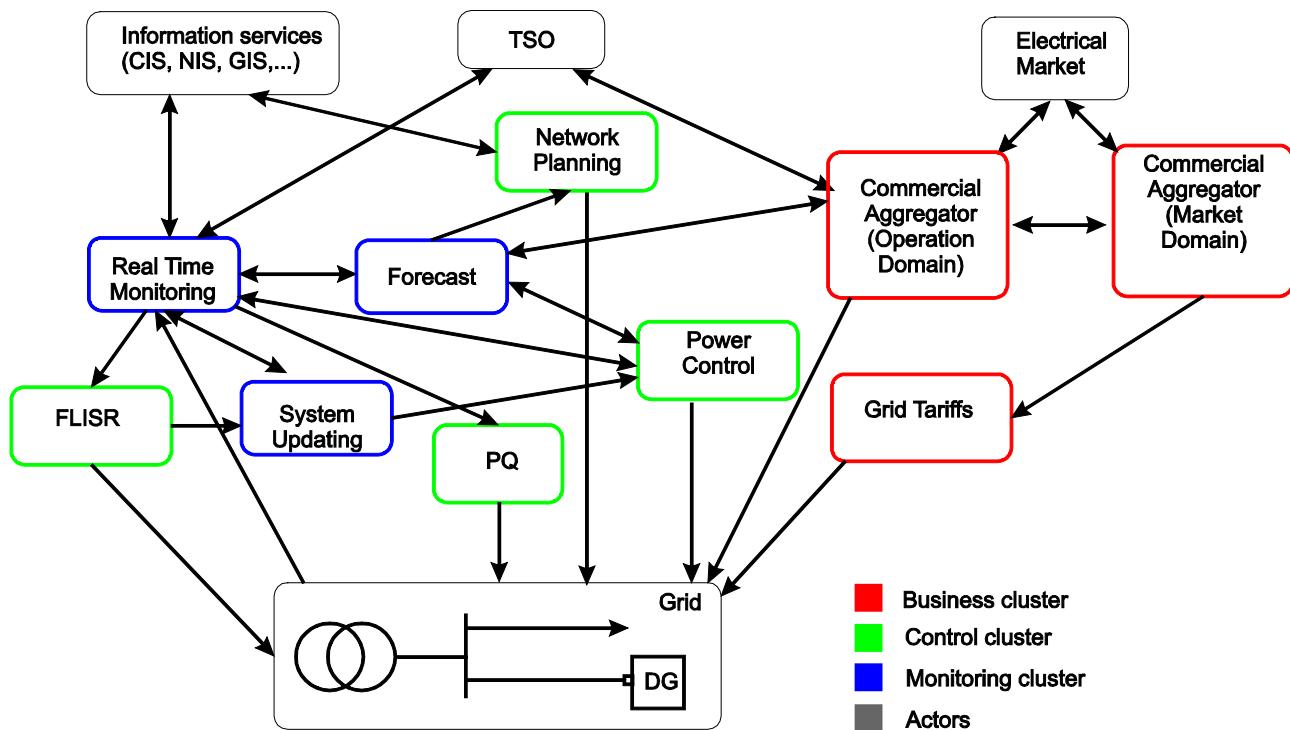


Figure 3.3: HLUCs schematic, with synthetic representation of information exchange.

### Real time monitoring

Due to the increasing number of DERs providing energy to the distribution grid on the lower voltage levels, the need for better monitoring the grid is increasing in order to supervise, e.g., the voltage values or power ratings. Once connected with a communication line, the new smart grid devices (Smart Metering, Substations) and their communication capabilities can be exploited for further improving the “visibility” of the grid at low voltage levels. This information can also be provided to the DSO’s SCADA system for further evaluations (e.g. fault identification, outage monitoring, etc.).

### Forecast

The load and generation profiles are forecasted several hours ahead, e.g. for the next day, according to weather forecasts, historic load and generation profiles, and scheduled events (e.g. social, generation maintenance events, etc.). The DSO has to be able to forecast generation and consumption to monitor and plan operation of the distribution system in the short term situations. Generation and consumption can be forecasted within various time horizons with different precision. Needed data are gathered from, e.g. historical data, planned up-times, prosumer vacation/travel times and maintenance schedules.

### System updating

Whenever the distribution network undergoes a change (topology, assets, customers, protections), the DSO needs to record that event. This information is needed to perform correctly algorithms (State Estimation, State Forecasting, Optimal Power Flow, etc.) and to control actions in order to increase the network reliability and performance.

### ***Power control***

This function optimizes the voltage profile and power flows to maintain stable voltage at customer site in a defined area of the distribution grid with distributed generators, flexible loads and other deployed power equipment. The main optimization criteria can be extended to supply ancillary services to the grid at upper level and pursue operating costs minimization.

### ***Protection***

Protection high level use case is also mentioned as Fault Location Isolation and Service Restoration (FLISR) high level use case; it automates the management of faults in the distribution grid. It supports the localization of the fault, the isolation of the fault and the restoration of the energy delivery. During disturbances the automatic fault handling shortens outage time and offloads the operators in the distribution control center for more complicated situations. Therefore FLISR may help to improve performance indexes like SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index). As FLISR is creating switching proposals to reconfigure the network, corresponding safety aspects need to be considered and implemented.

The FLISR use case is divided into four sequences:

1. Fault detection and clearance – The protection devices in the grid are detecting the fault and issuing suitable breaker tripping.
2. Fault localization – Identify the physical location of the fault by analyzing the telemetered alarms received from protection devices in the grid
3. Fault isolation – Determine switching actions which will isolate the faulty equipment from the rest of the grid
4. System restoration – Resupply those healthy parts of the grid, which are de-energized during the fault clearing.

### ***Power quality***

The aim is to propose methods to improve power quality in LV/MV networks with high penetration of power electronics-based generating units and/or other equipment. Regulations indicate minimum threshold power quality levels that installations have to fulfil for their network connection. For instance, flicker and harmonic emission at the point of connection of renewable energy resources are regulated and such installations should ensure the accomplishment of these standards to obtain the license for their commissioning. Excessive flicker levels, harmonic voltage and currents, oscillations in frequency and voltage levels could produce the malfunctioning and even the fault of the equipment and loads connected, so measures are needed for the protection of such consumers.

### ***Network planning***

The distribution network planning is a task of the DSO. The scope of this function is the planning and design of active distribution networks. The customer and the DER have to be considered in the planning process as well as the operation of all controllable smart grid components. The objective of the planning process is to design a secure and reliable network structure by keeping an inexpensive network operation if possible for a given future generation and demand scenario.

### ***Interaction among Commercial Aggregator, DSO and TSO – Operation Domain***

This use case describes the interaction between the TSO and the DSO, and between the DSO and the aggregator needed to produce offerings of ancillary and flexibility services in load and (distributed) generation areas and eventually to activate them. Thereby, first the so-called flex-offers are issued

indicating these power profile flexibilities, e.g. shifting in time or changing the energy amount. Then, flex-offers are dynamically scheduled in near real-time, e.g. in case when the energy production from renewable energy sources, such as wind turbines, deviates from the forecasted production of the energy system.

### ***Interaction among Commercial Aggregator, DSO and TSO – Market Domain***

This use case describes the interaction between the flexibility buyers (DSO and/or TSO) and the aggregator on how they make market offerings, accept and assign demand or generation flexibility. The central concept of the approach is the flex-offer specification. Essentially, a flex-offer is a request for demand or supply of energy with specified flexibilities. These offerings are negotiated by a process of offering, accepting or rejecting, possibly followed by providing a different offering. Reasons for accepting and rejecting include suitability of the offered flexibility (the expected value of the flexibility in e.g. a portfolio) and financial aspects. Finally after successful negotiation, the acquired flexibility exercised by the acquiring party. Exercising an accepted offering is done by assigning the variables in the offering which define the flexibility, i.e. time, power/energy and finance.

### ***Grid tariffs***

Grid congestions need to be managed by matching the capacity through a bottleneck in the power grid with the power flow through it. This can be done by lowering the power consumption (load) or raising the power production on the side of the bottleneck of the power flows. Typically this would be needed where the consumers are. The strategy to avoid congestions is the demand response. If there is congestion, the DSO will determine a dynamic tariff to influence the flexible demands by putting an extra cost of electricity consumption.

#### **3.1.3 Primary use cases**

PUCs are collected via use case short template. The template with explanations of all the fields is reported in Annex 2, while the 26 PUCs, reported in Table 3.1, the IDE4L project proposes are described in Annex 6. In Annex 6, the IDE4L PUCs are described according the following scheme: a complete description including scope and goal of the UC follows a step analysis, and the use case diagram is given where actors and functions are mapped into the Smart Grid Plane.

**Table 3.1: IDE4L PUCs grouped by HLUCs and Clusters**

Clusters	High Level Use Cases	Primary Use Cases
Monitoring	RT-Monitoring	<ul style="list-style-type: none"> <li>• MV Real-Time Monitoring</li> <li>• LV Real-Time Monitoring</li> <li>• MV State Estimation</li> <li>• LV State Estimation</li> <li>• Dynamic Monitoring for TSO</li> </ul>
	Forecasting	<ul style="list-style-type: none"> <li>• MV Load and State Forecast</li> <li>• LV Load and State Forecast</li> </ul>
	System Updating	<ul style="list-style-type: none"> <li>• Network Description Update</li> <li>• Protection Configuration Update</li> </ul>
Control	Power Control	<ul style="list-style-type: none"> <li>• MV Network Power Control</li> <li>• LV Network Power Control</li> <li>• Control Center Network Power Control</li> </ul>
	FLISR	<ul style="list-style-type: none"> <li>• Decentralized FLISR</li> <li>• Microgrid FLISR</li> </ul>
	Power Quality	<ul style="list-style-type: none"> <li>• Power Quality Control</li> </ul>

	Network Planning	<ul style="list-style-type: none"> <li>• Target Network Planning</li> <li>• Expansion Planning</li> <li>• Commercial Aggregator Asset Planning</li> </ul>
Business	Interaction among Commercial Aggregator, DSO and TSO – Operation Domain	<ul style="list-style-type: none"> <li>• Load Area Configuration</li> <li>• Flexibility Table</li> <li>• Off-Line Validation</li> <li>• Real-Time Validation</li> </ul>
	Interaction among Commercial Aggregator, DSO and TSO – Market Domain	<ul style="list-style-type: none"> <li>• SRP and CRP Day-Ahead and Intra-Day Market Procurement</li> <li>• Conditional re-profiling activation (CRP Activation)</li> </ul>
	Grid Tariffs	<ul style="list-style-type: none"> <li>• Day-Ahead Dynamic Tariff</li> <li>• Day-Ahead Demand Response</li> </ul>

### 3.1.4 Synthesis and Harmonization

In the previous subsections, the automation architecture functionalities were described and clustered in UCs. In this subsection, the task that has to be done is the “synthesis and harmonization” of PUCs, i.e. to extract functionalities, modes of operation, services, actors and links between actors from the PUCs. This task is the result of the collaboration among UC authors and review groups, involving various iterations in order to deliver the automation concept.

#### *Synthesis of actors*

Actors in IDE4L architectures are compliant with the definition [16] and represent operators, companies, devices which generate inputs or receive outputs from functions. The goal of the task called “synthesis of actors” is to present a synthetic and clear actors’ framework, avoiding redundancies by maintaining consistency of the roles that each actor may play in the different functionalities of the architecture.

In the following of this subsection, the list of the actors is first given and then each actor is described by defining its role within each UC. Table 3.2 presents the synthesized list of actors.

**Table 3.2: Actors in IDE4L architecture.**

	actors
1.	Distributed Intelligent Electronic Devices (DIEDs)
2.	Primary Substation Intelligent Electronic Devices (PSIEDs)
3.	Secondary Substation Intelligent Electronic Devices (SSIEDs)
4.	Primary Substation Automation unit (PSAU)
5.	Secondary Substation Automation Unit (SSAU)
6.	Microgrid central controller (MCC)
7.	Primary Substation Data eXchange Platform (PSDXP)
8.	Secondary Substation Data eXchange Platform (SSDXP)
9.	Control Center Data eXchange Platform (CCDXP)

10.	Transmission system operator (TSO)
11.	Distribution system operator (DSO)
12.	Distribution Management System (DMS);
13.	Commercial Aggregator (CA)
14.	Balance Responsible Party (BRP)
15.	Market operator (MO)
16.	Weather data provider (WDP)
17.	Customer information service (CIS)
18.	Network information service (NIS)
19.	Geographic information system (GIS)
20.	Asset management system (AMS)
21.	Geographic information system (GIS)
22.	Home Energy management system (HEMS)

#### Distributed Intelligent Electronic Devices (DIEDs)

DIEDs represent the interface between sensors/actuators and monitoring and control application in the distribution grid and in the DG units of the prosumers. In particular, they may represent the interface to recloser in distribution feeders, distributed generators connected on the LV and MV network, and distributed power quality meters.

They can provide measurements and send control signals in protocols and message formats suitable for distribution architecture automation systems. Given the distributed nature of such devices, the most likely protocols are the IEC61850 (GOOSE, SV, MMS), Modbus and DLMS/COSEM. Even if with different targets, sometimes as meters and sometimes as controllers, they take part in the following UCs:

1.	LV Real-Time Monitoring in terms of monitoring devices such as distributed Meter data concentrator, Power quality meters, RTUs and IEDs.
2.	LV Network Power Control and MV Network Power Control in terms of Primary controllers (which can be a PV inverter or some banks of capacitors).
3.	Protection Configuration Update
4.	In with Power Quality Control they represent the ancillary service provider controller, usually DGs.
5.	In Microgrid FLISR, the IEDs represent the interconnection

	switches, which are smart power switches capable to detect a local fault in the grid or to receive disconnection orders from other actors such as PSAU, SSAU or commercial aggregator. When the interconnection switch manages to isolate the microgrid, messages will also be sent to high level agents to inform it about microgrid status. Furthermore the distributed generators are here also represented through IEDs.
6.	In Decentralized FLISR use case, it is the interface with the grid and the Fault management IED which manages its own circuit breaker, detect the fault, extract the fault relative information and send peer messages with the other IEDs and the DXP in substation.

### Primary Substation Intelligent Electronic Devices (PSIEDs)

PSIEDs have similar features as the Distributed Intelligent Electronic Devices (DIEDs) except for the fact that they are placed in primary substation. They may represent all the several types of IEDs and controllers in substation environment such as interface to Sensors, OLTCs, switches, RTUs, PMUs, merging units etc. Even if with different targets, sometimes as meters and sometimes as controllers, they take place in the following UCs:

1.	Dynamic Monitoring for TSO : in terms of PMUs, PDCs and RTUs.
2.	MV Real-Time Monitoring in terms of monitoring devices such as distributed Meter data concentrator, Power quality meters, RTUs and IEDs.
3.	Protection Configuration Update
4.	Network Description Update
5.	MV Network Power Control and Control Center Network Power Control in terms of Primary controllers (for instance the OLTC of the primary substation).
7.	In Microgrid FLISR, the IEDs represent the interconnection switches.
8.	In Decentralized FLISR use case, they are the interface with the grid and the Fault management IED.
9.	In Power Quality Control, they represent the ancillary service provider controller.

### Secondary Substation Intelligent Electronic Devices (SSIEDs)

SSIEDs have similar features as the Distributed Intelligent Electronic Devices (DIEDs) and Primary Substation Intelligent Electronic Devices (PSIEDs) except for the fact that they are placed in secondary substation. They

may represent all the several types of IEDs and controllers in substation environment such as interface to Sensors, OLTCs, switches, RTUs, PMUs, merging units etc. Even if with different targets, sometimes as meters and sometimes as controllers, they take place in the following UCs:

<b>1.</b>	Dynamic Monitoring for TSO : in terms of PMUs, PDCs and RTUs.
<b>2.</b>	LV Real-Time Monitoring and MV Real-Time Monitoring in terms of monitoring devices such as distributed Meter data concentrator, Power quality meters, RTUs and IEDs.
<b>3.</b>	Protection Configuration Update
<b>4.</b>	Network Description Update
<b>5.</b>	MV Network Power Control, LV Network Power Control and Control Center Network Power Control in terms of Primary controllers.
<b>6.</b>	In Microgrid FLISR, the IEDs represent the interconnection switches.
<b>7.</b>	In Decentralized FLISR use case, they are the interface with the grid and the Fault management IED.
<b>8.</b>	In Power Quality Control, they represent the ancillary service provider controller.

#### Primary Substation Automation Unit (PSAU)

It represents the unit which is in charge of processing the data at primary substation level<sup>2</sup>. More precisely, it processes the model and the state of the system in order to perform monitoring and control applications. It takes place in the following use cases:

<b>1.</b>	MV Real-Time Monitoring
<b>2.</b>	Real-Time MV State Estimation
<b>3.</b>	MV Load and State Forecast
<b>4.</b>	MV Network Power Control
<b>5.</b>	Control Center Network Power Control
<b>6.</b>	In Decentralized FLISR use case, it is the interface with the grid and the Fault management IED which manages its own circuit

<sup>2</sup> In practical implementations the SAUs (both in primary and in secondary substation) cover the following roles: functionality, interfaces, and database. However, for the sake of the concept description it has been necessary to logically divide the part of functionalities from the part of data handling (both interface and storage). Consequently, the SAU has been assigned to the management of the functionalities; meanwhile, the data exchange platforms (DXPs) include interface and database.

	breaker, detects the fault, extract the fault relative information and send peer messages with the other IEDs and the DXP in substation.
7.	Microgrid FLISR
8.	In Protection Configuration Update, it updates the status and the parameters of the protections.
9.	Power Quality Control

### Secondary Substation Automation Unit (SSAU)

It represents the unit which will be in charge of process the data at secondary substation level. More precisely, it processes the model and the state of the system in order to perform monitoring and control applications. It takes place in the following use cases:

1.	LV Real-Time Monitoring
2.	Real-Time LV State Estimation
3.	LV Load and State Forecast
4.	In Protection Configuration Update, it updates the status and the parameters of the protections.
5.	Power Quality Control

### Microgrid Central Controller (MCC)

The centralized microgrid controller manages the microgrid to perform the reconnection protocol. It receives the information from the interconnection switch (Distributed Intelligent Electronic Devices (DIEDs), Primary Substation Intelligent Electronic Devices (PSIEDs) and Secondary Substation Intelligent Electronic Devices (SSIEDs)). The monitoring has a fixed position in the microgrid, most likely secondary or primary substation. It takes place in the following use cases:

1.	Microgrid FLISR
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### Primary Substation Data eXchange Platform (PSDXP)

It is a platform for exchanging and storing data at primary substation level. It includes interfaces to accept several protocols, such as GOOSE, MMS from IEC 61850, DLMS/COSEM and CIM. Moreover, it includes filters for bad data detection and extraction of meaningful information, databases with different tables for several categories of data. The DXP should contain an Interface layer which implements those protocols and extract data from other systems and a Data layer, with a database, where the data are written. It takes over the role of Meter data management system (MDMS), Phasor data concentrator (PDC) Meter data concentrator (MDC). It takes place in the following use cases:

1.	MV Real-Time Monitoring and LV Real-Time Monitoring
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<b>2.</b>	Real-Time MV State Estimation
<b>3.</b>	MV Load and State Forecast
<b>4.</b>	MV Network Power Control
<b>5.</b>	Dynamic Monitoring for TSO
<b>6.</b>	Decentralized FLISR
<b>7.</b>	Microgrid FLISR
<b>8.</b>	Power Quality Control
<b>9.</b>	Protection Configuration Update
<b>10.</b>	Network Description Update

#### Secondary Substation Data eXchange Platform (SSDXP)

The SSDXP has the same feature, even though with different requirements in term of capacity of storage and number of channel, of that one installed in primary substation. It takes place in the following use cases:

<b>1.</b>	MV Real-Time Monitoring and LV Real-Time Monitoring
<b>2.</b>	Real-Time LV State Estimation
<b>3.</b>	LV Load and State Forecast
<b>4.</b>	LV Network Power Control and MV Network Power Control
<b>5.</b>	Dynamic Monitoring for TSO
<b>6.</b>	Protection Configuration Update
<b>7.</b>	Network Description Update
<b>8.</b>	Power Quality Control

#### Control Center Data eXchange Platform (CCDXP)

CCDXP has the same feature, even though with different requirements in term of capacity of storage and number of channel, of those ones installed in primary and secondary substation. It supports automation at the control center level and in general provides the DMS with the necessary information. It stores key information, like grid model, status of protection, customer information, and asset database. It takes place in the following use cases:

<b>1.</b>	Control Center Network Power Control
<b>2.</b>	Target network planning
<b>3.</b>	Expansion network planning

<b>4.</b>	Operational planning
<b>5.</b>	Load Areas Configuration
<b>6.</b>	Off-Line Validation
<b>7.</b>	Real-Time Validation
<b>8.</b>	Day-ahead demand response of the flexible demand
<b>9.</b>	Day ahead dynamic tariff (DADT)

#### Commercial aggregator Data eXchange Platform (CADXP)

CADXP has the same feature, even though with different requirements in term of capacity of storage and number of channel, of those ones installed in primary and secondary substation and at control center. It provides the commercial aggregator with the information needed to compute the optimal schedules of its load area. It takes place in the following use cases:

<b>1.</b>	Commercial aggregator asset planning
<b>2.</b>	Flexibility Table
<b>3.</b>	Day-Ahead Dynamic Tariff

#### Transmission System Operator (TSO)

It is a legal actor responsible for operating, ensuring the maintenance of and developing the transmission system in a country or a certain region the country. The TSO is often owned by the government and it's responsible for trading power with the neighbor countries. It takes place in the following use cases:

<b>1.</b>	Load areas configuration, where it assigns each DSOs' load area to a macro load area and communicates this information to the DSOs.
<b>2.</b>	Flexibility table, where it calculates Internal flexibility tables for macro load areas.
<b>3.</b>	Off-Line Validation (OLV), where it validates technical feasibility of the bids resulting from the market clearing process.
<b>4.</b>	Real-Time validation where the DSO validates the technical feasibility of the activation CRPs previously validated by the Off-Line Validation (OLV).
<b>5.</b>	Dynamic Monitoring for TSO

#### Distribution System Operator (DSO)

It is a legal actor responsible for operating, ensuring the maintenance of and, if necessary, developing the distribution system in a given area and, where applicable, its interconnections with other systems for

ensuring the long-term ability of the system to meet reasonable demands for the distribution of electricity. Moreover, the DSO is responsible for regional grid access and grid stability, integration of renewables at the distribution level and regional load balancing. Beside the management of the distribution network, it covers two roles: modeler and technical aggregator. As modeler, the DSO, extracts the data related to the model of the grid, customers and past reports of congestions, status of the grid and elaborates them in order to forecast congestions and price for electricity and flexibility; consequently, it prepares an optimum planning of investments for the grid. Regarding the role of technical aggregator, the DSO aggregates the prosumers in load areas and prepares flexibility tables, which inform about the flexibility availability of the DERs. It also validates the schedule coming from the market clearing program, both off line and in real time. The DSO takes place in the following UCs:

<b>1.</b>	Load areas configuration as technical aggregator.
<b>2.</b>	Flexibility table, as technical aggregator.
<b>3.</b>	SRP and CRP Day-Ahead and Intra-Day Market Procurement as technical aggregator.
<b>4.</b>	Target network planning, in terms of modeler, a person in charge of modeling the network.
<b>5.</b>	Expansion planning, where it provides information of financial state of the network company (current tariffs, operational costs, capital costs).
<b>6.</b>	Off-Line Validation (OLV), where the technical aggregator validates technical feasibility of the bids resulting from the market clearing process.
<b>7.</b>	Real Time Validation (RTV), where the technical aggregator validates the technical feasibility of the activation CRPs previously validated by the Off-Line Validation (OLV).

### Distribution Management System (DMS)

This actor acts as a decision support system to assist the control room and field operating personnel with the monitoring and control of the electric distribution system. It includes a collection of applications designed to monitor & control the entire distribution network efficiently and reliably. It takes place in the following UCs:

<b>1.</b>	MV Real-Time Monitoring and LV Real-Time Monitoring
<b>2.</b>	MV Load and State Forecast and LV Load and State Forecast
<b>3.</b>	Dynamic Monitoring for TSO
<b>4.</b>	Control Center Network Power Control
<b>5.</b>	Expansion planning UC

<b>6.</b>	Load Areas Configuration
<b>7.</b>	Day-Ahead Dynamic Tariff
<b>8.</b>	Day-Ahead Demand Response

### Commercial Aggregator (CA)

Also called flexibility suppliers, the CA receives forecasts for demand and DERs, regarding the load area which it has been assigned to. Forecasts and demand are available at the CADXP. The CA formulates the offers for flexibility services and energy production/consumption for its load areas, and then sends the offers to the market operator. Consequently, after receiving the schedules for the DERs, once the market clearing and validation phases have been completed, the CA forward the schedules to the corresponding DERs. The Aggregator presented here is in a draft form as it is not possible to define it in detail without further assumptions on the operation of the markets. The missing assumption and definitions for the Aggregator will be released later in the project in an add on to D3.1. WP3 will be responsible for collecting this information and preparing the document. The CA takes place in the following UCs:

<b>1.</b>	DADT
<b>2.</b>	Commercial aggregator asset planning
<b>3.</b>	Load areas configuration
<b>4.</b>	Off-Line Validation (OLV)
<b>5.</b>	Real Time Validation (RTV)
<b>6.</b>	CRP activation
<b>7.</b>	SRP and CRP Day-Ahead and Intra-Day Market Procurement

### Balance Responsible Party (BRP)

Also called flexibility buyers, it receives the bidding process before the gate opens for the day ahead and intra-day market. In between gate opening and gate closure of the market, flexibility bids are taken into consideration during the clearing phase (in any given market, volumes always adjust up or down such that quantity supplied equals the quantity demanded). Market clearing is the process of getting there via price adjustment). BRP and commercial aggregator will sign and submit flexibility bids to be considered during the market clearing phase. These bids should be sent during the gate opening period. One message will be sent for each load area for which the service is required or offered. It takes place in the following UCs:

<b>1.</b>	CRP activation
<b>2.</b>	SRP and CRP Day-Ahead and Intra-Day Market Procurement

### Market Operator (MO)

The MO matches all the bids in the market and decides the power traded by the commercial aggregator in each period of the next day. This information is sent to the aggregator and to the TSO and DSO. The MO determines the market energy price for the market balance area after applying technical constraints from

the system operator. It may also establish the price for the reconciliation within a metering grid area. This actor takes place in the following UCs:

<b>1.</b>	Commercial aggregator asset planning
<b>2.</b>	SRP and CRP Day-Ahead and Intra-Day Market Procurement
<b>3.</b>	Off-Line Validation
<b>4.</b>	Real-Time Validation

#### Weather Data Provider (WDP)

The WDP is a company which measures, forecast and sell information regarding sun irradiation, wind speed, temperature in several areas. It takes place in the following UC:

<b>1.</b>	Expansion planning
-----------	--------------------

#### Customer Information Service (CIS)

CIS is a system which stores and provides information about existing customers. It involves the use of technology to organize, automate and synchronize sales, marketing, customer service, and technical support. It takes place in the following UCs.

<b>1.</b>	Expansion planning
<b>2.</b>	Network description update

#### Network Information Service (NIS)

NIS is an IT System for information about existing network components and their location. It takes place in the following UCs:

<b>1.</b>	Expansion planning
<b>2.</b>	Network description update

#### Asset Management System (AMS)

AMS is a system for monitoring and maintenance for equipment, IT, information of the network. It takes place in the following UCs:

<b>1.</b>	Expansion planning
<b>2.</b>	Network description update

#### Geographic Information System (GIS)

GGIS is a system for collecting, storing, modification and analysis of geographic data regarding the distribution network. It takes place in the following UC:

<b>1.</b>	Network description update
-----------	----------------------------

### Home Energy Management System (HEMS)

This actor, which can have several nomenclatures such as producer or customer, represents the interface of the prosumer to the grid. It is the means for the person owning load/generation/storage power equipment to interact both with the property low voltage grid and the external world. HEMS can also provide measurements. Moreover, it represents the interface of the prosumer with the commercial aggregator (CA). It takes place in the following UCs:

<b>1.</b>	LV Real-Time Monitoring
<b>2.</b>	Network Description Update
<b>3.</b>	Load Areas Configuration
<b>4.</b>	Day-Ahead Dynamic Tariff

### *Mapping of Actors in Smart Grid Plane Zones and Domains*

As highlighted in Chapter 2, an important outcome of the Use Case Methodology is SGAM framework. For the concept of automation architecture, the SGAM allows the mapping of the actors (and functions later on) on to the Smart Grid Plane (Table 3.3), where the coordinates are the zones and domains previously defined.

**Table 3.3: Actors in IDE4L architecture mapped in the Zone and Domains of the Smart Grid Plane.**

	actors	Zone	Domain
<b>1.</b>	Distributed Intelligent Electronic Devices (DIEDs)	Field	Distribution DER
<b>2.</b>	Primary Substation Intelligent Electronic Devices (PSIEDs)	Station	Transmission Distribution
<b>3.</b>	Secondary Substation Intelligent Electronic Devices (SSIEDs)	Station	Distribution
<b>4.</b>	Primary Substation Automation unit (PSAU)	Station	Transmission Distribution
<b>5.</b>	Secondary Substation Automation Unit (SSAU)	Station	Distribution
<b>6.</b>	Microgrid central controller (MCC)	Operation	Distribution
<b>7.</b>	Primary Substation Data eXchange Platform	Station	Transmission Distribution

	(PSDXP)		
8.	Secondary Substation Data eXchange Platform (SSDXP)	Station	Distribution
9.	Control center Data exchange platform (DXP)	Operation	Distribution
10.	Commercial aggregator Data eXchange Platform (CADXP)	Enterprise	DER
11.	TSO	Enterprise	Transmission
12.	DSO	Enterprise	Distribution
13.	Distribution Management System (DMS)	Operation	Distribution
14.	Commercial Aggregator (CA)	Enterprise	DER
15.	Balance Responsible Party (BRP)	Market	Transmission Distribution
16.	Market operator (MO)	Market	Generation Transmission Distribution
17.	Weather data provider (WDP)	Enterprise	Distribution
18.	Customer information service (CIS)	Enterprise	DER Customer
19.	Network information service (NIS)	Enterprise	Distribution
20.	Asset management system (AMS)	Enterprise	Distribution
21.	Geographic information system (GIS)	Enterprise	Distribution
22.	Home Energy management system	Field	DER



### *Synthesis of functions*

Functions in IDE4L are compliant with the definition in [16]. They represent a block elaborating information coming from one or more actors, and providing it to one or more other actors. Functions are very different among the UCs but can be classified among some categories as shown in Table 3.4.

Table 3.4: Functions in IDE4L architecture.

Functions	
1.	Measurement acquisition (MA)
2.	Fault information acquisition (FIA)
3.	Protection configuration update (PCU)
4.	Network description update (NDU)
5.	Customer repository update (CRU)
6.	Network information acquisition (NIA)
7.	Customer information acquisition (CIA)
8.	Flexibility and DER status acquisition (FDA)
9.	estimate state (ES)
10.	Forecast state (FS)
11.	Data filtering (DF)
12.	Data Harmonization (DH)
13.	Data storage (DS)
14.	Data presentation (DP)
15.	Check status of electrical variables (CSEV)
16.	Control functions (CFs)
17.	Optimization model (OM)
18.	Compute control signals (SCSs)
19.	Compute schedule (SC)
20.	Fault processing (FP)
21.	Scheduling

22.	Bid submission (BS)
23.	Request/Reply Validation (RRV)
24.	Scenario forecasting (SF)
25.	Network design (ND)
26.	Expansion scheduling process (ESP)
27.	Load area configuration (LAC)
28.	Flexibility tables (FTs)
29.	Market clearing (MC)
30.	Conditional Re-Profiling (CRP)
31.	Day ahead tariffs (DAT)

### Measurement Acquisition (MA)

This function includes the acquisition of data message in several protocols and the interface to database tables in the DXPs. It represents the collection of measurements in different protocols, in particular MMS, GOOSE, SV protocols (from the standard IEC61850) and IEC101, IEC104, modbus and IEC103 for substation IEDs, the DLMS/COSEM protocol for the communication with electronic meters (EM) and the C37.118.1-2011 and IEC 61850-90-5 for PMUs. In the next level of description of the architecture, this function can be further developed with higher level of details, e.g. reporting rate, protocols and hence be split in several functions. It takes place in the following UCs:

1.	MV Real-Time Monitoring and LV Real-Time Monitoring
2.	Dynamic Monitoring for TSO
3.	Microgrid FLISR

### Fault Information Acquisition (FIA)

FIA is a function representing the acquisition of fault related data, as faulted phases, power flow direction, fault currents, etc. relatively to their positions, from IEDs. With the FIA function, the decentralized IEDs controlling switches will communicate, among them and with the PSAU, the fault related information, allowing determining a more precise faulted section area, thus reducing the isolated area. The difference with respect of the MA function is that it represents the acquisition of high priority information with respect to measurements. The FIA function is exploited by IEDs, PSAUs, DXPs (for fault related data storage) and Micro grid central controller. It takes place in the following UCs:

1.	Decentralized FLISR
2.	Microgrid FLISR

### Protection Configuration Update (PCU)

When the PSAU detects a network configuration update, it starts the update process sending the new parameters values to the protection devices (IEDs) and the DXP. IEDs that receive the update request parse it and write their new parameters values according with the PSAU notification. It takes place in the following UC:

- |  |  |
|--|--|
|  | 1. In Protection configuration update UC |
|--|--|

### Network Description Update (NDU)

This function describes how the DMS updates the information of the grid with the network description update (NDU) function after it has been informed by a customer or network change with the function NIA. It takes place in the following UC:

- |  |  |
|--|--|
|  | 1. Network description update Use case |
|--|--|

### Customer Repository Update (CRU)

This function describes how the DMS updates the information of the customers (here intended more generally as prosumers) with the Customer repository update (CRU) function after it has been informed of a customer change with the function CIA. It takes place in the following UC:

- |  |  |
|--|--|
|  | 1. Network description update Use case |
|--|--|

### Network Information Acquisition (NIA)

NIA represents a function which allows the DMS to be informed about some network change and collect the updated information in order to reformulate the model of the network which is managing. It clusters to type of similar functions: respectively the advice for network change and the collection of updated information. The actors providing the information about the changes in the network are NIS, AMS and GIS. It takes place in the following UCs:

- |  |  |
|--|--|
|  | 1. Network description update Use case |
|  | 2. Target network planning             |

### Customer Information Acquisition (CIA)

The updated list of customer contracts is provided by the Customer information system (CIS) and the Home energy management systems (HEMSs). It takes place in the following UCs:

- |  |  |
|--|--|
|  | 1. Network description update Use case |
|  | 2. Expansion planning                  |

### Flexibility and DER Status Acquisition (FDA)

It indicates the acquisition of the DER status and the flexibility disposability from the prosumer, through the HEMSs. The information is communicated and stored at the control center DXP. It takes places in the following UC:

<b>1.</b>	Load Areas (Las) configuration
-----------	--------------------------------

### Estimate State (ES)

It represents a set of functions which provide the state of the system at actual time. It takes place in the following UC:

<b>1.</b>	Real-Time MV State Estimation and Real-Time LV State Estimation
-----------	---

### Forecast State (FS)

It represents a set of functions which provide the state of the system in the future. It takes place in the following UC:

<b>1.</b>	MV Load and State Forecast and LV Load and State Forecast
-----------	---

### Data Filtering (DF)

This set includes the algorithms used to filter data in order to store/send only meaningful and correct information. Some of the measurement may have to be processed, through some filters against bad data, in some dedicated functions which have been clustered under the name Data filtering (DF). It takes place in the following UCs:

<b>1.</b>	It represents the filter for data verification and to process the erroneous measurements in Real-Time MV State Estimation, Real-Time LV State Estimation, MV Load and State Forecast and LV Load and State Forecast.
<b>2.</b>	It represents the function “Dynamic info derivation” in Dynamic Monitoring for TSO.
<b>3.</b>	It represents the function “Bad data handling” in Dynamic monitoring for TSO use case.

### Data Harmonization (DH)

This function represents the harmonization between measurements with different reporting rates. It takes place in the following UCs:

<b>1.</b>	LV Real-Time Monitoring and MV Real-Time Monitoring
<b>2.</b>	Dynamic Monitoring for TSO

### Data Storage (DS)

In this function data from multiple devices are ordered in time and stored. DS function is intended to represent both the process of storage and extraction of data from database. It takes place in the following UCs:

<b>1.</b>	MV Real-Time Monitoring and LV Real-Time Monitoring
-----------	---

<b>2.</b>	Real-Time MV State Estimation and Real-Time LV State Estimation
<b>3.</b>	MV Load and State Forecast and LV Load and State Forecast
<b>4.</b>	Dynamic Monitoring for TSO
<b>5.</b>	Network Description Update
<b>6.</b>	Protection Configuration Update
<b>7.</b>	Control center power control
<b>8.</b>	MV Network Power Control and LV Network Power Control
<b>9.</b>	Control Center Network Power Control
<b>10.</b>	Power quality (PQ) in LV/MV lines with power electronic-based systems
<b>11.</b>	Decentralized FLISR
<b>12.</b>	Microgrid FLISR
<b>13.</b>	Power Quality Control
<b>14.</b>	Target Network Planning
<b>15.</b>	Expansion Planning
<b>16.</b>	Operational Planning
<b>17.</b>	Off-Line Validation
<b>18.</b>	Real-Time Validation
<b>19.</b>	Day ahead dynamic tariff
<b>20.</b>	Day ahead demand response

### Data Presentation (DP)

With this function, the meaningful, synthetized and averaged data are presented in a graphical user interface to the operators in the control center. The function data presentation (DP) regards the mathematical computation done in order to make the available data suitable for visual representation to operators. The monitoring system located in primary and secondary substation should be able to expose to the upper level, mainly for the DMS located in primary substation, the stored data. It takes place in the following UCs:

<b>1.</b>	Real-Time Low and Medium Voltage Monitoring
<b>2.</b>	Dynamic Monitoring for TSO

### Check Status of Electrical Variables (CSEV)

This function represents the process of checking the state of the grid against the grid model. Voltages and power flow are the parameters to be usually checked. Reference data should be within the security ranges for the buses and branches of the grid. It receives such an input from the DXP. It takes place in the following UCs:

<b>1.</b>	Low voltage power control and Medium voltage power control
<b>2.</b>	Control center power control
<b>3.</b>	Power quality (PQ) control
<b>4.</b>	Off-Line Validation
<b>5.</b>	Real-time Validation
<b>6.</b>	Microgrid FLISR
<b>7.</b>	Operational planning

### Compute Control Signals (SCSs)

The control actions are elaborated and mapped in industrial protocols, in order to be sent to the IEDs in terms of control signals, with the function “compute control signals”. Under this group are clustered several types of control signals like new topologies, tap changer settings, flexible DERs’ commands. It takes place in the following UCs:

<b>1.</b>	Low voltage power control and Medium voltage power control
<b>2.</b>	Control center power control
<b>3.</b>	Microgrid FLISR
<b>4.</b>	Power quality (PQ) control

### Compute Schedule (CS)

It represents the cluster of functions which regards the computation of active and reactive power schedule, for technical and commercial aggregators and for HEMSS. In day-ahead dynamic tariff use case the schedule for power injection of prosumers is sent from aggregators to HEMS. In validation use cases the schedule is sent from TSO and technical aggregators to commercial aggregator. This function takes place in the following UCs:

<b>1.</b>	Commercial aggregator asset planning
<b>2.</b>	Conditional re-profiling activation (CRP Activation)
<b>3.</b>	Off-Line Validation
<b>4.</b>	Real-Time Validation

	5. Day-Ahead Dynamic Tariff
--	-----------------------------

### Fault Processing (FP)

Fault processing (FP) function indicates the peer to peer communication between IEDs located within the area affected by the fault, as well as with the PSAU. The information received will be processed by each IED in order to determine the circuit breaker opening action closest to the location of the fault. FP includes also the peer communication among IEDs during the service restoration phase, in order to minimize the outage cost. It takes place in the following UC:

	1. Decentralized FLISR
--	------------------------

### Control Functions (CFs)

These functions include all the algorithms needed to bring the system in security ranges, whenever congestion is detected. After an iterative process where an acceptable solution to congestion is found, the control actions are sent to local DXPs, PSAU, SSAU, and DMS and converted through the function compute control signals in control signals for the IEDs. It takes place in the following UCs:

	1. Power quality in LV/MV lines with power electronic-based systems
	2. LVPC and MVPC
	3. CCPC
	4. Microgrid FLISR
	5. Off-Line Validation
	6. Real-time Validation

### Optimization Model (OM)

The function OM receives data are energy demands and comfort requirements of the customers as inputs. The availability of the flexible demands is included as constraints and the cost is the objective function, which is provided as output. It takes place in the following UC:

	1. Day ahead demand response of the flexible demand
--	---

### Bid Request (BR)

With this function the Market Operator sends the request for bid to both Balance Responsible Parties and Commercial Aggregators. It takes place in the following UC:

	1. SRP and CRP Day-Ahead and Intra-Day Market Procurement
--	---

### Bid Submission (BS)

With this function the aggregator submits a bid to the market operator. It takes place in the following UCs:

<b>1.</b>	Commercial aggregator asset planning
<b>2.</b>	SRP and CRP Day-Ahead and Intra-Day Market Procurement

### Request/Reply Validation (RRV)

It indicates the function with which DSOs and TSOs receive the request from market operators to validate a certain schedule. DSOs and TSOs then operate some power flow analysis and reply with the same function. It takes place in the following UCs:

<b>1.</b>	Off-Line Validation
<b>2.</b>	Real-time Validation

### Scenario Forecasting (SF)

DER scenarios are evaluated by the DSO, with the function Scenario forecasting and stored in DXP with the function DS. It takes place in the following UCs:

<b>1.</b>	Expansion planning
-----------	--------------------

### Network Design (ND)

The goal of this function is to plan the topology and structure of the network based on economic, technical and geographic restrictions. This function determines the optimal placement of transformers, cables and output the dimension of these components. It takes place in the following UC:

<b>1.</b>	Target network planning
-----------	-------------------------

### Expansion Scheduling Process (ESP)

With this function DSO in the role of the “Expansion network planner” calculates the optimal sequence of development steps to reach target network plans. It takes place in the following UC:

<b>1.</b>	Expansion planning
-----------	--------------------

### Load Area Configuration (LAC)

The same type of function is used by TSOs to assigns each DSOs' load area to a macro load area, and by each DSO to assign each prosumer to a load area. It takes place in the following UC:

<b>1.</b>	Load area configuration
-----------	-------------------------

### Flexibility Tables (FTs)

The same type of function is used by TSOs to calculate the flexibility tables for macro load areas and by DSOs to calculate flexibility tables for load areas. It takes place in the following UC:

<b>1.</b>	Flexibility tables
-----------	--------------------

## Market Clearing (MC)

With this function the Market Operator assures that demand = offer. It takes place in the following UC:

1.	SRP and CRP Day-Ahead and Intra-Day Market Procurement
----	--

## Conditional Re-Profilng (CRP)

With this function a flexibility buyer (BRP, DSO, and TSO) activates a previously settled CRP product for balancing and/or congestion management proposes. It takes place in the following UC:

1.	Conditional re-profiling activation (CRP Activation)
----	--

## Day ahead tariffs (DAT)

With this function the DMS determines the day-ahead tariffs for the distribution network to alleviate congestion with the DAT function. It takes place in the following UC:

1.	Day ahead dynamic tariff
----	--------------------------

## *Mapping of functions in zones and domains*

Table 3.5 shows how the IDE4L functions are mapped onto the smart grid plane.

**Table 3.5: Functions in IDE4L architecture mapped in the Zone and Domains of the Smart Grid Plane.**

	Functions	Zone	Domain
1.	Measurement acquisition (MA)	Field Station	Distribution
2.	Fault information acquisition (FIA)	Field Station	Distribution
3.	Protection configuration update (PCU)	Station	Distribution
4.	Network description update (NDU)	Station	Distribution
5.	Customer repository update (CRU)	Station	DER Customer
6.	Network information acquisition (NIA)	Station	Distribution
7.	Customer information acquisition (CIA)	Station	DER Customer

8.	Flexibility and DER status acquisition (FDA)	Station	DER
9.	Estimate state (ES)	Station	Distribution
10.	Forecast state (FS)	Station	Distribution
11.	Data filtering (DF)	Station	Distribution
12.	Data harmonization (DH)	Station	Distribution
13.	Data storage (DS)	Station	Distribution
14.	Data presentation (DP)	Station	Distribution
15.	Check status of electrical variables (CSEV)	Station Operation	Distribution
16.	Compute control signals (SCSs)	Operation	Distribution
17.	Compute schedule (SS)	market	DER
18.	Fault processing (FP)	Station Field	Distribution
19. 18	Control functions (CFs)	Operation	Distribution DER
20.	Optimization model (OM)	Operation	DER
21.	Bid request (BR)	Market	Distribution DER
22.	Bid submission (BS)	Market	Distribution DER
23.	Reply/request validation (RRV)	Market	Transmission Distribution
24.	Scenario forecasting (SF)	Enterprise	DER
25.	Network design (ND)	Enterprise	Distribution
26.	Expansion scheduling process (ESP)	Enterprise	Distribution

27.	Load area configuration (LAC)	Market	Distribution Transmission
28.	Flexibility tables (FTs)	Operation	DER
29.	Market clearing (MC)	Market	Distribution
30.	Conditional Re-Profiling (CRP)	Market	Distribution DER
31.	Day ahead tariffs (DATs)	Market	DER

### ***Connections between Actors and Functions***

The last important outcome of the phase of synthesis and harmonization of use cases is the generation of the list and description of connections between actors and functions. At the concept level of description of the architecture, the content of such information exchange and initial and final destination are described.

#### **Measurements from devices**

Distributed measurement devices, such as advanced metering infrastructure (AMI) devices, Remote terminal units (RTUs), phasor measurement units (PMUs) and Intelligent electronic devices (IEDs), that have been clustered in three groups under the names DIED, PSIED, SSIED, provide measurements with different protocols, reporting rate and physical medium to the data exchange platforms in substation environment. The actors who manage this exchange of information are:

- |    |   |
|----|---|
| 1. | Distributed intelligent electronic devices (DIED)           |
| 2. | Primary substation intelligent electronic devices (PSIED)   |
| 3. | Secondary substation intelligent electronic devices (SSIED) |
| 4. | Secondary substation data exchange platform Data (SSDXP)    |
| 5. | Primary substation data exchange platform (PSDXP)           |

#### **Data handling and elaboration in DXP**

It includes the data flow within DXP layers, namely interface, application and storage layers, for filtering, harmonization and storing into database. It involves the following actors:

- |    |  |
|----|--|
| 1. | Secondary substation data exchange platform Data (SSDXP) |
| 2. | Primary substation data exchange platform (PSDXP)        |
| 3. | Control center data exchange platform (CCDXP)            |

### Data handling and elaboration for control actions

It includes the flow of data among PSAU, SSAU and DXP, as well as between DMS and CC DXP. Current states and grid model data are furnished in order to allow PSAU, SSAU and DMS to verify the state of the portion of grid under its control. It is needed to perform forecast and state estimation algorithms, as well as for checking the state of the system versus grid limit, such as voltage and maximum current constraints. It involves the following actors:

<b>1.</b>	Secondary substation data exchange platform Data (SSDXP)
<b>2.</b>	Primary substation data exchange platform (PSDXP)
<b>3.</b>	Control center data exchange platform (CCDXP)
<b>4.</b>	Primary substation automation unit (PSAU)
<b>5.</b>	Secondary substation automation unit (PSAU)
<b>6.</b>	Distribution management system (DMS)

### Updates of database information

It represents the update of network model, in terms of parameters and topology, status of protections, customer descriptions and status of controllers (e.g. OLTCs, PV inverters etc). The information exchange takes place among PSAU, SSAU and DMS and local DXPs in case of control actions, faults, and network or customer changes. It involves the following actors:

<b>1.</b>	Secondary substation data exchange platform Data (SSDXP)
<b>2.</b>	Primary substation data exchange platform (PSDXP)
<b>3.</b>	Control center data exchange platform (CCDXP)
<b>4.</b>	Primary substation automation unit (PSAU)
<b>5.</b>	Secondary substation automation unit (PSAU)
<b>6.</b>	Distribution management system (DMS)

### Data handling for presentation in HMI

Data regarding the status of the grid are retrieved by DMS from substation and control center in order to elaborate and synthetize them for an effective visual representation for the operators in the control center. It involves the following actors:

<b>1.</b>	Secondary substation data exchange platform Data (SSDXP)
<b>2.</b>	Primary substation data exchange platform (PSDXP)

- |           |   |
|-----------|---|
| <b>3.</b> | Control center data exchange platform (CCDXP) |
| <b>4.</b> | Distribution management system (DMS)          |

### Customer information updates

An update is required when a new customer is connected to the grid or when he/she changes type of contract. The information is encapsulated in a CIM message and sent from the Home energy management system (HEMS) to the DMS, which updates the customer repository, also furnished by the customer information service (CIS) with a CIM message. It involves the following actors:

- |           |                                      |
|-----------|--------------------------------------|
| <b>1.</b> | Distribution management system (DMS) |
| <b>2.</b> | Home energy management system (HEMS) |
| <b>3.</b> | customer information service (CIS)   |

### Network information updates

An update is required when a change happens in the network state, in terms of topology or parameters of the lines. The updates are communicated from Network information service (NIS), Geographic information system (GIS) and Asset management system (AMS) to the DMS, which updates the network information. It involves the following actors:

- |           |                                      |
|-----------|--------------------------------------|
| <b>1.</b> | Distribution management system (DMS) |
| <b>2.</b> | Network information service (NIS)    |
| <b>3.</b> | Geographic information system (GIS)  |
| <b>4.</b> | Asset management system (AMS)        |

### Updates of protection configuration

PSAUs and SSAUs update the parameters of the protection devices to local DXPs and IEDs. It involves the following actors:

- |           |   |
|-----------|---|
| <b>1.</b> | Secondary substation data exchange platform Data (SSDXP)  |
| <b>2.</b> | Primary substation data exchange platform (PSDXP)         |
| <b>3.</b> | Primary substation automation unit (PSAU)                 |
| <b>4.</b> | Secondary substation automation unit (SSAU)               |
| <b>5.</b> | Distributed intelligent electronic devices (DIED)         |
| <b>6.</b> | Primary substation intelligent electronic devices (PSIED) |
| <b>7.</b> | Secondary substation intelligent electronic devices       |

	(SSIED)
--	---------

### Control signals to IEDs

PSAUs, SSAUs, Microgrid central controllers (MCCs) and DMSs compute control signals to IEDs. It generally represents the set point for the controller, in numerical or analog forms. It involves the following actors:

1.	Primary substation automation unit (PSAU)
2.	Secondary substation automation unit (SSAU)
3.	Distributed intelligent electronic devices (DIED)
4.	Primary substation intelligent electronic devices (PSIED)
5.	Secondary substation intelligent electronic devices (SSIED)
6.	Microgrid central controller (MCC)
7.	Distribution management system (DMS)

### Fault information acquisition

The IEDs communicate, among them and with the MCCs and PSAU, the fault related information, as faulted phases, power flow direction, fault currents, etc. relative to their positions, allowing determining a more precise faulted section area, in order to isolate the faulted area and then perform a reconfiguration of the network. It involves the following actors:

1.	Primary substation automation unit (PSAU)
2.	Microgrid central controller (MCC)
3.	Distributed intelligent electronic devices (DIED)
4.	Primary substation intelligent electronic devices (PSIED)
5.	Secondary substation intelligent electronic devices (SSIED)

### Acquisition of status of the grid and forecasts and market information by commercial aggregator

The Commercial aggregators (CAs) receive information about its customers (size, flexibility, storage capability) and forecasts for their production and demand from the local DXPs. Furthermore it acquires the grid model and current status. It involves the following actors:

1.	Secondary substation data exchange platform Data (SSDXP)
2.	Primary substation data exchange platform (PSDXP)

- |    |   |
|----|---|
| 3. | Control center data exchange platform (CCDXP) |
| 4. | Commercial aggregator                         |

#### Communication of bid request and submissions

The market operator sends to Balance responsible parties (BRPs) and commercial aggregators (CAs) the request for flexibility services. BRPs and CAs send Bids, containing flexibility services, to the Market operator. It involves, hence, the following actors:

- |    |                                    |
|----|------------------------------------|
| 1. | Transmission system operator (TSO) |
| 2. | Distribution system operator (DSO) |
| 3. | Commercial aggregator              |

#### Communication of market related information among TSOs, DSOs, and CAs

TSOs assign DSOs' load area to a macro load area and communicate this information to the DSOs. DSOs assign each prosumer to a load area and communicate this information to the commercial aggregators. On the same scheme the TSOs send flexibility tables to DSOs and DSOs calculate and send flexibility tables for load areas to the commercial aggregators before each bidding process. It involves the following actors:

- |    |                                    |
|----|------------------------------------|
| 1. | Transmission system operator (TSO) |
| 2. | Distribution system operator (DSO) |
| 3. | Commercial aggregator (CA)         |

#### Communication of market clearing prices to Balance responsible parties and commercial aggregators

The market operator communicates the market clearing price is communicated to BRPs and CAs. It consequently involves the following actors:

- |    |                                  |
|----|----------------------------------|
| 1. | Balance responsible party (BRPs) |
| 2. | Market operator (MO)             |
| 3. | Commercial aggregator (CA)       |

#### Communication for activation of conditional re-profiling

A flexibility buyer (BRP, DSO, TSO) identifies the need to activate a previously settled CRP product for balancing and/or congestion management proposes. It will send a schedule with the product to be activated to the aggregator. It consequently involves the following actors:

- |    |                                    |
|----|------------------------------------|
| 1. | Balance responsible party (BRPs)   |
| 2. | Transmission system operator (TSO) |
| 3. | Distribution system operator (DSO) |

<b>4.</b>	Market operator (MO)
<b>5.</b>	Commercial aggregator (CA)

### Communication of requests and replies of validation for activation

The balance responsible parties send a request for validation of the technical feasibility of the bids resulting from the market clearing process to TSOs and DSOs. It is used for Day-Ahead and Intra-day Market Validation. It consequently involves the following actors:

<b>1.</b>	Balance responsible party (BRPs)
<b>2.</b>	Transmission system operator (TSO)
<b>3.</b>	Distribution system operator (DSO)

### 3.1.5 Summary

This section the concept of the architecture was presented by providing use case descriptions. The IDE4L use cases have been presented exploiting a hierarchical presentation, starting from clusters, going to HLUCs and PUCs. By following this approach, the reader should have gained a growing understanding of IDE4L automation architecture functionalities as the description moves from high to lower level of abstraction. Consequently, the actors, functions and information exchanges required to satisfy such functionalities were presented, described and mapped in the proposed architecture (smart grid plane's zones and domains). Next sections describe the starting point architecture and incremental approach from the chosen starting point architectures, respectively.

## 3.2 Starting Point Architecture – INTEGRIS + ADDRESS

This section describes the chosen starting point architecture, which is the result of addition of two architectures, i.e. INTEGRIS [4] and ADDRESS [3], from a conceptual point of view. What we mean with the expression “from a conceptual point of view” is the extraction of actors, functions and links from the INTEGRIS and ADDRESS use cases to be brought to the same level of the IDE4L use cases so that the incremental approach described in the next section can be enabled to define the IDE4L automation concept.

### 3.2.1 INTEGRIS Use Cases

For the INTEGRIS architecture, the UCs are collected in a consolidated document [24] and fully described in Annex 7. Table 3.6 and Table 3.7 list the INTEGRIS actors and functions, respectively. It should be noticed that actors and functions reflects the actual architecture implementation (refer to Annex 7 for detailed descriptions of actors and functions).

Table 3.6: Actors in INTEGRIS architecture.

	actors
<b>1.</b>	PQ – Power Quality Meter
<b>2.</b>	HGW – Home Gateway
<b>3.</b>	RTU – Remote Terminal Unit

4.	SM – Smart Meter
5.	MDC – Meter Data Collector
6.	PC:UDC – User Data Collector (in the PC)
7.	PC:RTUDC – RTU Data Collector (in the PC)
8.	PC:MV/LV – MV/LV Data Handler (in the PC)
9.	PGW – Protocol Gateway
10.	PC:ICF – INTEGRIS Communication Functionality (in the PC)
11.	PC:SE – State Estimator algorithm (in the PC)
12.	PC:MPFV – Manage Power Flows and Voltage algorithm (in the PC)
13.	PC:FM – Fault Manager (in the PC)
14.	HGW:AC
15.	DM – DER Meter
16.	PC:DB – Data Base (in the PC)
17.	SCADA
18.	DER
19.	DG

**Table 3.7: Functions in INTEGRIS architecture.**

	functions
1.	Data collection
2.	Data encapsulation
3.	Averaged measurements
4.	Data “intermediate” collection
5.	PQ measurements
6.	RTU data collection
7.	Measuring
8.	Connection establishment
9.	Report of measured values

<b>10.</b>	Reporting alarms
<b>11.</b>	Data Acquisition for SE
<b>12.</b>	SE Algorithm
<b>13.</b>	MPFV Algorithm
<b>14.</b>	Substation Command Transfer
<b>15.</b>	Command/Acknowledge Transfer
<b>16.</b>	DER Control
<b>17.</b>	Data of the fault
<b>18.</b>	Info of faulty area
<b>19.</b>	Fault monitoring
<b>20.</b>	Switch control
<b>21.</b>	DG control
<b>22.</b>	Reasons for fault

### 3.2.2 ADDRESS Use Cases

For the ADDRESS architecture, the UCs of interest are described in Deliverables 1.1 and 4.1 [3] and fully described in Annex 8. Table 3.8 and Table 3.9 list the ADDRESS actors and functions, respectively. Refer to Annex 8 for detailed descriptions of actors and functions.

Table 3.8: Actors in ADDRESS architecture.

	actors
<b>1.</b>	Aggregator
<b>2.</b>	Consumer
<b>3.</b>	DSO
<b>4.</b>	TSO
<b>5.</b>	AD Buyers
<b>6.</b>	Market Operator

Table 3.9: Functions in ADDRESS architecture.

	functions
<b>1.</b>	Macro load area configuration

2.	Assignment each consumer to a load area
3.	Flexibility table calculation (TSO perspective)
4.	Flexibility table calculation (DSO perspective)
5.	AD product bidding process
6.	Market clearing
7.	Technical validation reporting
8.	AD schedule reporting
9.	Technical feasibility evaluation
10.	CRP AD product activation

### 3.3 Incremental Approach for the Definition of the Automation Architecture Concept

#### 3.3.1 Incremental approach at Cluster level

Starting point architecture is INTEGRIS+ADDRESS, in particular

- Monitoring and Control use cases come from INTEGRIS
- Business use cases come from ADDRESS

Figure 3.4 shows the number of HLUCs coming from existing projects (INTEGRIS and ADDRESS) and number of new HLUCs developed in IDE4L as explained in Section 3.1 which the IDE4L Clustered Use Cases are composed by. The figure is meant to show the new concepts of the automation architecture to be developed for active distribution network management that the IDE4L project introduces with respect to the existing concepts already presented in the architectures chosen as starting point architectures. In particular, the IDE4L automation architecture concept is composed by 33% of INTEGRIS in the Monitoring cluster, 50% of INTEGRIS in the Control cluster, and 66% of ADDRESS in the Business cluster.

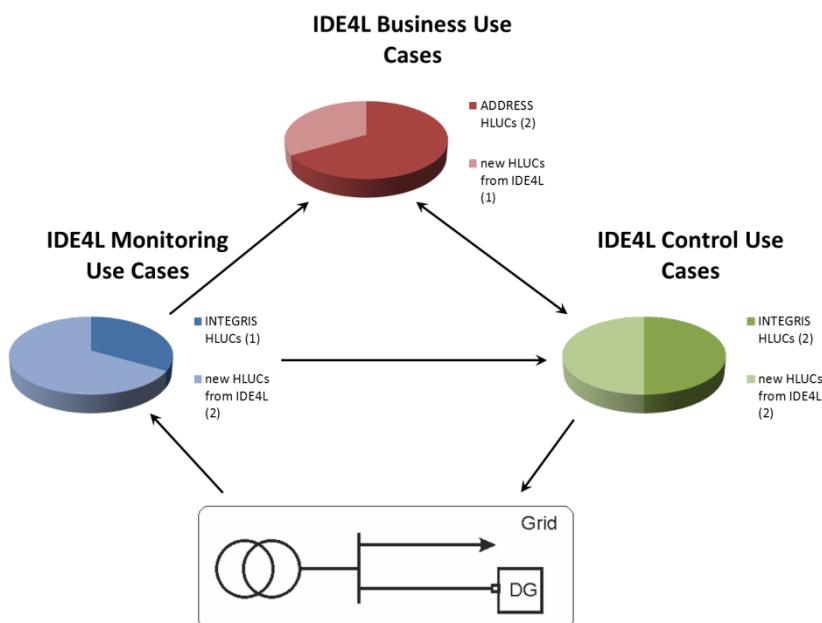


Figure 3.4: IDE4L Clustered Use Cases composed by HLUCs coming from existing projects and new HLUCs developed in IDE4L.

### 3.3.2 Incremental approach at High-Level Use Case level

Table 3.10 shows the HLUCs within the Monitoring and Control clusters for INTEGRIS and IDE4L. The table highlights the HLUCs which are (conceptually) identical to those in INTEGRIS and the “brand-new” HLUCs developed in IDE4L. New functionalities present in IDE4L, but not in INTEGRIS, are the Forecasting and the System Updating use cases for the Monitoring cluster, and the Power Quality Control and Network Planning use cases for the Control cluster. The Real-Time Monitoring in the Monitoring cluster, and the Power Control and FLISR use cases in the Control cluster, is conceptually identical to those ones in INTEGRIS.

Differences will be presented when performing the analysis at the Primary use case level.

Table 3.10: INTEGRIS vs. IDE4L HLUCs for the Monitoring and Control clusters.

UC Clusters	INTEGRIS HLUCs	IDE4L HLUCs
Monitoring	Real-Time Monitoring	Real-Time Monitoring
		Forecasting
		System Updating
Control	Power Control	Power Control
	FLISR	FLISR
		Power Quality
		Network Planning

Table 3.11 shows the HLUCs within the Business cluster for ADDRESS and IDE4L. The table highlights the HLUCs which are (conceptually) identical to those in INTEGRIS and the “brand-new” HLUCs developed in IDE4L. A new functionality present in IDE4L, but not in ADDRESS, is the Grid Tariffs use case, while the Aggr./DSO/TSO Interaction – both Operation and Market domains – are conceptually identical to those ones in ADDRESS. Once again, differences will be presented when performing the analysis at the Primary use case level.

Table 3.11: ADDRESS vs. IDE4L HLUCs for the Business cluster.

UC Clusters	ADDRESS HLUCs	IDE4L HLUCs
Business	Aggr./DSO/TSO Interaction – Operation Domain	Aggr./DSO/TSO Interaction – Operation Domain
	Aggr./DSO/TSO Interaction – Market Domain	Aggr./DSO/TSO Interaction – Market Domain
		Grid Tariffs

### 3.3.3 Incremental approach at primary use cases level – Automation architecture concept comparison IDE4L vs INTEGRIS

#### *Primary use cases*

First, a comparison is conducted among primary use cases, identifying different functionalities that have been activated in IDE4L with respect to INTEGRIS (Table 3.12).

Table 3.12: INTEGRIS vs. IDE4L PUCs.

INTEGRIS PUCs	IDE4L PUCs	General differences and comments
LV01 and LV02 monitoring (LV network monitoring)	low voltage real time monitoring	INTEGRIS use cases cover the collection of data from distributed measurement devices, in particular smart meters, DER meters and Home gateways, to the substation PC. In IDE4L also feeder and substation devices are taken into consideration.
MV03 monitoring (MV/LV substation monitoring)	low voltage real time monitoring	INTEGRIS use cases cover the collection of data from low voltage feeders and secondary substation. IDE4L use cases consider also the collection of data from Home energy management systems and other distributed Intelligent electronic devices.
LV01+LV02+MV03 (reporting MV/LV substation and LV measures to SCADA)	low voltage real time monitoring + medium voltage real time monitoring	In both IDE4L use cases the presentation of data to control center is included.
LV04 Manage power flows and voltage	Real Time Low voltage state estimation + Low voltage Network power	In IDE4L, the acquisition of data and the calculation of network states are presented in dedicated state estimation use cases. Similarly, a use case has been dedicated for power control in low voltage networks.

	control	
LV05 Manage fault	Decentralized FLISR	In IDE4L the fault is located and isolated through a horizontal peer-to-peer communication. The primary substation automation unit does not behave as central intelligence, but allows to have an overview of the problem, and to set a modification the faulted area. After that, the IEDs start the service restoration phase. In INTEGRIS the fault information is sent from the Home gateways to the User data collector in secondary substation, consequently, the alarms are generated by UDC and sent to SCADA for FLISR (centralized approach).

### New primary use cases from IDE4L

In IDE4L project, the clusters of Monitoring and Control use cases have been enlarged in order to fulfill better the requirements for distribution smart grid automation. The following primary use cases have been added (for their description check the primary use case section):

- Medium voltage load and state forecast represents the forecast algorithm for voltage and power injection in MV grid.
- Low voltage load and state forecast shows the forecast algorithm for voltage and power injection in LV grid.
- Dynamic monitoring for TSO implementing a particular functionality of the monitoring system, in order to send dynamic critical signals to TSO.
- Network description update addresses the requirement for system model update.
- Protection configuration update addresses the requirement for IEDs protection configuration update.
- Medium voltage network power control represents the control actions taken at primary substation level over the MV grid.
- Control center Network power control represents coordinated control actions taken at DMS level over the distribution grid.
- Microgrid FLISR represents the set of rules for management of a microgrid in case of contingencies in the main grid.
- Power quality control contains the control of the system in order to minimize power quality issues.
- Target network planning designs network structure with minimal costs for a given future generation and demand scenario.
- Expansion planning determines the proper development steps from one given distribution network structure to a target network.

### Actors

Now, a comparison is conducted among actors for the IDE4L architecture with respect to INTEGRIS (Table 3.13).

Table 3.13: INTEGRIS vs. IDE4L actors.

INTEGRIS actors	IDE4L actors	General differences and comments
DER meter (DM)	DIED	Distributed IEDs include DERs' meters.
Power Quality Meter (PQM)	DIED	Distributed IEDs include power quality meters.
Home Gateway (HGW)	HEMS	Home gateway is considered as Home energy management systems.
Smart Meter (SM)	DIED	Distributed IEDs include smart meters.
Meter Data Collector (MDC)	SSDXP	Meter data collector functionalities are included in the secondary substation data exchange platform.
User Data Collector in secondary substation PC (PC:UDC)	SSAU	Collection of data from database is managed by secondary substation automation unit.
Database in secondary substation PC (PC:DB)	SSDXP	Data exchange platform in secondary substation includes a database.
Protocol gateway (PGW)	SSDXP	The interface layer is part of the SSDXP.
RTU data Collector (PC:RTUDC)	SSDXP	The interface layer is part of the SSDXP.
Remote terminal unit (RTU)	SSIED	Secondary substation measurement devices go under the class SSIED.

SCADA	DMS	SCADA functionalities are included in the DMS.
MV/LV Data Handler (PC: MV/LV)	SSDXP	The interface layer, part of the SSDXP, covers also the conversion of database format into message format for transmission to DMS.
State estimation algorithm (PC: SE)	SSAU	State estimation functionalities are implemented in the secondary substation automation unit.
Manage power flow and voltage algorithm (PC: MPFV)	SSAU,	Power flow and voltage control algorithms are implemented in the secondary substation automation unit.
Switch	DIEDs	Distributed IEDs include switches.
PC:FM	SSAU	The SSAU manage the information about faults coming from DIEDs and SSIEDs.

### New actors from IDE4L

As far as IDE4L vs. INTEGRIS actor's comparison, the IDE4L architecture proposes new actors:

- Primary substation IED (PSIED)
- Primary substation DXP (PSDXP)
- Primary substation automation unit (PSAU)
- Control center DXP (CCDXP)
- Microgrid central controller (MCC)
- Transmission system operator (TSO)
- Distribution system operator (DSO)
- Commercial aggregator
- Customer information service (CIS)
- Network information system (NIS)
- Asset management system (AMS)
- Geographic information system (GIS)
- Weather data provider (WDP)

### Functions

A comparison is here conducted among functions for the IDE4L architecture with respect to INTEGRIS (Table 3.14).

Table 3.14: INTEGRIS vs. IDE4L functions.

INTEGRIS functions	IDE4L functions	General differences and comments
Data collection	Data storage	The INTEGRIS function defines the request of data from a customer for usage of PC:UDC. In IDE4L the data storage function identifies the extraction of data for usage of SSAU.
Data encapsulation	N/A	This function is not described in IDE4L as it is not considered relevant for the architecture standpoint.
Averaged measurements	N/A	This function is not described in IDE4L as it is not considered relevant for the architecture standpoint.
Data “intermediate” collection	N/A	In IDE4L intermediate stages for collection of measurements are not considered. The measurement from single devices is directly sent to SSDXP.
PQ measurements	N/A	This function is not described in IDE4L as it is not considered relevant for the architecture standpoint.
RTU data collection	Measurement acquisition + Data storage	The function of data logging is included in the function “measurement acquisition”. Whereas the interface between RTU's protocols and database is realized in data storage function.
Measuring	N/A	This function is not described in IDE4L as it is not considered relevant for the architecture standpoint.
Connection establishment	Data presentation	The function “Connection establishment” in INTEGRIS is included in “Data presentation” in IDE4L.
Report of measured values	Data presentation	The function “Report of measured values” in INTEGRIS is included in “Data presentation” in IDE4L.
Reporting alarms	Data presentation	The function “Reporting alarms” in INTEGRIS is included in “Data presentation” in IDE4L.

Data Acquisition for SE	Data storage	IDE4L function “data storage” includes both storing and extracting data from database
SE Algorithm	Calculate state	No differences.
MPFV Algorithm	Check status of electrical variables + Control functions	Control of power flow and voltage is included in the set control functions of IDE4L. In IDE4L this function comes after the status of the system has been checked vs grid limit, and some contingencies have been detected and localized.
Substation Command Transfer	Compute control signals + Data storage	“Compute control signals” in IDE4L identifies the generation of package to be transmitted to IEDs for control actions. “Data storage” saves the information regarding the control actions.
Command/Acknowledge Transfer	Compute control signals	In IDE4L the control actions are sent directly to actuators without intermediates.
DER Control	Control functions	In INTEGRIS, the algorithm decides among: load disconnection, temperature setpoint, and PV inverter power setpoint, which resource to exploit. This “power dispatching” function is included in control functions in IDE4L.
DG control	Compute control signals	“Compute control signals” in IDE4L includes “DG control” in INTEGRIS.
Data of the fault	Data storage	In IDE4L the fault related data are stored at primary substation level.
Info of faulty area	Fault processing	“Fault processing” in IDE4L includes “Info of faulty area” in INTEGRIS.
Fault monitoring	Fault information acquisition	“Fault information acquisition” in IDE4L includes “Fault monitoring” in INTEGRIS.
Switch control	N/A	In IDE4L the IDEs manage the operation of switch control; hence it is not interesting for the architecture standpoint.

Reasons for fault	Fault information acquisition	In IDE4L, the data relative to the fault are measured and estimated at IED level.
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### New functions from IDE4L

Two functions have been introduced in the analyzed Use cases

- Data harmonization. In IDE4L a heterogeneous set of measurements is considered, the differences are in the reporting rates, delays, nature of the quantity. A step of data harmonization is needed to store and analyze coherently data in time series.
- Data filtering. In IDE4L a function, designed to filter data in order to store/send only meaningful and correct information, has been considered.

Furthermore, as previously mentioned, some new primary use cases have been defined with the consequence that the set of functions has been enriched regarding the clusters monitoring and control. The followings are the functions that have been added (for their description check the synthesis of functions section):

- Network Description Update (NDU)
- Customer Repository Update (CRU)
- Network Information Acquisition (NIA)
- Customer Information Acquisition (CIA)
- Forecast State (FS)
- Compute Schedule (SS)
- Scheduling

### 3.3.4 Incremental approach at primary use cases level – Automation architecture concept comparison IDE4L vs ADDRESS

#### Primary use cases

A comparison is conducted among primary use cases, identifying different functionalities that have been activated in IDE4L with respect to ADDRESS (Table 3.15).

Table 3.15: ADDRESS vs. IDE4L PUCs.

Address PUCs	IDE4L PUCs	General differences and comments
Configure load areas	Load Areas Configuration	The IDE4L use case does not include the LA updating.
Exchange flexibility tables	Flexibility table	No differences.
Validate technical	Off-line Validation	No differences.

feasibility	(OLV)	
Clear AD market	SRP and CRP Day-ahead and intra-day market procurement	ADDRESS use case describes the trading of SRP products only. In IDE4L CRP trading is not specified at this architecture concept level, but many market design options can be chosen. SRPs and CRPs are then considered as an input for the validation processes.
Activate AD product	CRP Activation	No differences.

### New primary use cases from IDE4L

In IDE4L project the clusters of business use cases have been enlarged in order to fulfill better the requirements for distribution smart grid automation. The following primary use cases have been added (for their description check the primary use case section):

- Real time validation allows evaluating the schedules for AD product with a short advance. It represents a second validation with respect of the off-line validation and allows increasing the robustness of the system.
- Commercial aggregator asset planning explains the management of DER units from the commercial aggregator point of view.
- Day-Ahead Dynamic Tariff allows determining a day-ahead grid tariff to alleviate a forecasted congestion.
- Day-Ahead Demand Response UC generates a flexible demand scheduled on a certain time horizon.

### Actors

Now, a comparison is conducted among actors for the IDE4L architecture with respect to ADDRESS (Table 3.16).

Table 3. 16: ADDRESS vs. IDE4L actors.

ADDRESS actors	IDE4L actors	General differences and comments
Aggregator	Commercial aggregator	No differences.
Consumer	HEMS	The home energy management system represents the interface of the DERs of the prosumers to the grid and to the electrical market.

DSO	DSO	DSO plays the role of technical aggregator in these UCs.
TSO	TSO	No differences.
AD Buyers	Balance responsible parties (BRPs)	No differences.
Market Operator	Market operator	No differences.

### New actors from IDE4L

As far as IDE4L vs. ADDRESS actors' comparison, new actors have been introduced in IDE4L:

- DMS: the DMS in Load area configuration use case implements an automatic function, called “Flexibility and DER status acquisition”, in order to obtain the status of the prosumer from the HEMSs and store it into a database for itself and for commercial aggregator's usage.
- CCDXP: in Load area configuration use case for storing flexibility information from the DERs. In Off-line validation for providing the information about the grid limit and the system's current and forecasted state.
- CADXP: allows the commercial aggregator storing and exchanging information for guaranteeing its operation.

### Functions

A comparison is here conducted among functions for the IDE4L architecture with respect to ADDRESS (Table 3.17).

Table 3.17: ADDRESS vs. IDE4L functions.

ADDRESS functions	IDE4L functions	General differences and comments
Macro load area configuration	Load area configuration	No differences.
Assignment each consumer to a load area	Load area configuration	No differences.
Flexibility table calculation (TSO perspective)	Flexibility tables	No differences.

AD product bidding process	Bid request + Bid submission	In IDE4L the mechanism which regulates the offer/bid process is split between bid request and submission.
Market clearing	Market clearing	No differences.
Technical validation reporting	Request reply validation	No differences.
AD schedule reporting	Compute schedule	In “compute schedule” function in IDE4L, the new schedule, obtained after the validation process, is sent to the aggregator. In ADDRESS, it generally means the exchange of tables among TSOs, DSOs and aggregator.
Technical feasibility evaluation	Data storage + Check status electrical variable + Control functions	In IDE4L, the technical feasibility evaluation process has been decoupled in three phases. First, the extraction of data from database, in particular grid limits and current and forecasted state of the system is performed. Then, the states vs limits are checked. Finally, some control functions run in order to obtain the AD product to be curtailed or modified.
CRP AD product activation	CRP activation	No differences.

### New functions from IDE4L

In IDE4L project two new functions have been introduced:

- Flexibility and DER status acquisition (FDA): it fulfils the requirement of obtaining the data of capacity and price for flexibility of DERs in the distribution grid.
- Data storage (DS): represents the possibility to extract and store data in the CCDXP to support the load area and validation use cases.

### 3.4 Considerations on the Assessment of the IDE4L Architecture Performance

The architecture is currently at a concept level; however, its development is strictly correlated to the expectations that have been done on it, as architecture for automation of distribution networks. It is consequently fundamental the definition of metrics for its evaluation. At this level, four types of metrics have been defined on a conceptual point of view. Nevertheless, in the deliverables D3.2 and D3.3 a greater level of definition will be reached, and whether necessary, other metrics will be introduced. Furthermore, several metrics from the demonstrations will be extracted and combined for the sake of the validation of the architecture. The proposed metrics are described in the following subsections.

### 3.4.1 Cost of architecture

The metric, inspired by the DISCERN project, takes into account the model proposed in [8], which describes the smart grid plan in zones and domains arrays. The cost of the new architecture is allocated in each one of the arrays, covering three dimensions: 1. Hardware components or devices (sensors, concentrators, etc.); 2. Software systems or applications (SCADA, DMS, EMS); 3. Communication. The cost is divided by a prior defined cost driver in order to make the costs comparable among different arrays. The total investment is then calculated for a generalized grid. An evaluation of the cost is available from the demonstration sites, considering the equipment to be bought.

### 3.4.2 Characterization of key features of the architecture

This group of metrics aims at quantifying a set of indexes which represent key features of the architecture, in order to compare them with other architectures and verifying major differences. The first index is the ratio between number of actors shared between use cases and total number of actors, and it is intended to represent the effort of synthesis of actors, even though a high number of actors does not necessarily represent a bad feature. The second index is the ratio between number of new actors and total number of actors, and it is meant to represent the innovation brought by the new architecture (it also depends on the starting point architecture). The third is the integration of existing standards. Some standard gap or some standard modification can emerge in the proposed architecture and it can then represent an important outcome. The fourth index is the hierarchical level of the architecture (how many nodes or how much nominal power is managed from a control node, e.g. from an automation unit or from the distributed management system). The fifth index is the amount of data to be processed in a control node and amount of data to be exchanged with same level control nodes. These two indexes, try to represent the level of hierarchy of the architecture, such concept is complex to be defined, and further proposals will be presented in the next deliverables.

### 3.4.3 Architecture robustness

This metric aims at defining the requirements of the architecture in certain scenarios, in order to validate it with respects to the most important requirements for the robustness. The scenarios to be considered are: 1. Loss of communication between actors and functions, 2. Latency in the communication, 3. Failure of hardware or software components which perform some critical functions. The effects of latency and packet loss in the communication can be connected to the organization of control nodes in terms of hierarchy and amount of information to be processed. Consequently, it is an issue to be taken into account in the phase of architecture design, and not only in practical development. For instance, the same control algorithm will have different performance depending on the number of control nodes which participate and the amount of data that each node has to process. The communication related robustness can be evaluated from some of the demonstrations, where the requirements for the communication are specified. In particular some scenarios with degradation of the communication infrastructure can be tested. Effects of failure of hardware or software components can be handled considering an IEC 61850 classification in terms of logical nodes [17]. Consequently, knowing the functions implemented in each logical node, it is possible to infer the effects of the failure of such devices. Failure in the actuators is not of interest as they are not part of the design of the architecture. In any way, the architecture should pass a so called “consistency check”, that is the check that all the types of information needed to perform the function are a priori available. This type of verification, should be done on the model of the architecture, meanwhile the robustness evaluation could be done on the implemented one.

### 3.4.4 Architecture feasibility for all IDE4L use cases

IDE4L architecture will be realized based on use case description and the SGAM framework [15]. Along the design process there will be several synthesis steps. The first one has been described in Section 3.1, regarding the synthesis of actors, functions and links coming from the UC description through the use case short template. The goal of this metric is to verify if all the use cases developed in IDE4L are logically feasible in the final architecture. The issues that may not allow the mapping of the IDE4L use cases in the new architecture are overlapping of functionalities, or function and actors divergence during the synthesis phase. This metric is intended to define methods to verify that such conditions are avoided. In the next deliverables the methods will be presented.

## 4. Automation Architecture Developments

This chapter describes the conceptual architecture developments to be done in the next task within WP3, namely T3.2. In order to do so, some reference to standards, technologies, regulation (&trends) concerning the following four big areas are discussed:

- Distribution Automation,
- Communications,
- Monitoring Measurements
- Control Centers

The idea is to conceptually describe the automation architecture developments that are envisioned, to be in line with the specifications of active distribution network concept previously defined in deliverable D2.1, and basis for the next phase of the architecture implementation in T3.2. In T3.2, the detailed description of the UCs will allow to fully define all layers of the SGAM architecture. In order to enable the practical implementation of the architecture, each function will be built up from IEC 61850 logical nodes, interfaces and logical communications will be defined, together with their requirements and with all data models. This way the substation environment is expected to be defined in an operative way in a fairly straightforward manner.

A similar process will be applied to the environment external to the substation: the home energy management systems will be mapped to the IEC 62056 standard, some information of the distribution network, such as network model and topology, will be mapped in Common Information Model (CIM) standard.

Finally, many of the business functions are not covered clearly by any standard, and hence in this area we expect IDE4L to identify standardization gaps and feed these information back to the standardization bodies.

### 4.1 Architecture Developments to be done in Distribution Automation

#### 4.1.1 Architecture developments required for distribution automation

The Substation Automation System refers to the system and all the elements needed to perform protection, monitoring and control of a substation, and of connected assets (inside the substation such as transformers, busbar, etc or outside the substation such as grid lines, loads, etc). These automation systems are becoming wider, adding every day new and more complex systems to this automation context due to an increasing interconnection and intelligence all over the grid.

Feeder automation is aimed to remotely monitor and control secondary substations (MV/LV and switching stations) in MV network. In addition to fault management, MV network and MV/LV secondary substation monitoring are the typical functionalities of feeder automation.

Advanced Metering Infrastructure (AMI) offers also functionalities for LV network automation while the primary role of Automatic Meter Reading (AMR) is to provide energy consumption data to the utility for billing and balance settlement purposes. The utilization and integration of AMI into network operation systems can be seen as an extension of SCADA and distribution automation to the LV level. AMI system can be utilized in many functions of a distribution company, e.g. to support network operation (e.g. automatic

LV fault indication, isolation and location, and network near real-time monitoring), network planning and asset management (e.g. exact load profiles for network calculations), power quality monitoring (e.g. interruptions, voltage characteristics), customer service, and load control or demand response services.

According to the following diagram (Figure 4.1) representing the SGAM function group division, it is possible aggregate these automation systems depending on the domain of action for devices on them.

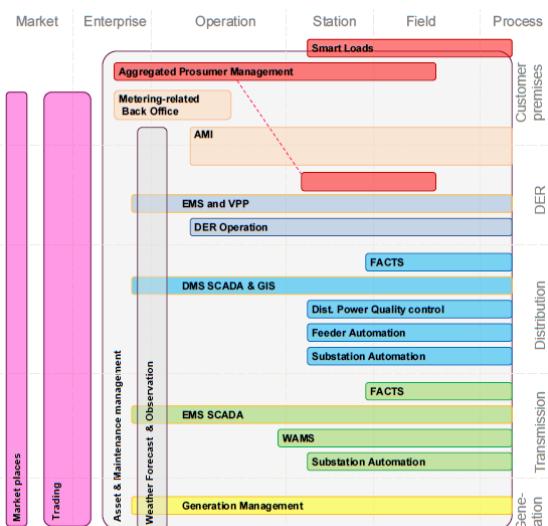


Figure 4.1: SGAM function group diagram.

These groups are:

- Substation automation in Transmission
- Substation automation in Distribution
- Feeder Automation
- DER Automation
- LV Systems Automation

Active network management is based on distribution automation and flexibility services of DERs.

Distribution automation consists of control center information system, substation automation, secondary substation automation and customer interface (e.g. smart meters). Distribution automation realizes the supervision of the network state, control of network breakers and switches, and monitoring and controlling of primary and secondary substations, and emergency (direct) control of DERs. This is the basis for the ANM. Secondly aggregation system provides information about DERs and also provides flexibility services (indirect control of DERs) for network management.

The new scenario of distribution network requires also new functionalities for the operation of the distribution networks like distribution state estimation, automatic FLISR, coordinated voltage control, power flow control, static and dynamic distribution model order reduction to coordinate with TSOs, and the availability of stability indicators – using both models and measurements.

The automation concept revolves around three design points: (i) Hierarchical and distributed control architecture in distribution network automation, (ii) Virtualization and aggregation of DERs via aggregator and (iii) Large scale utilization of DERs in network management. The concept of active distribution network was presented in Deliverable 2.1 “Active distribution network”.

The hierarchy of distribution automation includes three levels: primary, secondary and tertiary levels. Primary controllers and protection devices, in general IEDs, operate autonomously and have the fastest response in system disturbances. Secondary level includes cooperation of several IEDs like interlocking schemes in protection or automatic coordination of controllers in the specified network area. Tertiary level manages the whole system typically based on control center level IT systems and operator actions.

Distributed automation architecture will enable the scalability of the system. The scalability of the monitoring system is a critical question from the distribution automation viewpoint. Instead of collecting and analyzing a few thousands of measurement points, the future monitoring system should be able to handle millions of measurements and a large volume of measurement data. Therefore the architecture of automation system is based on a hierarchical structure, data analysis in the field and server push instead of client pull. The automation system should also be based on standard IEC 61850 to enhance and simplify the integration of subsystems. Data exchange based on standardized messages and data models is an essential requirement of DSOs to develop automation and IT systems for smart grid [56].

Data handling, storage and analysis is also becoming important due to huge volumes of data. On-line and automatic handling and analysis of data is needed to reduce the amount of data transfer to control center. Only relevant information should be represented in real-time to the network operator. Distributed data storage allows tracking every detail without real-time communication to control center. Data may be later replicated to centralized asset management database for off-line data analysis purposes [57].

### ***Global control architecture***

Control architecture can follow a hierarchical structure distributed among primary and secondary substation and control centers. A proposal is the following:

- Primary controller:
  - Physically located in the control unit such as DER elements
  - Running on real-time
  - Control area: controlled unit
- LV Secondary controller:
  - Physically located in secondary substation automation
  - Running with fixed interval, e.g. 10 minutes
  - Control area: Secondary substation and LV feeders
- MV Secondary controller:
  - Running with fixed interval, e.g. 10 minutes
  - Control area: MV grid; Primary substation and MV feeders
- Tertiary controller:
  - Physically located in control center
  - Overview of the whole distribution grid (both MV and LV)
  - Running with fixed interval like once a day or “on demand” in case of faults or unexpected events

Secondary and Tertiary controllers will use the information available in the distributed DB located in the Primary and Secondary Substations. Outputs from Monitoring, forecast and state estimation modules will be stored in DBs.

#### 4.1.2 Development for distribution automation

##### ***Development for substation automation in Transmission***

The Substation Automation System in Transmission refers to the systems involved in primary substation level operation, monitoring and protection. They may also act as remote terminal for upper levels of grid monitoring and control for operation and/or maintenance in fully automatic conditions or even supporting remote or manual operation.

##### **Architecture description and devices involved**

Most standards related to present used technologies for system automation in transmission domain are described in IEC/EN 61850 standard series.

Some of the relevant standards in this series applying to transmission automation systems were firstly defined for substation and feeder environment, but were latterly also adopted out of their scope:

- IEC 61850-7 Communication structure
  - EN 61850-7-4, EN 61850-7-3. Information modeling
  - EN 61850-7-2. Abstract communication service interface
- IEC 61850-6. Configuration language for communication

And some other were defined later to cover the gaps out of the substations and could also be relevant for substation automation in transmission. This is the case of all other possible interconnected devices downstream, some of them for particular generation schemes:

- IEC 611850-7-410 for Hydro power plants data modeling
- EN 61850-7-420 DER
- EN 61400-25 related to wind farms

Communications are based on EN 61850-8-1 and IEC 61850-90-1 for the communication between substations. For upstream communication, traditional protocols EN 60870-5-101, EN 60870-5-103 and EN 60870-5-104 are used, following mapping recommendations described in IEC 61850-80-1.

Also cyber-security aspects apply for substation communication, as described in IEC 62351 (all parts).

In the future, coming standards will probably change communication perspective for automation outside of the substation.

IEC/EN 61850-8-2 is being developed for specific communication service mapping (SCSM) – mappings to web-services, and these modern communication protocols are expected to replace the previous mentioned protocols in the SCADA control link to the substations.

Other IEC standards will be used for specific DER modelling and network management, such as IEC 61850-90-4, IEC 61850-90-7.

##### ***Development for substation automation and feeder automation (Distribution)***

Substation Automation Systems for Distribution domain refers to the system and all the elements needed to perform automated operation of a primary substation, and of connected assets (grid lines, loads, etc.). Feeder automation system refers to the same concept but related to the operation of components placed along the MV network itself (feeders).

The typical considered operations for substation automation are protection functionalities, automatic equipment control for network reconfiguration, including possibly feeder reconfiguration, automatic power quality regulation.

As in the transmission case, these systems may also act as a remote terminal for upper levels of grid monitoring and control for operation (monitoring & control) and/or maintenance, in a fully automatic way or in support of remote or manual operation. In this domain, these systems may be used for Automated MV/LV transformer Substation System including also LV feeders placed on the MV/LV transformer substation and typically (but not limited to) MV-switching elements connected to the MV/LV transformer, (controllable) MV/LV transformers and automated low-voltage boards.

In the particular case of feeder automation this includes MV fault detectors, switches, disconnectors and circuit-breakers, with or without reclosing functionality placed between the primary substation and the secondary substation.

#### Architecture description and devices involved

Due to the similarities, most of the standards involved in distribution domain are very similar, if not the same, to the standards involved in transmission domain.

As a main description, IEC/EN 61850-7-4 will apply for modeling in the information layer, although automated MV/LV substations are not really covered yet, and IEC/EN 61850-8-1 applies for communication layer within the substation (for any kind of data flows except sample values) and EN 61850-9-2 (for sample values) are used to support the selected set of High level use cases. IEC/EN 61850 mostly replaces the former EN 60870-5-103, used for connecting protection relays. In the specific case of automated MV/LV substations, communications are more commonly based on industrial networks.

When related to outside the substation communications, EN 60870-5-101 and 104 are still being used for vertical communications, while IEC 61850-90-5 (over UDP) or IEC 61850-90-1 tunneling are used for peer to peer horizontal communication. As it was the case for Transmission level, it is expected that the future vertical communications will rely on web services technology (IEC 61850-8-2), thus providing easier and versatile deployment and security enhancements.

In the case of feeder automation there is a similar schema, where 61850-90-4 can be applied for distributed substation guidelines.

Other specific standards may apply also in this context, as the case of IEC 60255-24, COMTRADE, common format for disturbance recording data exchange.

Automated and standardized configuration of substation devices is also common for transmission and distribution levels. Technology is now available and standardized. However, because the revamping of an existing primary substation takes time, the 61850 has been applied mainly in low number of new substations, up to now.

#### VPP interconnection and DER

In this wider and distributed scenario, distributed energy resources and VPPs increase the complexity of the automation systems, while specific standards appear to propose data management and communication solutions.

## Architecture description and devices involved

The information layer of DER operation is also mostly based on the IEC/EN 61850 information model. In this case, it is particularly relevant the standard EN 61850-7-420, specifically developed for this context, and EN 61850-7-4 is the core part depicting this model which is extended by various standards for DER operations:

- EN 61850-7-410: Hydroelectric power plants
- EN 61850-7-420: DER logical nodes
- EN 61400-25-2/3: Wind turbines
- IEC 61850-90-7: PV inverters
- IEC 61850-90-9: Batteries
- IEC 61850-90-10: Scheduling functions
- IEC 61850-90-15: Multiple Use DER

The communication layer is provided by EN 61850-8-1, mapping on MMS and Ethernet. EN 60870-5-101 and 104, may also apply, and the same for EN 61158 and IEC 61784-1 field buses, while the trend will probably be the use of 61850-8-2 Specific Communication Service Mapping (SCSM) – mappings to web protocols, and EN 61968-100 for CIM mapping over web services or Java Messaging System.

Other traditionally applied standards in control environments are used for generation control schemes where devices usually need to be able to have programming flexibility in response to variable operation environments. IEC 61131 for programmable logic controllers and IEC 61499 for distributed control and automation.

New standards for more specific cases like batteries, DER inverters and modeling of logics are expected in the IEC 61850 series.

## *LV automation and smart loads/smart customers (Customer)*

### Introduction

Traditionally, distribution automation mainly focused on high voltage (HV) and medium voltage (MV) level. Low voltage (LV) grid and secondary substation, on the other hand, have very low level of automation. The LV electrical network is actually getting more and more importance because of the developments involving the power distribution sector: the progressive diffusion of photovoltaic (at both industrial and residential level) and other power generation systems, such as micro co-generation, the continuous increment of electrical/hybrid cars and also the demand/response schemas. Because of that, there is a clear trend that more intelligence will be needed at LV level.

LV lines are often equipped with LV breakers including a magneto-thermic protection to avoid the propagation of fault current to the MV/LV transformer. The main limitation of this system is that it cannot be remotely operated. This means that a field crew has to be dispatched in field every time there is maintenance on the LV line. In future, the trend will be to install remotely controllable breakers.

Other possible technologies to control LV networks are also becoming available such as OLTC for MV/LV transformers, FACTS devices including energy storage, and microgrids.

Also from a measurement standpoint, the LV has a little technology penetration but – because of the increasing DG penetration – some DSOs have already started the deployment of a monitoring system to highlight inverse power flow, voltage variations and phase unbalances. A separate power quality

monitoring system, normally including power quality meters at primary substations, might be extended to secondary substations and customer connection points, where measurement devices are installed permanently or temporarily (based on customer or DSO request). Recently a combination of overall monitoring and power quality monitoring systems have been started to develop [51].

However, the main effort done in the last years was on the installation of electronic meters. The first Automatic Metering system, where already present today, have been conceived for billing and customers relation purpose and not for the technical management of the grid. Despite of that, many stakeholders believe that the new generation of smart meters should be used also for that. Because of the strategic role that the metering system will play in future, the rest of the document will focus on this system.

In the case of LV prosumers, the use of tele-controlled switches or breakers is already regulated, imposing the use of this kind of devices connected to the local distribution control system. In case of maintenance, all the producers in the line will be disconnected if needed, and the line will be earthed.

#### Involved devices or functions

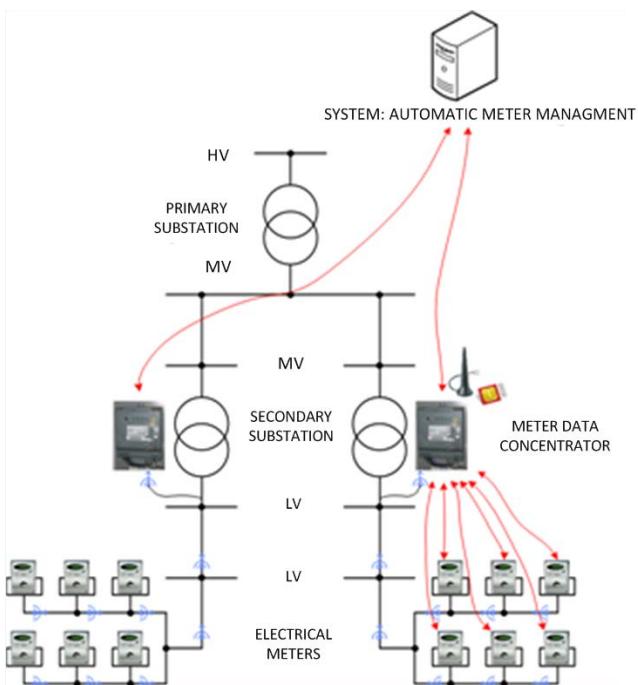
The LV network – connecting the end customers to the secondary substations – is part of the Automatic Meters Management system domains. This system has been already deployed in some European Countries. For example in Italy it is active since 2006, when the Italian authority (AEEG) imposed the progressive substitution of the old electro-mechanical meters with the new digital ones. The system is today used for the customer management services, especially for fiscal purposes as, for example:

- Reading of energy profiles at 1/4 hourly detail (typically monthly);
- Activation/deactivation of customers;
- Contractual power variations in the PPA (power purchase agreement);
- Power curtailment in case of nonpayment;
- Meter monitoring to avoid/discover eventual sabotages.

Much other technical information such as supply interruptions are recorded, as suggested by the Italian EE Authority, even if they are at the moment scarcely used.

The system is typically implemented with a three-layer architecture, composed of:

- Electronic meters per each customer,
- A meter data concentrator per secondary substation, which aggregate data coming from all the customers fed by that substation,
- A central IT system collecting data from meters data concentrators.



**Figure 4.2: Basic architecture of an Automatic Metering Management System.**

A second-generation electronic meters (smart meters) have already installed in some countries. These meters may, together with control center and IT systems, monitor and manage LV network faults (indication, location, isolation and registration of low voltage network faults) and monitor power quality at LV network [52]. Demand response might also be realized via a smart metering system like operated by a Finnish DSO [53], [54]. Demand response functionality is based on interface requirement of smart meters in Finland for direct load control and Time-of-Use tariff control.

#### Information modeling standards

In this paragraph, we only recall that these meters work mainly through a non-standard application protocol, which does allow neither the adoption of third party meters or of course the collection of data through third party concentrators.

The most promising standard is today the DLMS/COSEM, which has been already used by different suppliers:

- COSEM [IEC 62056-62], C0mpanion Specification for Energy Metering, is a specific object-oriented model for the EE meters communication interfaces, providing a complete view of their available functionalities directly through the interfaces.
- DLMS [IEC 62056-53], Device Language Message Specification, defines an application layer which doesn't depend from the inferior layer. It has been developed with the aim to provide an interoperable environment in which to exchange metering data/information.

DLMS/COSEM is a standard which uses COSEM to define the EE meters interfaces and DLMS for the data exchange between different devices. More specifically:

- The interface model provides only a functional description via building block, without describing the specific aspects of its implementation.
- The communication protocol defines the data access and transport.

The DLMS/COSEM standard is divided in three blocks:

- Modeling of both the device interfaces and the rules for the data identification;
- Messaging: mapping of the interface model on the messages;
- Transporting: message transport through the communication layer.

In [25] can be found a synthesis of the main aspects of paragraph 1, while in paragraphs 2 and 3 are described in [26].

#### DLMS/COSEM Communication Framework

The COSEM-based systems data exchange methods are based on a client/server architecture, in which the meter device usually acts as a server and the data concentrator (or the Home Gateway) works as a client. This scheme is completely similar at the IEC 61850 report service, where the end-device has the server role, while the data collector (i.e. a substation SCADA) is the client. One client can communicate with one or more servers, and one server can at the same time dialogue with more clients.

The communication profile includes many different protocol levels: as it always happens, each of them provides services at the higher levels and makes use of services from the lower levels. A representative scheme of this profile can be found in Figure 4.3.

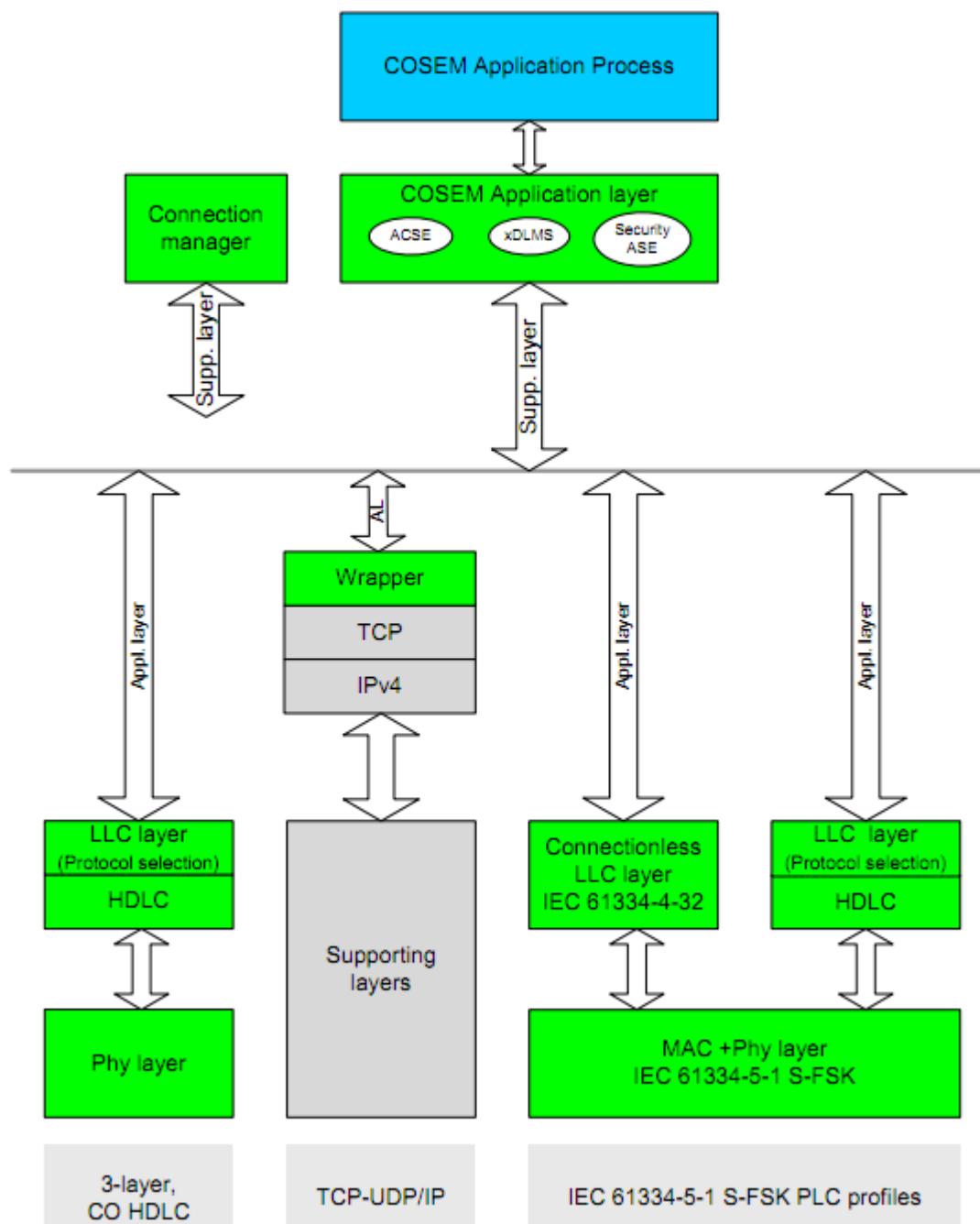


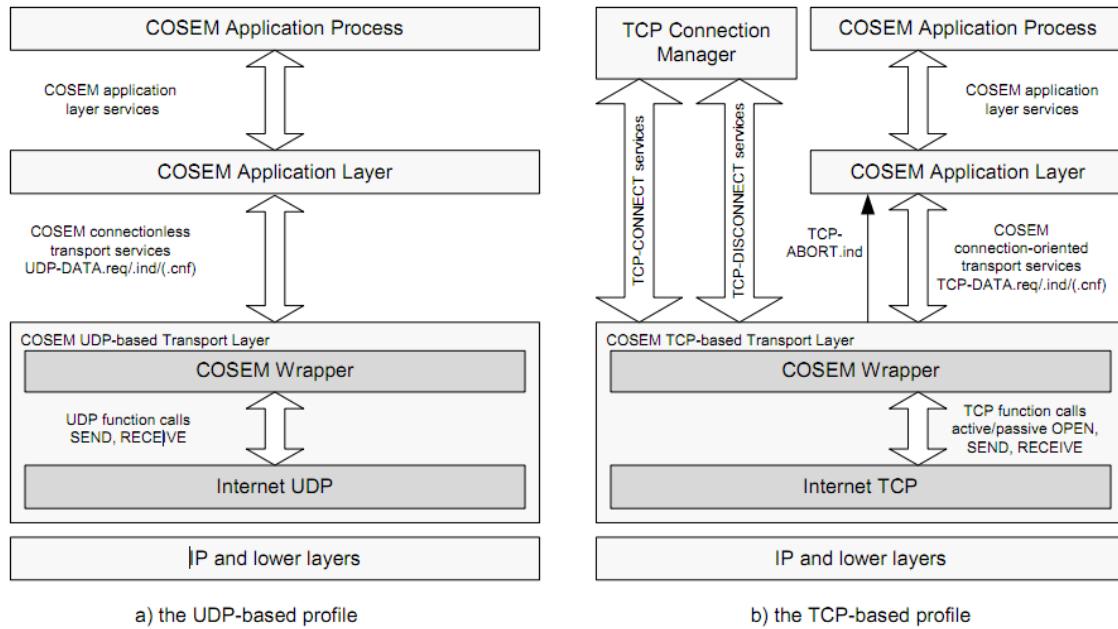
Figure 4.3: DLMS/COSEM communication profile [26].

COSEM Client and Server use the services in the upper part of the stack protocol, which defines xDLMS and ASE. In the lower part of the stack the different layers and protocols for each communication technology used for the data transfer are defined. A COSEM profile is made by a vertical pile including both the application and one communication/control parts.

The profiles already defined are three, and other can be developed: however, the most interesting of them is surely the high-performance TCP/IP based profile, which allows the communication through the most different media such as Ethernet, ISDN, GPRS, PSTN or GSM by using the PPP. In all those cases, the COSEM application layer relies on the COSEM transport layer based on TCP/UDP.

## COSEM transport layer for IP networks

The COSEM transportation layer for the IP networks (COSEM\_on\_IP) manages both connection-oriented and connection-less modalities, respectively based on TCP and UDP and both mapped on the 4059 default port. An intermediate layer called “COSEM Wrapper” grants the access at these protocols, by acting as an adapter.



**Figure 4.4: COSEM\_on\_IP transport level profile [26].**

When using the COSEM\_on\_IP profile, the COSEM application level can be considered just like any other application protocol (i.e. HTTP, FTP, SNMP, ...) and can co-exist with the other IP protocols.

As a connection-oriented transport protocol, the use of TCP involves three phases:

- connection establishment,
- transfer phase,
- connection closing.

The COSEM connection-less is on the contrary UDP-based, so it represents the best choice for applications requiring more efficiency but a minor transmission reliability such as alarms or notifications like tampering or open door events.

The COSEM application level is shown in Figure 4.5.

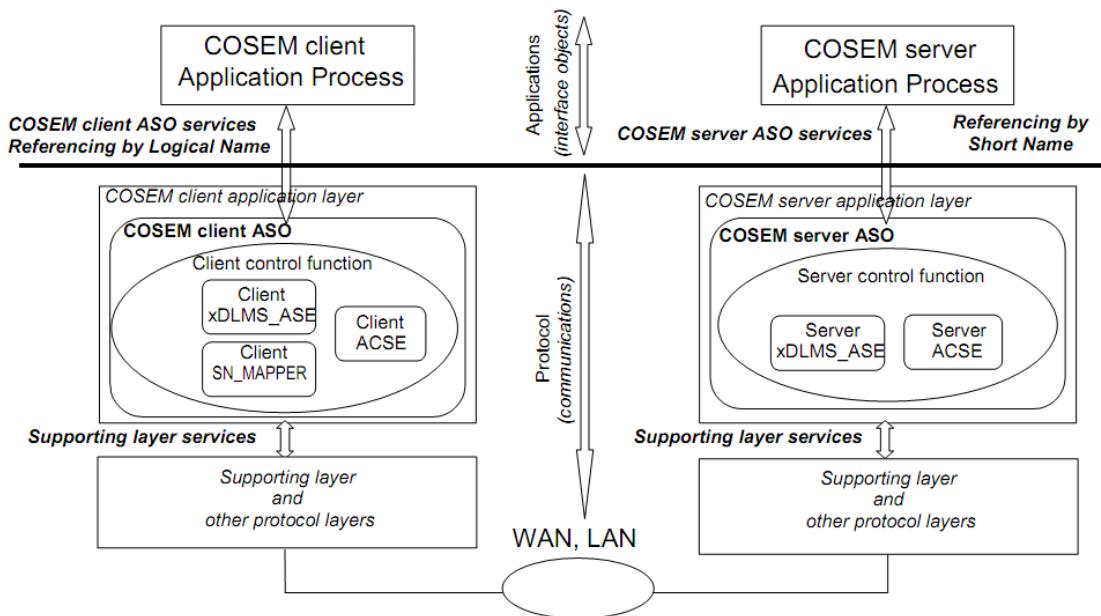


Figure 4.5: COSEM application level structure.

The COSEM Application Service Object is the main component in the application layer, it provides services to the COSEM Application Process and is made up by the following components in both client and server:

- The Association Control Service Element (ACSE) establishes, maintains and releases the associations between the applications;
- The Extended DLMS Application Service Element (xDLMS\_ASE) provides the transfer services between COSEM Applications;
- The Control Function (CF) specifies how the ASO Services can call the ACSE and xDLMS\_ASE primitives.

The xDLMS\_ASE main task consists of providing data transfer services between COSEM applications.

## 4.2 Architecture developments to be done in Communications

### 4.2.1 Architecture developments required for communications in distribution networks

#### *Some reference to standards for enabling an effective communication system in active distribution networks*

It is expected that the increased use of wide-area measurements will result in a more efficient and reliable use of corrective actions for power system-wide disturbances like rotor angle, frequency and voltage stability issues. This type of application requires accurate phasor and frequency information from multiple synchronized devices. Today, Phasor Measurement Units (PMUs) are the most accurate and advanced time-synchronized technology available. They provide voltage and current phasor and frequency information, synchronized with high precision to a common time reference provided by the Global Positioning System (GPS).

It is expected that active distribution networks will have more significant impact on power system stability than previously due to increasing number of RESs. Therefore dynamic behavior of distribution systems should be considered in power system stability analysis.

The first standard for time-synchronized phasor measurement (from now on, synchrophasors) was completed in 1995. It was IEEE 1344. It specified synchronization to UTC time, time accuracy and waveform sampling requirements, but did not specify communications.

IEEE 1344 was renewed in 2000. This included creating a method for evaluating synchrophasor measurements and defining a communication protocol to operate over networks.

In 2005, IEEE Std. C37.118-2005 replaced IEEE 1344. This version included both measurement requirements and real-time data transfer requirements. To simplify widespread adoption of synchrophasor measurement technology and facilitate the use of the other communication protocols, IEEE Std C37.118-2005 was split into two standards:

- IEEE Std. C37.118.1-2005, with measurement requirements;
- IEEE Std. C37.118.2-2005, with data transfer requirements.

The split facilitates the harmonization of IEEE Std. C37.118-2005 with IEC 61850. With this harmonization, a double benefit is achieved:

- PMUs become interoperable – IEC 61850 is an international standard for power utility automation. One of the reasons that promoted the development of this standard was to achieve true interoperability between systems from different vendors.
- PMU-based monitoring systems can be seamlessly included to power utility automation systems.

The objective of IEC 61850 is to specify requirements and to provide a framework to achieve interoperability among devices in power utility automation systems: measurement equipment, protection relays, meters, etc.

IEC 61850 series define:

- Abstract Communication Service Interface (ACSI). It proposes:
  - An abstract data model to represent common information found in real devices.
  - A set of abstract communication services: connection, variable data access, unsolicited data transfer, device control, etc.
  - The definition of ACSI is independent from any specific underlying protocol.
- Specific Communication Service Mapping (SCSM). It proposes how to map ACSI models onto real protocols that are common in the power industry.

Part 90-5 of IEC 61850 series defines how to transmit synchrophasor information. The first (and only) version of the document was published in May 2012.

In general terms, IEC 61850-90-5 is used to model synchrophasor according to its data model, and transmit it using Sampled Value (SV) protocol over UDP/IP and using GOOSE protocol over UDP/IP.

#### State of the art of IEC 61850 and IEC 61850-90-5 software libraries

On the whole, IEC 61850 is a very complex standard, far from the simplicity of other industrial communication protocols such as Modbus, CAN, DNP3 and even CANOpen and OPC. For this reason, many manufacturers use commercial software libraries to include IEC 61850 to their products.

For the time being, the most well-known commercial libraries are:

- MMS-EASE Lite – It has been developed by SISCO, in C language. It is sold in source code form, and allows to create both full IEC 61850 clients and servers. It works on Windows, Linux and QNX. Most products certified by KEMA use this library.
- IEC 61850 Source Code Library – It has been developed by Triangle Microworks. It is sold in source code form, in ANSI-C, C++ or .NET. It works on Windows and Linux.
- PIS-10 – It has been developed by SystemCORP. It can be purchased in source code form or as compiled library. Version 1.0 was released at the end of 2010, and it meant a radical change in the sector: it was (and still is) the only one that can be purchased as a compiled library and at low price. It can be implemented on a wide range of embedded microprocessors and software operating systems.

Architecture developments required for PMU communication according to IEC 61850-90-5

In the IDEAL project, we aim at developing a library to generate and parse IEC 61850-90-5 messages (Figure 4.9).

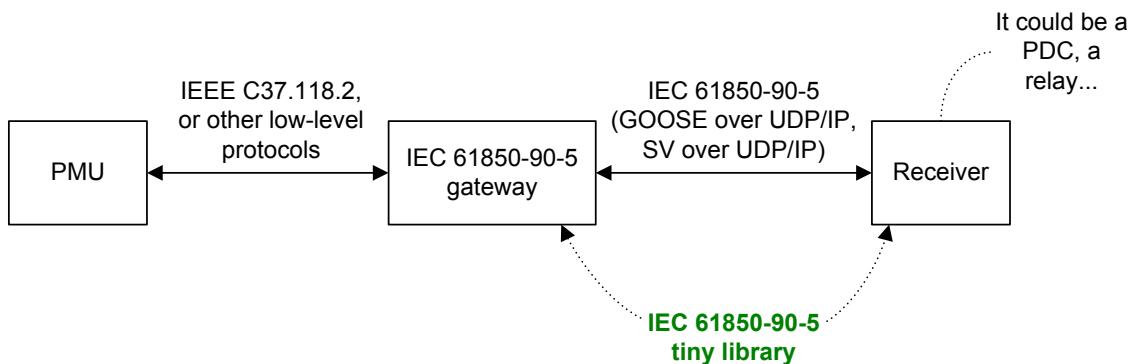


Figure 4.6: IEC 61850-90-5 library for PMU communications.

The library will implement the following protocols:

- GOOSE over UDP/IP
- SV over UDP/IP

During the development of the library, the following challenges shall be met:

- The library can be compiled for different microprocessor architectures,
- can be compiled with GNU toolchain,
- uses basic GNU libraries (stdio, stdlib...),
- does not use any operating system specific library (no winlib, no pthread, no semaphores, ...), and
- can be used in embedded platforms with or without operating system.

### **PLC communications for the active distribution grid**

With coming advent of robust modulation standards for digital communications applied in fields such as fiber optics or wireless communications and now being applied to PLC, such as Orthogonal Frequency Division Multiplexing (OFDM), the robustness in the system makes it more applicable, so in Europe and Asia-Pacific, PLC technology is the mostly deployed and favorable technology for smart metering [10]. In North America it is more extensively used the wireless systems, because, while in Europe in the majority of cases each transformer serves tenths or hundreds of costumers, in North America it is much less, so there are some situations in which just one smart meter is served by a transformer. Hereafter, a specialized UC,

namely “PLC communications for the active distribution grid”, in accordance to the UCMR system set-up within IDE4L, is described.

#### Description of the main actors

In this part, the main actors that represent this UC are briefly described and Figure 4.10 shows the mapping of actors and functions as done in previous chapters. The present UC describes the chain of such a communication from the final user generating the data, until the AMI Grid operator that manages such data (DSO). Other actors, such as disturbing loads, describe the functionalities of the different loads, basically low-cost power converters or other converters that integrate renewable generation into the power grid, and may generate disturbance in the transmission of the PLC signal.

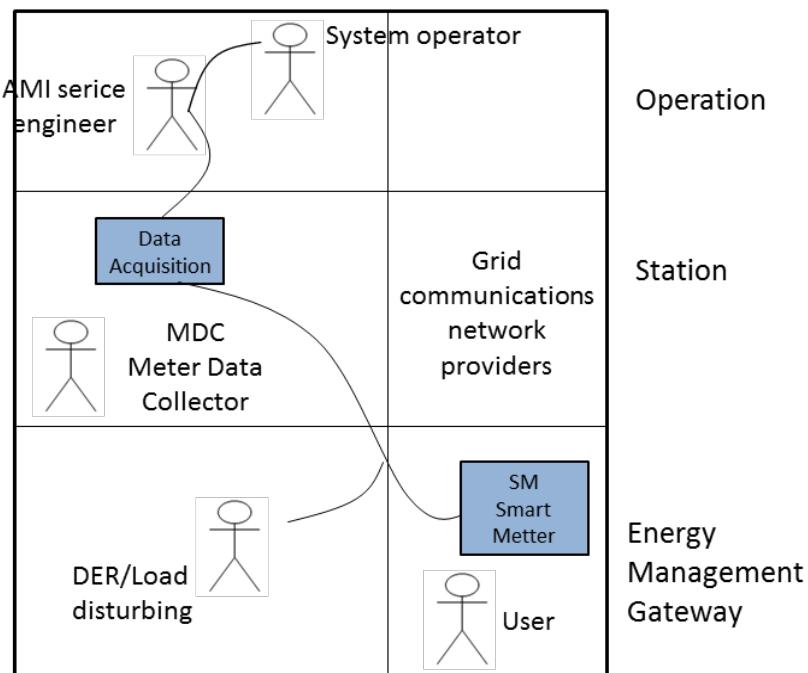


Figure 4.7: Mapping of actors and scenarios.

#### Interfaces between actors

At this point, the different interfaces that come across all the actors, such as the LV power line configurations (network topology, Neutral and Earth configurations) are located. The distribution power network is the main interface between the actors in the PLC communications system for the active distribution grid, as it is the physical layer through which both the power that produces high frequency disturbances and also the channel for the data sending flow.

From the LV-busbars service cables are bringing power to the customers and also communications in the case of PLC being transmitted from substation to the customer. From LV transformer side (Y-configuration with the neutral grounded) PLC signal is injected between the phase and neutral, because not every building includes earth protection (in such case neutral is short-circuited with earth).

The expected high penetration of renewable energies and DER in the LV networks also implies a high penetration rate of static converters interfacing such renewable energies and DER with the power grid. A common reference framework representing the different common practices in Europe as well as the different type of prosumers – i.e. residential, industrial and commercial – is needed in order to completely

define the interface for the purposes of this work. The work of CIGRÉ Task Force C6.04.02 is utilized for this purpose.

Additionally, the type of line conductor varies depending on urban/rural areas and their respective high/low load density. Depending on the power grid, different interconnections and topologies are used. For Urban areas, for example, underground cables enclosed in a metallic or galvanized conduit may be found, whereas for rural areas overhead lines constructed with bare conductors made of aluminum are typically found.

Finally, it is worth mentioning that the grounding is highly dependent on regional common practices, being the most common the TN type and the TT type, as defined by IEC 60364. The first letter T means that the neutral of the transformer is connected to ground. The second letter N means that the frame of the devices being supplied are connected to neutral, whereas the second letter T means that such frames are connected locally to ground instead of a neutral conductor.

### Definition of protocols and standards

There has been significant effort to put in place by regulatory bodies standards for PLC data communications of relevant importance in smart grid network, in particular in the low frequency regions derived from 10 kHz to 500 kHz. As an example, the European Standard CENELEC 50065-1 [30] has divided the 3 kHz to 148.5 kHz low frequency powerline spectrum into four different frequency bands referred as CENELEC A, B, C and D bands. On the other hand, in the United States, the FCC (Federal Communications Commission) has allocated the whole spectrum between 14 kHz and 480 kHz to one wideband channel often referred to as FCC band [31]. The dominance of PLC for smart metering is already observed in European countries (Spain, Italy, Netherlands,...) knowing that PLC is a cheap and reliable means of providing new and intelligent applications from last mile of the distribution grid.

The communication protocol will be based on PRIME. Other standards will be included in this study in relation to the low frequency bands of PLC. Open standards like G3-PLC can be included, but are not included patented standards such as Aclara, ANSI/CEA-709.1-B (IEC 14908-1 LonWorks), IAd, Watteco or Ytran.

In regards to regulations, the broadband PLC is not regulated; the only regulation available is about the allowed signal power and the limitations in the Electromagnetic Compatibility (EMC) disturbances. Such regulation studies are out of the scope of this study. In the following, protocols will be described in reference to the modulation type, a simple modulation (OOK, PSK) or a more complex modulation (OFDM type).

#### a) Non-OFDM Narrow-band PLC

There is an old-use specification for home automation, used before by Lonworks in order to send simple commands, named X-10 where the transmission uses a burst signal at 120 kHz, synchronized with the zero crossing of fundamental frequency (that means a bit rate of 50 or 60 bps), that becomes modulated by the simple On Off Keying (OOK) modulation scheme. Lonworks was developed by Echelon [32], with the intention of replacing X-10 in home automation (lighting and alarm application and industrial) first using the modulation scheme based on Spread Spectrum FSK (Frequency Shift Keying), or BPSK (Bi-Phase Shift Keying) in the two frequency bands from 125 to 140 kHz in the primary band and from 110-125 kHz in the secondary band, with the data rate up to 5.2 kbps in the CENELEC band C. In 1999 it was standardized by

ANSI (CEA-709.1-B), and just in 2005 it was approved by UE (EN 14908). It is an open protocol standard from 2009 ISO/IEC 14908-1. As an example of application for power metering, the Enel “Telegestore” smart meter is one of the first adopting the Lonworks neuronchip for its PLC communications.

### b) OFDM-based Narrow band PLC

Also used in home automation, smart metering and smart grid solutions in general, there is an improved and more robust modulation modem for PLC (also more complex in its implementation) that uses OFDM modulation with a set of subcarriers very close to each other. This approach maximizes bandwidth utilization, thus allowing advanced channel-coding techniques for robust communications as well as higher data rates [33]. By improving the type of modulation, it is possible to become more robust against interferences and some frequency selective attenuations, so become more reliable with an increase of the data rate. In the following lines two initiatives are described that generate two open PHY and MAC specifications for low-data rate transmission in the low-frequency band.

#### **PRIME**

One example of specification that uses OFDM is the open, public and non-proprietary communication solution named PRIME (PowerLine Intelligent Metering Evolution) for smart metering [34], initialized by the PRIME Alliance (Iberdrola, Texas Instruments et al.). In this case, the OFDM PRIME PHY specification provides for the frequency band from 41.992 kHz to 88.867 kHz, divided into 97 equally spaced subcarriers (96 data subcarriers plus one pilot), reaching up to 130 kbps raw data rate (with 8-DPSK modulation). In the creation of the OFDM symbol, the sample rate is 250 kHz and the IFFT has length of 512.

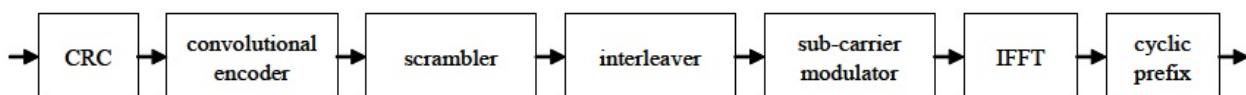


Figure 4.8: Block diagram of OFDM PRIME transmitter PHY [35].

PRIME specification covers physical (PHY) and media access control (MAC) layer for CENELEC A band PLC over low voltage grid. In terms of MAC, PRIME is fully plug-and-play, it is a tree build topology where there is one master managing the subnetwork and all the other devices behave as slaves. These communication components are part of the devices of a Smart Metering network. The master would be the concentrator, which has the Base Node (BN) element. The slaves would be the smart meters, which also have a metering application and a PRIME PLC node named Service Node (SN).

To achieve full coverage, every SN has three operating states, i.e. Disconnected, Terminal and Switch. Each SN can become a repeater candidate in order to help other meters access the PRIME subnetwork. The BN selects which SNs will finally become repeaters. PRIME technology adapts this topology to changes in the grid conditions, maintaining the stability and availability of the communications with the objective of detecting possible network changes, adjusting traffic continuously. The PRIME periodic Alive Control Packets are defined for this purpose (during Alive Time period).

It is also worth noting that the PRIME PLC system already supports a mechanism for an interoperable LV phase identification, which is also an integral part of the PRIME standard (under improvement phase by PRIME Alliance).

#### **G3-PLC standard**

Another protocol that uses OFDM modulation to overcome the interference problems and bandwidth limitations is the G3-PLC standard [36][37], which is the real competitor of PRIME, with larger bandwidth, extending below the CENELEC regulated frequencies. The data rate in CENELEC A band (from 35.9 kHz to 90.6 kHz) is up to 33.4 kbps, using up to 36 subcarriers, with a sampling rate of 400 kHz and IFFT size of 256. But considering the whole FCC frequency band, G3 uses 72 subcarriers from 145.3 kHz to 478.125 kHz, with a sample rate of 1.2 MHz and an IFFT size at 256, reaching data rate of 207.6 kbps. This is a new specification that was published in August 2009 and developed by Maxim Integrated Products and the French Electric utility company ERDF. In addition to the OFDM-based PHY, the G3-PLC specification includes an IEEE 802.15.4-based MAC layer suited to low data rates, and a 6LoWPAN adaptation layer to transmit IPv6 packets over smart grid network. The specification also includes:

- MAC-level security using AES-128 cryptographic engine
- Coexistence with older S-FSK (IEC 61334) and broadband systems (IEEE P1901 and ITU G.hn)
- Worldwide compliance with regulatory bodies such as CENELEC, ARIB, and FCC
- Support for IPv6 to allow internet-based energy management systems
- Mesh routing protocol to determine the best path between remote network nodes

Table 4.1 shows a comparison between PLC-G3 and PRIME in terms of performance.

**Table 4.1: Performance comparison between PLC-G3 and PRIME.**

	PLC-G3	PRIME
<b>Sampling frequency</b>	400 kHz	250 kHz
<b>OFDM</b>	<ul style="list-style-type: none"> <li>• <b>FFT size M</b></li> <li>• <b>Length of cyclic prefix <math>L_{CP}</math></b></li> <li>• <b>Window</b></li> <li>• <b>Subcarrier spacing Af</b></li> <li>• <b>Nº of carriers used (1-side)</b></li> </ul>	<ul style="list-style-type: none"> <li>256</li> <li>30</li> <li>Raised-cosine slope 8 samples</li> <li>1.65625 kHz</li> <li>36</li> <li>512</li> <li>48</li> <li>Non</li> <li>488 Hz</li> <li>97</li> </ul>
<b>Frequency range occupied</b>	35.9-90.6 kHz	42-89 kHz
<b>Max. Data rate</b>	33.4 kbps	128.6 kbps
<b>Forward error correction</b>	Reed Solomon code, convolutional code, repetition code	Convolutional code
<b>Interleaving</b>	Per data packet	Per OFDM symbol
<b>Modulation</b>	<ul style="list-style-type: none"> <li>• <b>Differential encoding</b></li> </ul>	<ul style="list-style-type: none"> <li>DBPSK, DQPSK</li> <li>In time</li> <li>DBPSK, DQPSK, D8PSK</li> <li>In frequency</li> </ul>

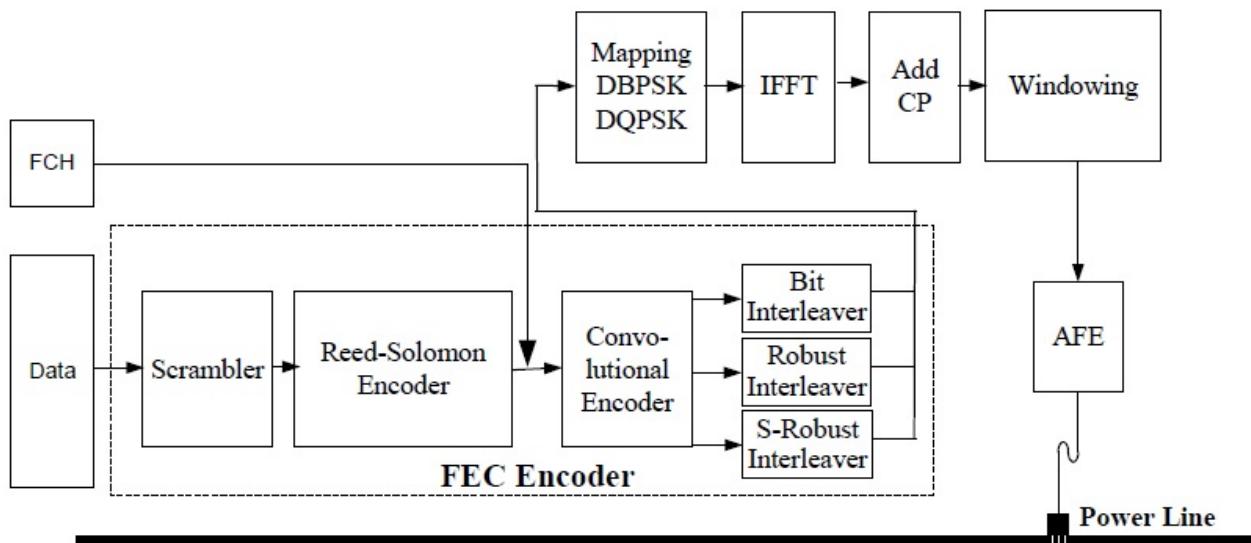


Figure 4.9: Block diagram of OFDM transceiver compliant with the PLC G3 Physical Layer Specification [38]-[39].

With the idea to unify the different standards on PLC there has been the creation of the IEEE P9101.2 that extends the G3 protocol to higher frequency inside the FCC. This standard includes technological advances, maintaining G3 and PRIME specifications. In the CENELEC band A, the frequency range is from 35.9 kHz to 90.6 kHz, which allows obtaining a data rate of 52.3 kbps using the same frequency sampling and FFT length features of G3. The provided modulations are 2-DPSK, 4-DPSK, 6-DPSK and 8-DPSK (and QAM).

The International Telecommunication Union -Telecommunication Sector (ITU-T) has developed the G.hnem specification for PLC in order to reach the same purposes that the 1901.2 group of IEEE is working for. CENELEC band A exploits frequency band from 35.9 kHz to 90.6 kHz using a sampling rate of 200 kHz and a FFT length of 128, reaching up to 101.3 kb/s. FCC transmits from 34.4 kHz to 478.1 kHz, with a sampling rate of 800 kHz and an IFFT length of 256, reaching up to 821.1 kb/s. The signal is modulated using 2-QAM, 4-QAM, 8-QAM, 16-QAM.

For an active distribution grid, there is the need to provide several technologies that implement the concepts that are becoming needed for the intelligent power grid to become a reality. The secure active electricity grid employs innovative products and services together with intelligent monitoring, control, communications, and self-healing technologies. In such networks, where electricity and information flow is bi-directionally, communications play a major role, and one of such technologies will be narrow-band PLC (NB-PLC).

The presence of NB-PLC, may allow novel services in smart electricity distribution networks such as demand side management, control of distributed generation and customer integration. Today NPLC is mainly used for AMI, where meters are required to be read in real-time, near real-time or a few times per day. Currently, meter reading occurs every 15 minutes. AMR systems can tolerate longer latencies even hours, so the use of PLC systems which is very susceptible to noise and power line interferences can be of use. It is worth mentioning some of the advantages and disadvantages of PLC depending on PLC technology (Table 4.2). In addition to AMR, NB-PLC can be used to restore faults in the network, where bidirectional PLC communications can facilitate faster and more efficient restoration of power.

Table 4.2: Advantages and drawback of PLC depending on PLC technology.

Technique	Advantages	Drawbacks
High-speed Narrowband PLC	<ul style="list-style-type: none"> <li>- Communication channel available</li> <li>- High medium penetration</li> <li>- Independency on a 3<sup>rd</sup> party</li> </ul>	<ul style="list-style-type: none"> <li>- Reliability depends on channel</li> <li>- Channel changing very stochastically</li> <li>- Short and medium coverage</li> <li>- Shared channel</li> </ul>
Broadband PLC	<ul style="list-style-type: none"> <li>- High throughput</li> <li>- Infrastructure is available</li> <li>- Independency on 3<sup>rd</sup> party</li> </ul>	<ul style="list-style-type: none"> <li>- Sensible to electromagnetic disturbances</li> <li>- short coverage</li> <li>- lack of standards</li> </ul>

Figure 4.13 describes the potential use of NB-PLC as active distribution grid enables (backhaul communication).

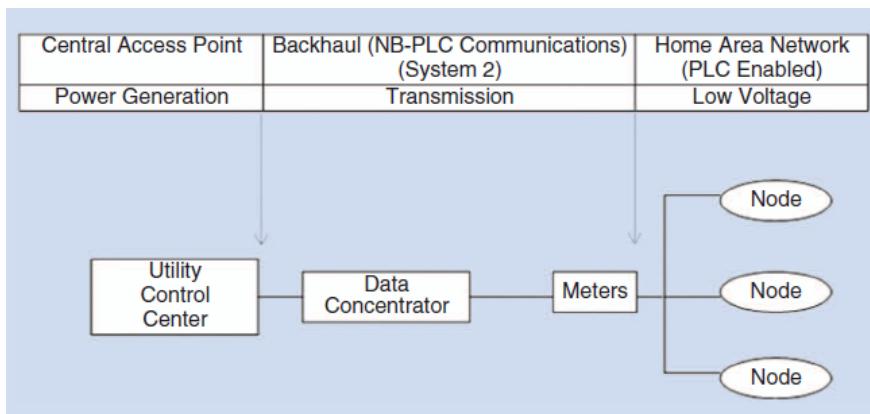


Figure 4.10: Architecture development to progress in PLC utility at distribution network level.

#### Standards referred to the power grid medium for PLC

Some standards are specific for the electrical specifications of the power grid that regulate the variability and conformity of any equipment that is attached into the power grid. Some standards are referred to the equipment that are energy generators. In all the cases for the active distribution network, there are several circumstances that will apply for the massive penetration of DERs or EV that may influence the medium for the PLC communications signals. Also frequency converters, DC choppers and inverters supplying loads like motors and welding machines cause problems. PLC signal has also reported to disturb lamps using light touch dimmers.

In the following plot there is a summary on some of the standards to be applied to the power grid connected devices, mainly to the PV devices as a typical use case. In this case, there are some manufacturers that provide equipment with limited performance, due to cost reduction.

#### UNE-EN 50160: Characteristics of the voltage supplied by the general distribution networks

This standard describes the main characteristics of the voltage supplied by a LV, MV and HV distribution network in normal conditions of exploitation. Related standards to this normative:

- EN 60664-1:2007: Isolation coordination of the equipment in the low voltage systems (grids). Part 1: Principles, requests and tests
- EN 61000-3-3: Limits for Voltage Fluctuations and Flicker
- IEC 61000-4-30: Electromagnetic compatibility (EMC) – Part 4-30: Testing and measurement techniques – Power quality measurements methods
- IEC 61000-2-8: Electromagnetic compatibility (EMC) – Part 2-8. Environment. Voltage sags and short interruptions in the public electrical supply grids, including statistical measurements.

Some standards are specific country by country. In this regards, every manufacture has to carefully perform the required tests in order to validate their equipment in accordance to the regulations required in the installation place. In that case, for a particular installation, if a PLC signal is also propagating, the type of fluctuations on the grid may vary, or may be subject to different types of limitations. Most of these limitations are defined for the mains frequency, or harmonic frequencies that are far away from the frequency band of interest from PLC signal, but they provide a limitation for all type of equipment that will be connected to the grid, in special requirements for DER units interfaced with the grid with their power electronics unit.

Some of the requirements presented in Table 4.3 are specific for inverters that are interconnected to the grid, and may pose some interference to the PLC signal, mainly due to the noise generated by such devices. In this regards:

- In Spain, for example for power higher than 5 kW, it is required to connect the devices including a power transformer with a voltage lower than 1 kV. Maximum installed power is lower than 100 kVA.
- In Germany, there is no limit for injected power while for power higher than 5 kVA transformers are required in a voltage grid of 400 V.
- In France a transformer is required for power lower than 250 kVA at 1kV grid.

**Table 4.3: Requirements for grid-connected inverters for Spain, Germany, and France.**

Requirements	Spain	Germany	France
Radiated emissions: EMC limits	EN 50082-1, EN 50082-2	EN 50082-1, EN 50082-2	EN 50082-1, EN 50082-2
Requirements for Power Factor	As close as possible to unity	In LV: $0.8 \leq fp \leq 0.9$	Reactive = 0.
Voltage operating range in AC	$0.85*Um \leq U \leq 1,1 Um$	VDE 0126: $0.85*Um \leq U \leq 1,1*Um$	VDE 0126: $0.85*Um \leq U \leq 1,1*Um$
Frequency operating range in AC	$50 \text{ Hz} \pm 1,0$	VDE 0126: $50 \text{ Hz} \pm 0,2$	VDE 0126: $50 \text{ Hz} \pm 0,2$
Voltage dips and short supply interruptions	IEC 61000-2-8		
Transient voltage	IEC 60664-1		

In addition to particular standards based on the different countries, there are international legislations that define operating limits such the ones done by the International Electrotechnical Commission (IEC). In particular here is presented a summary for the IEC 61000-2-2 related to the electromagnetic compatibility

(EMC). In particular part 2.2 relates to compatibility levels for low-frequency conducted disturbances. Since these have a high technical content, they are kept under constant review by the IEC.

### IEEE Standard for Low-Frequency Narrowband Power Line Communications for Smart Grid Applications

This standard specifies communications for low-frequency (less than 500 kHz) narrowband power line devices via alternating current and direct current electric low-voltage power lines (less than 1000 V) and medium-voltage (1 to 72 kV) through associated transformers in both urban and long-distance rural applications. It is especially suited for utility meter, grid automation, electric vehicle to charging station, and within home area networking. This standard is mainly suited for low data rate (500 kbps or less) long-range applications. Some of the normative references mentioned in the standard are summarized in Table 4.4.

**Table 4.4: Some normative present in the IEEE Standard for Low-Frequency Narrowband Power Line Communications for Smart Grid Applications.**

CENELEC EN 50065-1: (2011)	Signaling on low-voltage electrical installations in the frequency range 3 kHz to 148.5 kHz. <a href="http://www.cenelec.eu">http://www.cenelec.eu</a>
CISPR 22: (2008), 6 <sup>th</sup> ed.	Limits and Methods of Measurement of Radio Interference Characteristics of Information Technology Equipment
	Code of Federal Regulations, Title 47, Part 15 (47 CFR 15), Radio Frequency Devices.
IEEE Std 802.15.4 (2006)	IEEE Standard for Information technology—Telecommunication and information exchange between systems—Local and metropolitan area networks—Specific requirements—Part 15.4: Wireless Medium Access Control (MAC) and Physical Layer (PHY) Specifications for Low- Rate Wireless Personal Area Networks (WPANs).
	IEEE Standard for Local and metropolitan area networks—Part 15.4: Low- Rate Wireless Personal Area Networks (LR-WPANs)—Amendment 1: MAC sublayer
ITU-T.G.9903 (2012)	Narrowband orthogonal frequency division multiplexing power line communication transceivers for G3-PLC networks
ITU-T G.9904 (2012)	Narrowband orthogonal frequency division multiplexing power line communication transceivers for PRIME networks

The information contained in such standards makes reference to the PHY and MAC layers of the OSI on how to adopt the PLC system for communication through the power line, structuring the frames and modulation to optimize the information transfer in the different countries.

An interesting feature that is detailed in the standard is the creation of the power line channel models. Such models can be represented analytically, so it is possible to include the PLC system in the channel modeled and validate its performance prior to field real test.

Also of interest for this standard is the description of the different noise sources that contribute in the NB-PLC frequency bands, especially when the PLC signal must operate in noise domains such as the ones where very much penetration of DER are integrated into the power grid. There are five main categories that the noise sources are detailed into [40]:

1. **Colored background noise:** with a decaying PSD that decreases with frequency. This noise is the agglomeration of various noise sources with low power.
2. **Narrowband noise:** modulated amplitude sinusoids caused by ingress of broadcast stations.
3. **Periodic impulsive noise asynchronous to the mains frequency:** mostly caused by switched power supplies. Typically, the period of this noise varies between 50 kHz and 200 kHz.
4. **Periodic impulsive noise synchronous to the mains frequency:** caused mainly by switching rectifying diodes. These impulses have a short duration with decreasing PSD.
5. **Asynchronous impulsive noise:** caused by agglomeration of switching transients in PLC networks. Their occurrence is random and can have values as high as 50 dB above the background noise.

In particular, in the frequency band of interest between 45 kHz to 450 kHz, the dominant source is spectrally shaped cyclostationary noise synchronous to mains [41].

From this standard some measurements are presented, based on a neighborhood area that includes several sub-stations with their feeders and distribution to the end-user, showing the narrow band interferences. LV sites experience noise that has periodic properties that are synchronized with the alternating current mains with a period of TAC/2. In particular, the noise traces exhibit a periodic envelope (power) with random instantaneous amplitude (Figure 4.14).

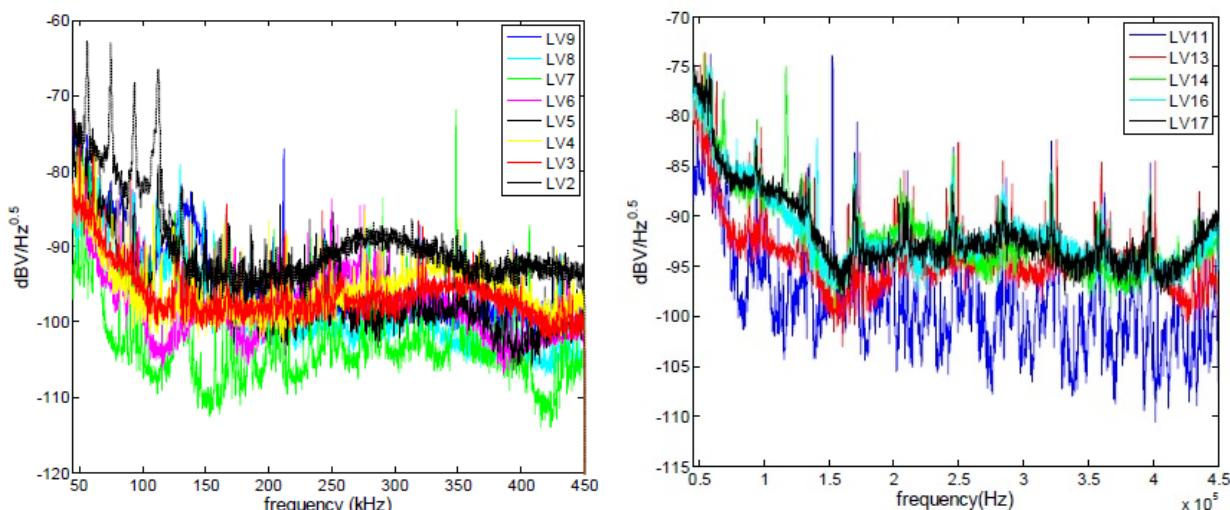


Figure 4.11: Monitoring of different feeders from 3 substations: LV2 to LV4: from Substation 1; LV5 to LV8: from substation 2 and LV9 to LV17 from substation 3.

#### IEEE Standard for Power Line Communication Equipment – Electromagnetic Compatibility (EMC) Requirements – Testing and measurement methods

EMC effects over the PLC signal are of major importance, for two reasons, the media that propagates PLC signal can act as antenna (open conductor) and radiate, and also other radiations can couple to such cables and affect the PLC device. That implies that PLC signal emissions must be compliant with current EMC limits. Some considerations to take into account when dealing with EMC.

- IEC publications from bodies such as CISPR, which are elaborated in international committees and are usually adopted as national laws.
- Whenever CISPR standards are not nationally adopted, the gaps are filled by laws from the respective national regulatory authorities.

For very low-speed PLC, a frequency range from 3 to 148.5 kHz is available, according to standard EN50065, which has been in force since 1991. The frequency range is separated into A, B, C, and D bands with detailed transmission signal amplitude limitations and dedication for use. Within the C band, a carrier sense multiple access (CSMA) protocol is specified. Due to the very restricted bandwidth, maximum data rates are in the range of 100 kb/s.

Even when this standard is for broadband PLC communication systems, it makes reference to narrow band standards and regulations that are of interest when going to understand the different limitations of EMC for different frequency bands and regions. In general, the regulations for EMC are making reference for radiations that are produced in the 30-1000 MHz band, going even lower from the 150 kHz to 30 MHz band in the specified cases. These are the frequencies that shall be paid attention in case of the equipment (meter) being susceptible to generate unwanted radiation or being susceptible to receive such radiation, so prone to mal-function of bad-operation in such environment.

**Table 4.5: List of standards dealing with PLC communications in the radio frequency bands affecting with EMC.**

ANSI C63.4	American National Standard for Methods of Measurement of Radio-Noise Emissions from Low-Voltage Electrical and Electronic Equipment in the Range of 9 kHz to 40 GHz
CISPR 11	Industrial, scientific and medical (ISM) radio-frequency equipment—Electromagnetic disturbance characteristics—Limits and methods of measurement
CISPR 16-1-4 CISPR 16-2-1 CISPR 16-2-3	Specification for radio disturbance and immunity measuring apparatus and methods—Part 1-4: Antennas and test sites for radiated disturbance measurements Part 2-1: Conducted disturbance measurement Part 2-3: Radiated disturbance measurement
CISPR 22	Information technology equipment—Radio disturbance characteristics—Limits and methods of measurement.
CISPR24	Information technology equipment—Immunity characteristics—Limits and methods of measurement.
EN 61000-3-2	Electromagnetic compatibility (EMC)—Part 3-2: Limits—Limits for harmonic current emissions (equipment input current ≤ 16 A per phase).
EN 61000-3-3	Electromagnetic compatibility (EMC)—Part 3-3: Limits of voltage changes, voltage fluctuations and flicker in public low voltage supply systems, for equipment with rated current ≤ 16 A per phase and not subject to conditional connection
EN 61000-3-8	Electromagnetic compatibility (EMC)—Part 3: Limits—Section 8: Signaling on low voltage electrical installations—Emission levels, frequency bands and electromagnetic disturbance levels
EN 61000-4-2 EN 61000-4-3 EN 61000-4-4 EN 61000-4-5 EN 61000-4-6 EN 61000-4-8 EN 61000-4-11	<ul style="list-style-type: none"> <li>• Electromagnetic compatibility (EMC)—Part 4-2: Testing and measurement techniques—Electrostatic discharge immunity test</li> <li>• Radiated, radio-frequency, electromagnetic field immunity test.</li> <li>• Electrical fast transient/burst immunity test.</li> <li>• Surge immunity test</li> <li>• Immunity to conducted disturbances, induced by radio-frequency field.</li> <li>• Power frequency magnetic field immunity test.</li> <li>• Voltage dips, short interruptions and voltage variations immunity tests</li> </ul>

As an example of this standard, it specifies the measurement method for frequencies below 30 MHz, using the general equipment setup and test configuration, following the measurement procedures in CISPR 16-2-3. For frequencies below 30 MHz, an active or passive magnetic loop shall be used. Field strength in dB $\mu$ A/m is converted to dB $\mu$ V/m by adding 51.5 dB according to the formula  $\text{dB}\mu\text{V}/\text{m} = \text{dB}\mu\text{A}/\text{m} + 51.5 \text{ dB}$ .

So the use of PLC opens new technical challenges such the ones described above for the electromagnetic compatibility (EMC), both for electromagnetic emission (EMI) and electromagnetic susceptibility (EMS). Sharing the same cable as the power signal, which is not prepared for communications, that means that is it not shielded so the signals can interfere with other devices connected to the grid, behaving the media as an antenna that generate radiated disturbances in the same frequency bands.

#### 4.2.2 Existing protocols for Communications in support of the automation system

This subsection describes the existing communication protocols and it is intended to investigate which of them can be reused in the IDE4L in support of the automation architecture.

The monitoring, control and automation of power distribution network is currently implemented through SCADA (supervisory control and data acquisition) which generally consists of a master terminal (at a DSO's control center) and a large number of remote terminal units (RTUs) located at geographically dispersed sites. RTUs collect network measurements and deliver commands to control devices via heterogeneous and un-standardized communication channels with diverse physical medium (e.g. leased digital fibers, private pilot cables, public switched telephone network (PSTN) lines, radio frequencies, and satellite and mobile cellular networks). The main sets of protocols used in this context are Modbus, IEC 104, IEC 101 and the corresponding protocol for the IEC 61850.

##### MODBUS

Modbus is an open communication protocol designed by Modicon in 1979 that was originally used for its PLCs. The communications are based on a master-slave structure, in which the master makes requests to the slaves and they respond to the master. These types of communications are known as *unbalanced*.

Modbus allows the communication of about 240 devices in the same network, using a different address to identify each device.

Generally, there are two transmission ways when the Modbus protocol is implemented:

- Modbus Serial → It usually uses RS-485 or RS-232 for the data transmission.
- Modbus TCP → The data transmission is performed using TCP/IP packets.

Since Modbus is a protocol designed in 1979, it does not provide security against unauthorized commands or interception of data, so it can be vulnerable to external attacks.

##### DNP3

DNP3 is an industrial protocol designed by Westronic in 1993, which is widely used in the electrical sector, with a large presence in the United States and Canada, and a smaller presence in Europe where protocols like IEC 60870-5-101 and 104 enjoy of greater popularity.

This protocol is *balanced*. That means that the communications may be started either, from the master station or from the slave station. DNP3 allows initiating the communication from the controlled station depending on the alteration of certain information (unsolicited response).

The DNP3 protocol is designed on the EPA model, in which some of the layers of the OSI model are used:

- Application Layer: This layer processes the data fragments that arrive from the transport level, to obtain the control and monitoring information that is encapsulated. Among the services provided by this level, they are included the writing and reading of the values, the selection and execution of controls, etc. The function code is used to indicate which operation should be performed at this level.
- Transport Layer: This standard allows the transmission of large blocks of structured data, dividing the ASDU of the application layer into TPDUs.
- Data-Link Layer: The link layer allows a secure data transmission across the physical medium. This layer is responsible for the transmission of a data group called frame, which will be analyzed later. The main functions that provide this level are flow control and error detection.
- Physical Layer: The physical layer is comprised of the physical media over which the protocol is transmitted. It includes the physical interface characteristics, in terms of electrical specifications, timing, ping-outs, etc. One of the most used electrical interfaces for this protocol is the 10/100BASE-TX through a RJ45 connector.

### ***IEC 60870-5-104 and 101***

The IEC 60870-5-104 is an international standard, released in 2000 by the IEC and based on IEC 60870-5-101. This standard limits the types of information and the configuration parameters defined in IEC 60870-5-101, that means that not all functions defined in the IEC 60870-5-101 are supported in the IEC 60870-5 - 104. This protocol is mainly used for SCADA systems in electrical engineering and power system automation applications.

The IEC 60870-5-104 protocol is a balanced system, which means that the slave can start the communication without the master request. In addition this protocol is based on TCP/IP.

Following, the data types that can be sent using this protocol are listed:

#### From slave to master:

- Single Point (SP) → {0,1} → 1 bit.
- Double Point (DP) → {0,1,2,3} → 2 bit.
- Measures (ME):
  - ME\_A → Integers, 16 bits.
  - ME\_B → Integers, 16 bits.
  - ME\_C → Floating, 32 bits.
- IT → Energy (32 bits).

#### From master to slave:

- Single command (SC) → {0,1} → 1 bit.
- Double command (DC) → {0,1,2,3} → 2 bit.
- Set Point (SE):
  - SE\_NA → Integers, 16 bits.
  - SE\_NB → Integers, 16 bits.
  - SE\_NC → Floating, 32 bits.

One of the most important features of these protocols is the time tag, which records the instant (date and time) in which a change occurs.

Another aspect to consider in these protocols is the dead band (Smoothing), which records the instant in which the data are sent. This band can be static or dynamic (%).

- Static → Fixed interval (e.g. 5 Amp).
- Dynamic → Percentage (e.g. 0,5%).

To send measures there are three cases:

1. Spontaneous Rate: The dead bands are respected.
2. Periodic Cycle: Scheduled by the user.
3. General Interrogation: It upgrades or reads the process image (last values that has the installation after, for example, a reboot). It reads all data except analog measurements.

### IEC 61850 Suite

This standard defines communications within transmission and distribution substations for automation and protection. It is being extended to cover communications beyond the substation to integration of distributed resources and between substations.

### IEC 61850 Models and the Common Information (CIM) Model

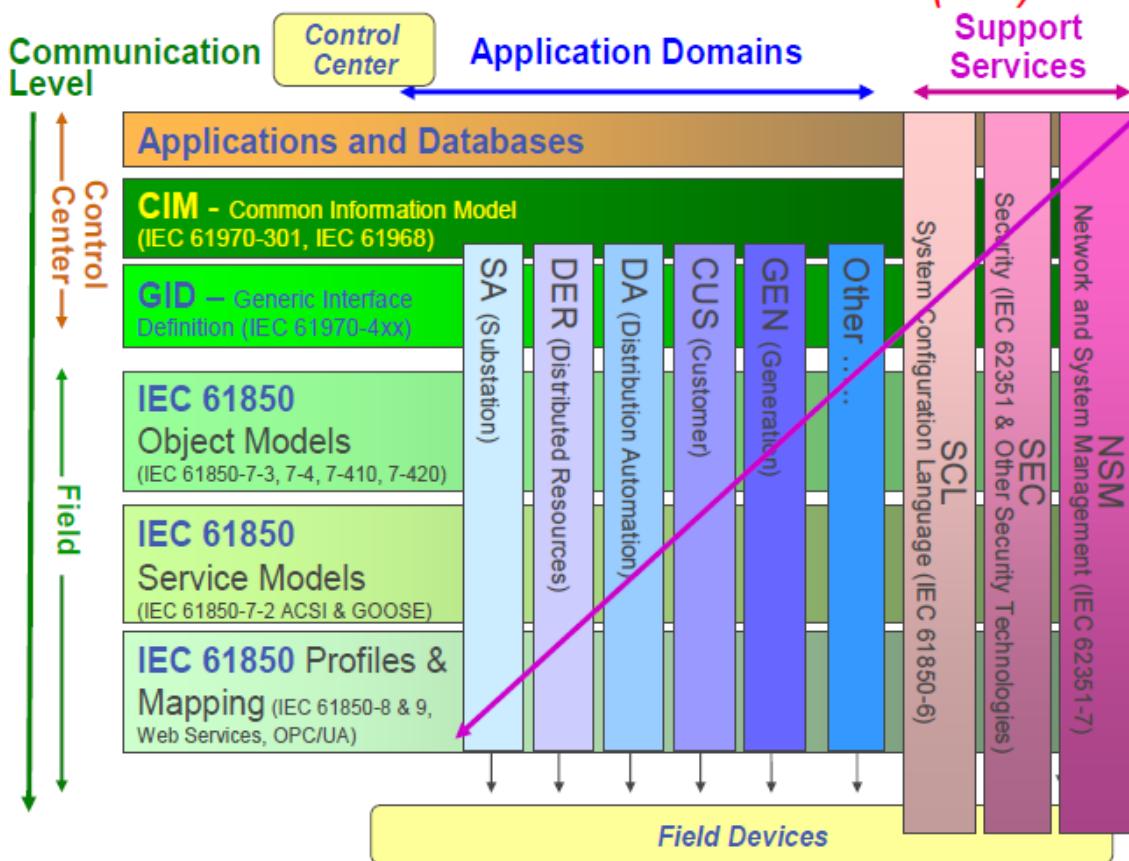


Figure 4.12: IEC 61850 modelling and connections with CIM and other IEC TC 57 models.

Vertically, different information models are shown:

- substation automation (IEC 61850-7-4),
- large hydro plants (IEC 61850-7-410),

- distributed energy resources (DER) (IEC 61850-7-420),
- distribution automation (under development),
- advanced metering infrastructure (as pertinent to utility operations) (pending).

The stated scope of IEC 61850 was communications within the substation. The document defines the various aspects of the substation communication network in 10 major sections as shown in Table 4.6.

**Table 4.6: IEC 61850 suite divided into its 10 parts.**

Part #	Title
1	Introduction and Overview
2	Glossary of terms
3	General Requirements
4	System and Project Management
5	Communication Requirements for Functions and Device Models
6	Configuration Description Language for Communication in Electrical Substations Related to IEDs
7	Basic Communication Structure for Substation and Feeder Equipment
7.1	- Principles and Models
7.2	- Abstract Communication Service Interface (ACSI)
7.3	- Common Data Classes (CDC)
7.4	- Compatible logical node classes and data classes
8	Specific Communication Service Mapping (SCSM)
8.1	- Mappings to MMS (ISO/IEC 9506 – Part 1 and Part 2) and to ISO/IEC 8802-3
9	Specific Communication Service Mapping (SCSM)
9.1	- Sampled Values over Serial Unidirectional Multidrop Point-to-Point Link
9.2	- Sampled Values over ISO/IEC 8802-3
10	Conformance Testing

## 4.3 Architecture developments to be done in Monitoring Measurements

### 4.3.1 Architecture developments required for monitoring distribution grid dynamics

#### *Introduction*

Current power systems are operated closer to capacity limits and therefore they are weakened and sometimes even overloaded. Due to this situation, stability margins are reduced. The optimization of the infrastructures and the required quality of supply implies a need of increasing the efficiency of the system. Phasor Measurement Units (PMUs) are control, protection and measurement equipment, which provide this efficiency by means of defining technical specifications adequate to each application, and based on standard IEEE C37.118.

PMUs provide a simplification on the way to represent AC, using a graphical representation for their module and phase instead of differential equations (Figure 4.16).

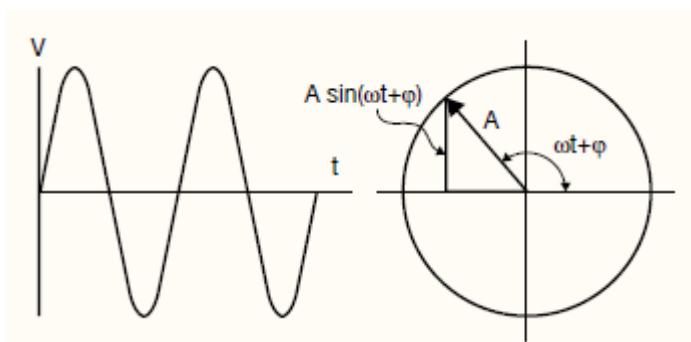


Figure 4.13: Phasorial representation.

These measurements, based on Global Positioning Systems (GPS), help to avoid synchronization losses, and in the end, supply interruptions. The GPS synchronization signal is sent to the units, and correlates the current and voltage signals sampled in a substation, as shown in Figure 4.17. The phasor measurements are sent, associated with a time instant, in a proper format defined in the aforementioned standard, so they can be concentrated and sent to a central system, or shared between PMUs for a decentralized management.

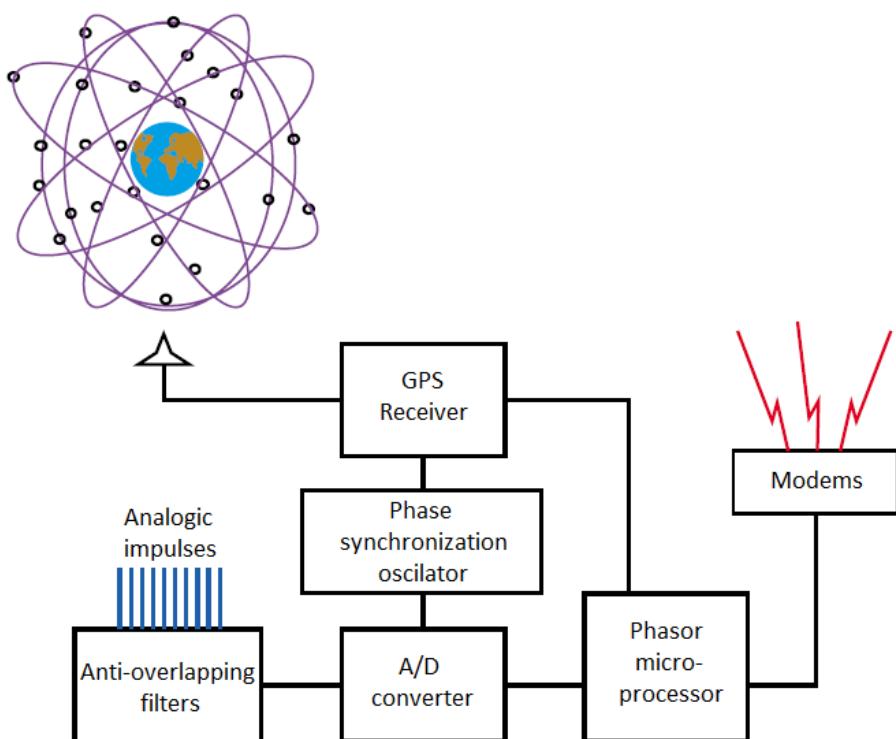


Figure 4.14: PMU diagram (Source: ABB).

These set of data provides an accurate base to develop high-level new supervision, protection and control techniques for power grids.

PMUs also allow a change in the current state estimation. Nowadays, state estimation procedures are based on non-synchronized measurements, so a dynamic analysis of the power grid state is not feasible. With the introduction of PMUs, a wide range of studies are possible, and DSOs can carry out advanced real-time analysis of the static and dynamic events produced in the power grids.

### *Integration of PMU in the automation architecture*

Regarding PMUs, current technology is very limiting for distribution networks, where there are stricter requirements on the measurement devices due to the relevant characteristics, such as phase unbalance, presence of DC current components, noise and harmonics, etc., particularly in LV distribution substations. The integration of PMU measurements in the architecture requires developing techniques for data processing (filtering, bad data handling, etc.) that enable the merging with traditional measurements into control center functions such as state estimation. This integration may require the extension of existing standards, particularly the IEC61850. Monitoring must also address special conditions linked to the presence of the DER, as unbalance in the LV distribution and presence of DC current components due to single-phase grid-connected inverter applications. Figure 4.18 illustrates architecture developments on communication protocols required for integration of PMU in the automation architecture.

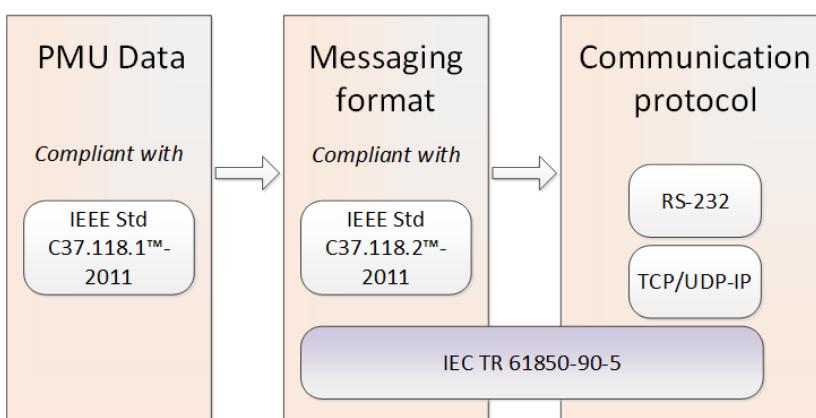


Figure 4.15: Integration of PMU technology via different standard protocols such as IEC61850 and C37.118.

### *PMU data processing architecture*

As mentioned in the previous section, techniques are required for extracting data out of both PMU and traditional measurements that are polluted by noise, measurement errors and harmonics, particularly in LV distribution substations. Consequently, it is required to process and harmonize instantaneous time-stamped PMU data with discrete unsynchronized traditional measurements for each monitoring function. Different measurements coming from identical locations should be also managed and coordinated through different methods for harmonization. Figure 4.19 illustrates architecture developments required for implementing these techniques. Data from substations collected from PMUs are concentrated and verified using a data concentrator, or they are interchanged between local units in order to carry out protection and control functions in a decentralized way. Each of the hardware shown below can sit either in secondary substation or in primary substation or at DSO, depending on the nature of the monitoring function. This concept will be better explained in the next section.

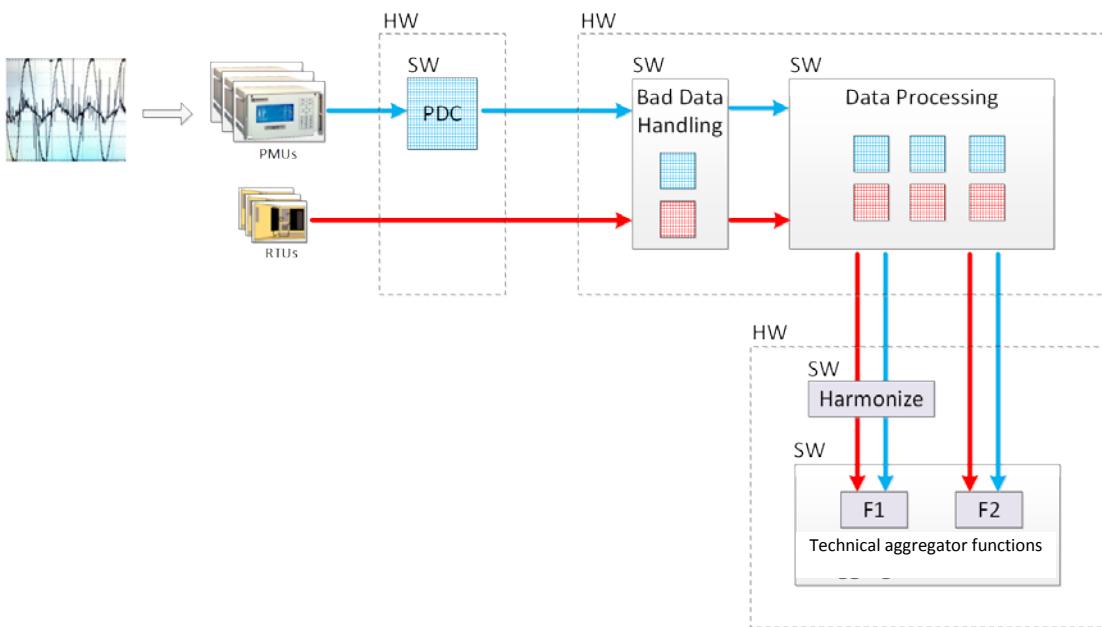


Figure 4.16: Architecture development needed for PMU data processing techniques.

### Architecture for TSO/ Technical Aggregator Interaction

As implied in the previous section, depending on the nature of the monitoring function, different architecture (shown in Figure 4.20) is required for TSO/ Technical aggregator interaction. In “Partially centralized/distributed” and “Distributed peer-to-peer” architecture, each technical aggregator sits at a primary substation and communicates with TSO, whereas in “Completely centralized” architecture, a super technical aggregator sitting at DSO exchanges the aggregated data with TSO.

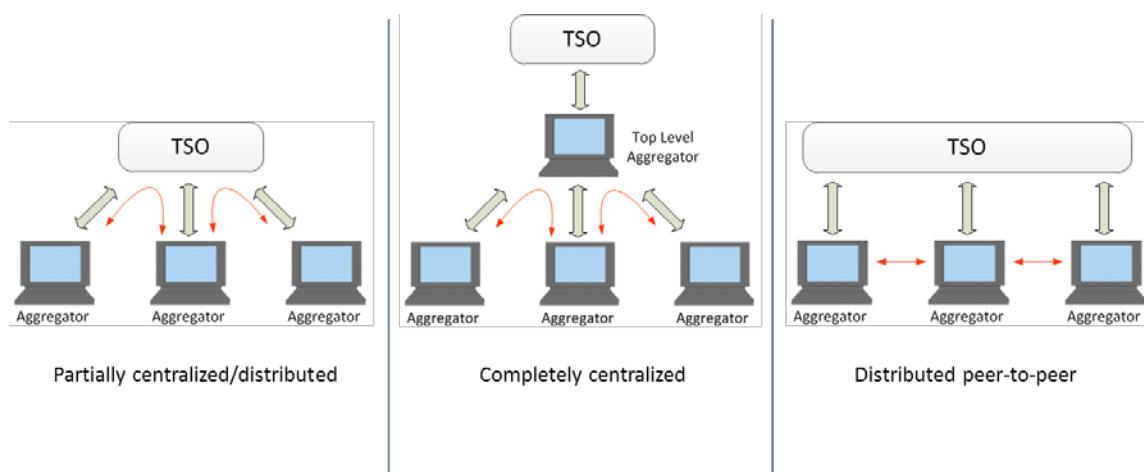


Figure 4.17: Architecture development needed for TSO/Technical aggregator Interaction.

### 4.3.2 Architecture developments required for monitoring power quality indicators in distribution networks

The term power quality refers to several technical issues including interruptions of power supply, under and over voltages, voltage sags, as well as other waveform distortions as voltage dc offsets, harmonics, notching, noise, flicker and frequency variations. Such power quality issues could provoke numerous technical problems such as possible damage and reduced lifetime of connected equipment, interference in communications and excessive power losses, amongst other several effects.

For these reasons, minimum power quality levels are principal for ensuring the proper power system management and stability. Accordingly, international standards define minimum threshold levels for power quality to ensure proper network operation, consumer's protection and also as a requirement for the grid connection of generation facilities.

There are several international standards and regulations on power quality [43]-[47]. The international standard "IEC 61000-2-2: environment – compatibility levels for low-frequency conducted disturbances and signaling in public low-voltage power supply systems" can be considered as a reference. This standard covers those disturbances in the range from 0 kHz to 9 kHz (also including an extension up to 148.5 kHz for mains signaling systems). The standard is applicable to low voltage networks, so covering 50-60 Hz 420 V – 690 V one phase and three phase grids. This way, it totally fits with the scope of the IDE4L project. The standard serves to determine and evaluate power quality levels at the point of common coupling of equipment with the low voltage electrical network. This means that, for instance, it can be applied to check the limits for electromagnetic disturbance emission into public power supply systems while developing new electrical equipment. In the other way around, it can serve to check the immunity limits to electromagnetic disturbances for protection of equipment connected to the network [42].

In the field of renewables generation, chapter 21 of IEC 61400 and also the European EN standard 50160, amongst others, aim to determine minimum threshold levels for electromagnetic disturbances provoked by wind turbines at their grid connection. In fact, the power generated by renewable-based power plants is neither constant nor controllable due to the stochastic nature of wind and solar irradiation, so the power quality of distribution electrical networks with high penetration of renewable generation can be compromised. These regulations impose limits in slow and fast voltage variations in distribution networks (in the range from a few seconds up to several minutes). Fast voltage fluctuations can be provoked by the variability of power output of wind turbines and photovoltaics. The topology of the wind turbine (power converters, electrical machine, filters, etc.) and the nature of wind (turbulences, interruptions, changes in direction and so on) can affect fast voltage fluctuations in weak or isolated networks with high penetration of distributed generation. In turn, fast voltage variations can provoke excessive flicker levels and this is the particular power quality index to be addressed in the IDE4L project (Use Case "Power quality in LV/MV lines with power electronic-based systems").

Flicker is a subjective sensation of visual instability provoked by fast fluctuations in light stimulus. It can cause annoying luminance changes in lamps in the frequency spectrum from 0.05 Hz to 35 Hz. Flicker emission is bounded by the international standards for protection of people and electrical equipment. For flicker measurement, IEC 61000-4-15 describes the so-called flicker meter. This device provides two flicker indices: short and long term flicker severity. The short-term flicker severity at the point of connection of a wind park is bounded at 0.35 by IEC 61000-3-7. The maximum admissible level for long-term flicker is limited at 0.25. Figure 4.21 presents a schematic of the flicker meter as defined by IEC 61000-4-15 standard.

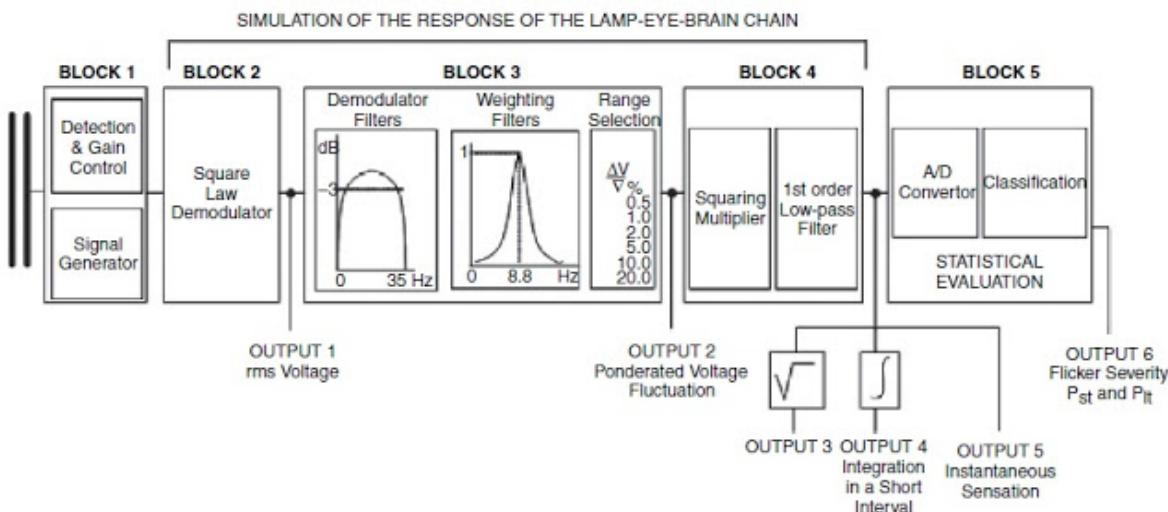


Figure 4.18: Flicker meter scheme according to IEC 61000-4-15 standard.

The determination of short and long-term flicker levels require precise measurement of voltage waveform at certain point of the network for at least 10 minutes (short-term flicker) and up to 2 hours (long-term flicker). Then, these measurements have to be processed and sent to the network operator for supervision.

In the IDE4L project (use case: “Power quality in LV/MV lines with power electronic-based systems”) the aim is to use voltage measures to determine flicker levels and permit an “ancillary service provider” to perform correction actions so as to ensure not to overcome the threshold levels defined by international standards in regard of power quality. This ancillary service provider needs to acquire voltage measures at its point of connection, so locally, to perform an active voltage filtering for flicker mitigation. Although this ancillary service provider, or equipment, could basically work autonomously, it has to be equipped with communication devices to inform network operator about flicker mitigation and facilitate the economic valorization of the provided service. The determination of the best communication devices to enable this communication between the “ancillary service provider” and the network operator is to be addressed. Also, best technologies to enable the “ancillary service provider” to successfully measure voltage levels at its point of connection for processing and performing active filtering for flicker mitigation are to be selected.

#### 4.3.3 Other architecture developments in monitoring measurements

Within the present deliverable the focus was mostly on PMU and PQ as far as monitoring techniques. However, the IDE4L project aims at developing other topics in monitoring measurements. The following topics will be detailed in deliverable D3.2:

- large-scale distributed monitoring system,
- peer to peer communication using IEC61850 for FLISR,
- PSDXP and SSDXP technologies (databases),
- basic methods for data exchange (e.g. client-server for meter reading and control commands), and
- IEC61850+CIM data model for DXP.

## 4.4 Architecture developments to be done in Control Centers

### 4.4.1 Introduction

In order to keep the network integrity in presence of high amount of DER, new control strategies will be required. Currently, the distribution network is under an open loop control where human operators make decisions. Networks become smart when the control is performed automatically through retrofit, by the means of gathering data, communicating and processing the information collected, and finally adjusting the network to possible variations that take place during real-time operation.

A smart grid requires the use of dynamic systems to control voltage, active and reactive dispatching, demand response actions, and a liberalized energy market for producers and consumers. All these will be supported by a massive use of information, communication and control technologies.

Smart grids take advantage of on-line control and communication possibilities to improve the system reliability. In this context, information technologies, control systems and advanced communications will be essential to realize the potential that new technologies offer to transform the electric power systems into a smart grid. Smart grids need ICT infrastructure to enable fast two-way communications between DSOs and network users, as well as between network components.

New technologies will allow supervising and controlling the magnitudes that define the network status and its service conditions in every moment: voltage, current, frequency and phase shift. Protection, control and metering equipment, active network management and distributed storage options will help to achieve the efficient smart grid concept.

Current control centers have the need to adapt to the changes that power grids are experimenting:

- Great penetration of DG at LV level,
- Substations more frequently in reverse power flow (DG),
- Millions of measuring points,
- Electric Vehicles,
- Demand response.

Hence, the objectives for a Control Center to support smart functionalities are the following:

- Network monitoring and operation: network reconfiguration for congestion managements and fault restoration;
- Forecasting and State estimation: collecting information and alarms from the network, and providing the most probable state of it;
- Power and Voltage control: collecting information, calculating and sending set-points to the equipment, remote control of the equipment, scenario simulation, storing historic information;
- Generation: data collection, energy balance, scenario simulation, storing historic information.

### 4.4.2 Architecture developments required for control centers

The architecture developed in control centers must integrate all the systems necessary for a smart grid deployment:

- AMI control center,
- DER control center,

- DMS,
- EV control center.

Each one of these systems applies to a different asset of the network, as it is shown in Figure 4.22.

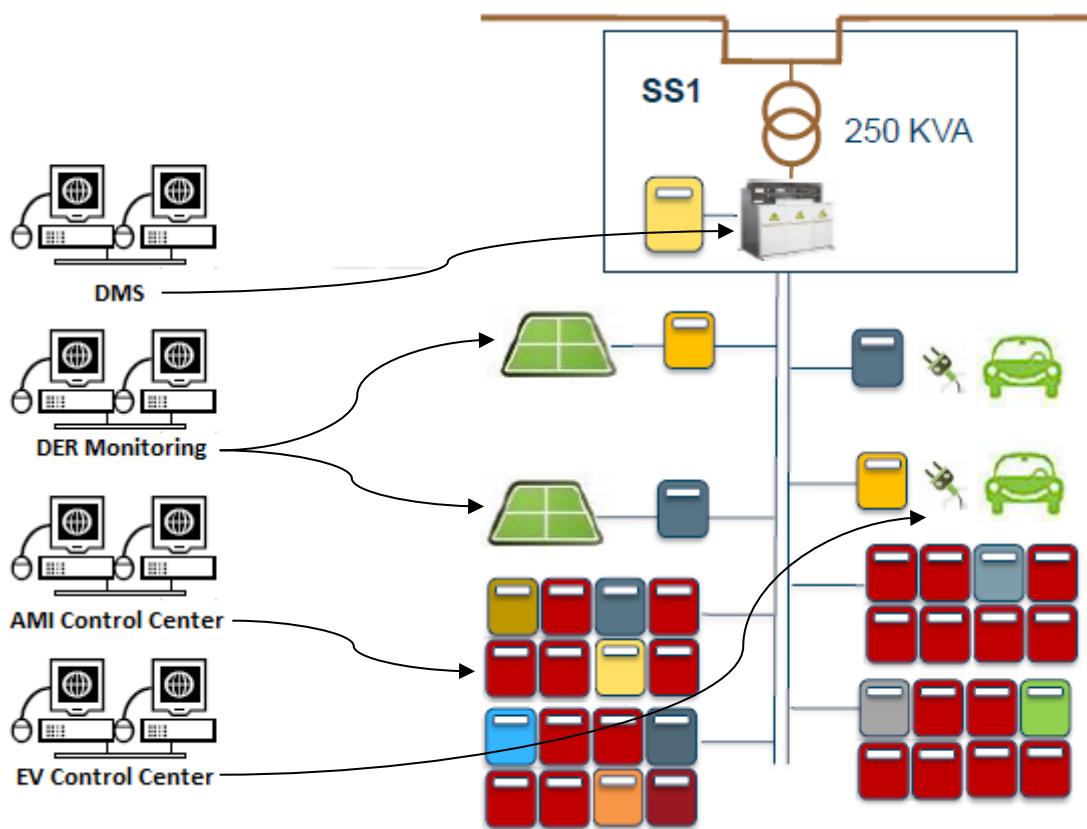


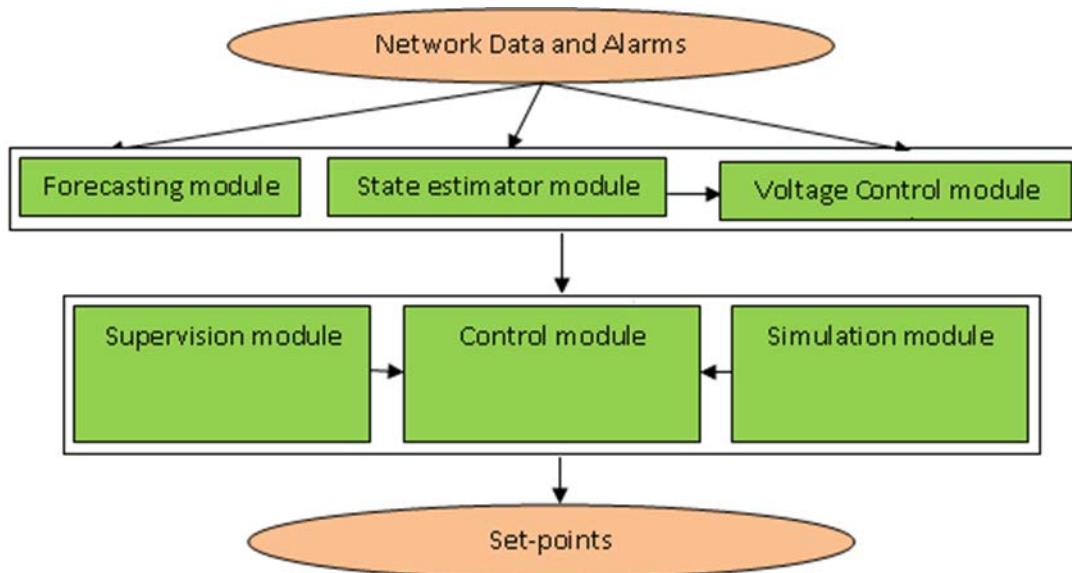
Figure 4.19: Systems for smart grid deployment.

In order to join all these separate functionalities into a whole system, a structure is proposed. A generic architecture for a Control Center will embrace the following modules:

- Monitoring module, which receives all the information from the network (data and alarms), adapts the format of the different sources, and serves as an input for the forecasting, state estimator and the voltage control modules.
- Forecasting module, which provides load demand forecast at different consumption levels (individual customers' meters or SS concentrator). In addition, this module will give short-term DER production forecast based on historic production data and weather predictions (solar irradiancy, temperature, wind) from local meteorological agencies. Forecaster outputs (load consumption and DER production) will be useful for the state estimator module and DMS algorithms.
- State estimation module, whose output is the most probable state of the network, based on historic and current data.
- Power and Voltage control module, which executes an Optimal Power Flow algorithm and obtains the optimal status of the network, and the necessary set-points to reach this status. This Power Flow algorithm can be optimized based on different criteria: minimizing losses, minimizing costs, congestion management, optimizing quality of the signal, etc.

- Simulation module, allowing the operator to know which will be the behavior of the network once the set-points are applied, changing the inputs from supply and generation, etc. The operator can set different scenario, and test them before acting.
- Supervision module, which allows the operator the visibility of the network, and the results of state estimation and simulations.
- Control module, which helps defining the control actions to be carried out, and generates the corresponding set-points.
- Integration with other systems.

The structure of the Control Center can be represented as in Figure 4.23.



**Figure 4.20: Structure of a Control Center.**

The aforementioned architecture can be supported by different standards:

- IEC 61850, a standard for the design of power station automation, is a part of the International Electrotechnical Commission Technical Committee 57 (TC57), whose main parts covers the system management, communication requirements for functions and devices, basic communication structure for substation and feeder equipment, or configuration language for communication in electrical substations related to IEDs.
- IEC60870-5-101 is a standard for telecontrol, teleprotection and communications, commonly used in electric power systems. IEC60870-5-104 protocol is an extension of 101 version, with some changes in transport, network, link and physical layer (e.g., it uses TCP/IP interface to connect LAN).
- CIM: IEC61970 and 61968: the IEC 61970 series of standards deals with the application program interfaces for energy management systems (EMS). Concretely, part 3 corresponds to the Common Information Model (CIM), where a common vocabulary and basic ontology for aspects of the electric power industry are defined. IEC 61968 extends the CIM to meet the needs of electrical distribution networks, where related applications include distribution management system, work management system, supervisory control and data acquisition system, network information system, customer information system, meter data management system, planning, geographic information system, asset management, customer information system, etc.

As information comes from different sources to the control center, an integration system is required to optimize data management and reduce redundancy, by a global treatment of the information. Several integration architectures can be defined [55]:

- Point to point integration: direct connection between two systems. This is the simplest structure and it is widely applied. However, if the number of systems is high, a more scalable solution is needed.
- Enterprise Application Integration (EAI): the connection between systems is performed by a set of tools and procedures, which manages this exchange of information. It reduces the number of connections, and it is more scalable. In contrast, this is a more complex structure, and harder to maintain.
- Enterprise Service Bus (ESB): it is an evolution of the EAI with a distributed nature, meaning more dynamic, and based on web technologies.

In order to implement these architectures, different integration technologies can be used:

- Service Oriented Architecture (SOA): it is a design pattern, implemented by means of using web services to define communication between service providers and consumers.
- Web services: software systems supporting interoperable machine-to-machine interactions over a network.
- Extensible Markup Language (XML): it is the most common data exchange format on the Internet, creating structures with the presented data, marking information with tags and forming hierarchical structure for the data.
- Simple Object Access Protocol (SOAP): it is a protocol based on XML, which is designed over Hypertext Transfer Protocol (HTTP).
- Web Service Description Language (WSDL): it describes interfaces between solutions, and provides users with a contact point to connect with the service.

Regarding the interfaces to outsourced and external services, there are different methods to create the service contract for the integration between the management system and the information system. However, all of them need the CIM profile to be presented in a XML schema format.

- IEC CIM: generic WSDL
- IEC CIM: strongly-typed WSDL
- Generating WSDL
- Service first

## 4.5 Conceptual Semantic Model

Before explaining the scheme, it's worth recalling the meaning of the word 'semantic' and 'model' and their role in Engineering. The Cambridge dictionary defines 'semantics' as *the study of meanings in a language*, while the adjective 'semantic' means that the subject *is connected with the meanings*. The Oxford dictionary defines a 'model' as *a simplified description, especially a mathematical one, of a system or process, to assist calculations and predictions*.

According to these definitions, a 'semantic model', is a simplified description of a system – in this specific case the automation architecture of the IDE4L project – which is used to clarify the meaning of the elements composing the architecture itself.

Figure 4.24 was built by using the UML notation, where:

- each box represents a class,
- each line between two classes expresses that they are somehow related,
- numbers at the ends of the lines express the cardinality of the relation, e.g. 1-0..\* means an object of the type class A could be related to 0, 1 or many objects of the type class B, while an object of the type class B is related to 1 and only 1 object of the type class A.

To be more accurate, Figure 4.24 provides a high-level description of the architecture, i.e. it contains only the most relevant bricks composing the architecture, leaving all the details to further schemes, which will be presented in Deliverable 3.2. This scheme mainly focuses on actors of the electricity supply chain (e.g. Transmission System Operator, Market Operator, etc.) and provides some details about the structure proposed by the project for managing the distribution grid, by “splitting” the Distribution System Operator (DSO) in more than one class.

The main classes highlighted in the scheme are:

- DMS – Distribution Management System: is the abstract representation of the DSO’s control center where the software for managing the grid is present.
- SAU – Substation Automation Unit: represents a new unit to be installed in primary and secondary substations to manage the distribution network according to a hierarchical control approach.
- IED – Intelligent Electronic Device: is a generic electronic device used for monitoring, controlling or protecting the distribution grid, a microgrid or the transmission grid.
- SEN – SENSor: is a generic sensor used to monitor the status of the grid e.g. a voltage transducer, a current transducer, etc.
- ACT – ACTuator: is a generic actuator used to change to status of the network e.g. the tap changer of a transformer, a switch, etc.
- TSO – Transmission System Operator: is the manager of the transmission network.
- MO – Market Operator: matches all the bids in the market and decides the power traded by the commercial aggregator in each period of the next day.
- CA – Commercial Aggregator: formulates the offers for flexibility services and energy production/consumption for its load areas, and then sends the offers to the market operator. The Aggregator at the time of the release of this deliverable is not yet finalized. WP3 will release an add on to D3.1 with the detailed formalization of the Aggregator role and functions.
- SP – Service Provider: is a third-party which could provide services to any of the main actors of the electricity supply chain e.g. weather forecasts, energy management services, etc.
- MGCC – Micro Grid Central Controller: centralized controller that manages the microgrid to perform the reconnection protocol.

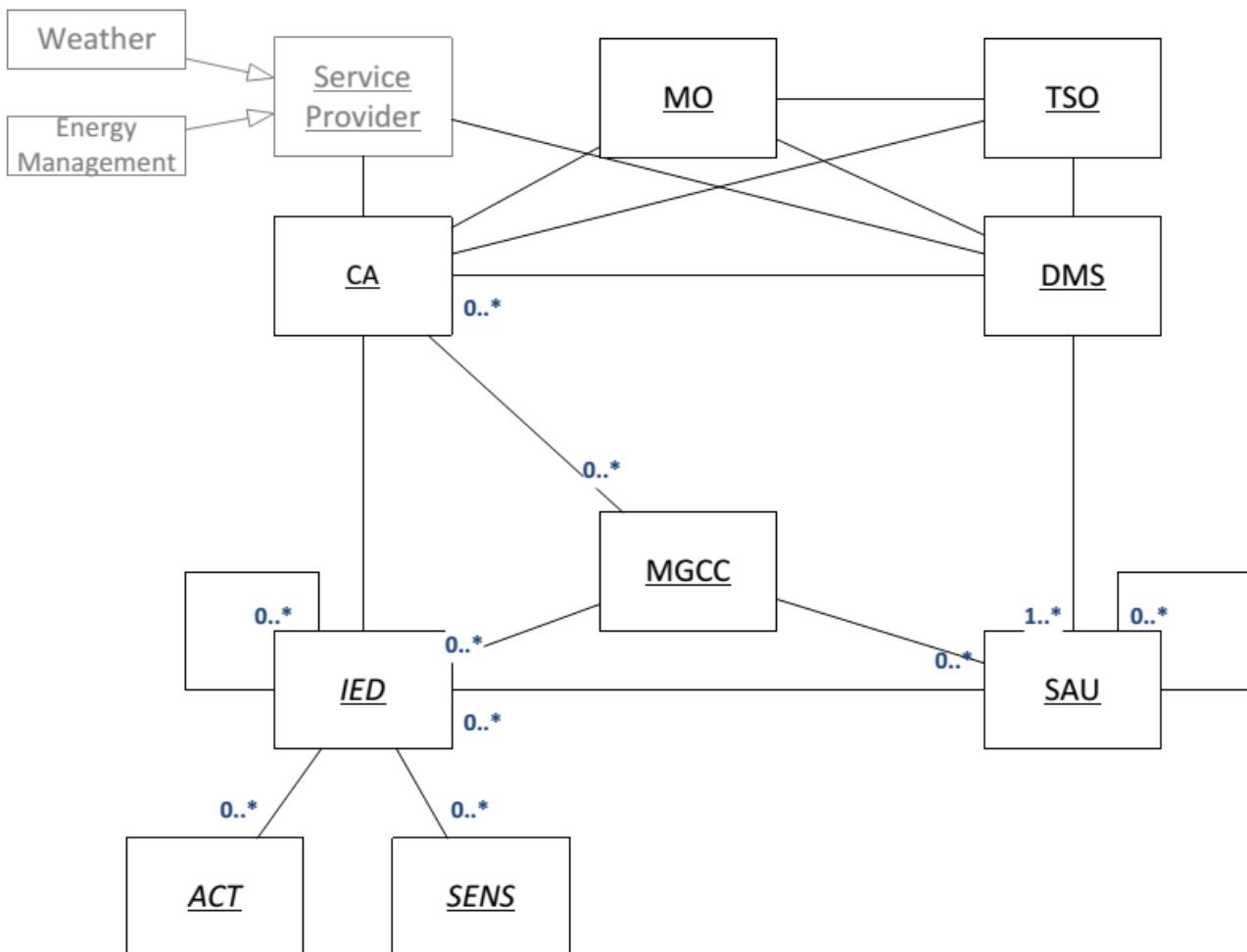


Figure 4.21: Conceptual semantic model UML diagram for the IDE4L automation architecture.

The main classes of conceptual semantic model needed in distribution automation to realize network monitoring, protection and control processes are IED, SAU and DMS. Each of them consists of several functions, interfaces and data sources. They also represent the hierarchy of automation system described in Chapter 4.4.3. DMS represents the tertiary controller, SAU the secondary controller, and IED the primary controller. DSO has a DMS in control center which is utilized to monitor and manage the whole distribution network. DMS is connected to several SAUs (e.g. located in primary substations), which may be connected to other SAUs (e.g. located in secondary substations) and IEDs located in substations or DERs. The aim is to decentralize functionalities to SAUs and IEDs traditionally located in DMS, while maintaining the overall network management in hands of DMS.

Similarly the commercial part of the semantic model consists of three classes: CA, MGCC and IED. They also represent a hierarchical system where CA realize overall monitoring and management of aggregated DERs, MGCC coordinates DERs located in specified network area, and IED represents monitoring, protection and control of DER. In order to coordinate technical (network management) and commercial actions and to provide ancillary/flexibility services, CA and MGCC are linked with distribution automation.

Both the DMS and the CA have further links with Service provider, MO and TSO to exchange information and services with them.

The decentralization of functionalities requires proper interface definitions in order to communicate between elements and to design automation architecture. Information exchange between elements is essential in order to update dynamic information and to coordinate protection and control actions. Use cases of this document will be used to identify interfaces needed in the automation architecture of active distribution network, to describe functional requirements of interfaces, and to define the non-functional requirements of communication links in order to implement use cases. Also a mapping of use cases (functionalities and information exchanges) to semantic model is needed to understand which part of the architecture may be realized by commercial products and where prototype implementations (software and hardware) is needed.

## 5. Conclusions

The automation concept and the first cut of the architecture of the active distribution grid, according to definition and requirements defined in D2.1 were presented in this D3.1.

This automation concept is going to be detailed in T3.2 to produce the architecture of the active distribution grid, according to definition and requirements defined in D2.1 and D3.1. In particular, the upcoming work consists in the formalization of the architecture into a semantic model that is universally understandable and usable.

After the study on the automation concept from state of the art projects on distribution automation, this document shows a first definition on architecture developments to be developed within IDE4L project in next stages.

This study divides the automation architecture in four areas of interest depending on the part of the network operated: Substation automation, feeder automation, DER and VPP management and LV automation. Then, a description on technologies and standards applying to this architecture is provided for development and demonstration work packages.

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## Annexes

### Annex 1 – Acronyms

- ADMS: Advanced Distribution Management System
- AEEGSI: Authority for Electrical Energy Gas and Water Service
- AEEG: Authority for Electrical Energy and Gas
- AMI: Advanced Metering Infrastructure
- AMR: Automatic Meter Reading
- ANM: Active Network Management
- DB: Data Base
- CCU: Central Control Unit
- CEI: Electro technical Committee
- CIS: Customer Information System
- CHP: Combined Heat and Power
- CO2: Carbon Dioxide
- CVPP: Commercial Virtual Power Plant
- DER: Distributed Energy Resources
- DESS: Distributed Energy Storage Systems
- DG: Distributed Generation
- DMS: Distribution Management System
- DNO: Distributed Network Operator (passive)
- DR: Demand Response
- DSO: Distribution System Operator (active)
- EEGI: European Electric Grids Initiative
- EV: Electric Vehicle
- FLISR: Fault Location, Isolation and Supply Restoration
- FRT: Fault Ride Through
- HEMS: Home Energy Management System
- HV: High Voltage
- ICT: Information and Communication Technology
- IED: Intelligent Electronic Device
- LAN: Local Area Network
- LOM: Loss-Of-Mains
- LV: Low Voltage
- LVDC: Low Voltage Direct Current
- MDMS: Meter Data Management System
- MV: Medium Voltage
- NIS: Network Information System
- OLTC: On-Load Tap Changer
- PLC: Power Line Communication
- PMU: Phase Measurement Unit
- PQ: Power Quality
- PV: Photovoltaic

- RES: Renewable Energy Sources
- RTU: Remote Terminal Unit
- SA: Smart Appliance
- SAIDI: System Average Interruption Duration Index
- SAIFI: System Average Interruption Frequency Index
- SS: Substation
- SCADA: Supervisory Control and Data Acquisition
- STATCOM: Static Switching Compensator
- SUW: Solid Urban Waste
- TSO: Transmission System Operator
- TVPP: Technical Virtual Power Plant
- VPP: Virtual Power Plant

## Annex 2 – Use Case Template Short Version

### 1 Description of the Use Case

#### Name of Use Case:

Enter a short name that refers to the activity of the Use Case itself. Example: "Determine energy balance on substation level".

#### Name Author(s) or Committee:

Person or e.g. standardization committee like Smart Grid Technical Committees or Working Group, if applicable.

#### Scope and Objectives of Function:

Describe briefly the scope, objectives, and rationale of the Use Case. The intent is to put the function in context, particularly in relationship to other related functions, such as piggybacking other functions on this function (or vice versa). This is not necessarily a justification or benefit / cost assessment, but can be used to hit the key points of the function.

#### Short description (max 3 sentences):

Short description – not more than three sentences - as service for the reader searching for a use case or looking for an overview.

#### Complete description:

A complete narrative of the function from a domain expert user's point of view, describing what occurs when, why, with what expectation, and under what conditions.

#### Actors' Names and types:

See Actor list in the Excel sheet "WG\_SusProcess\_Actors". These actors should be preferred since they are quite "standardized" for smart grids. In this case, type and the description have not to be filled in again. In case the writer of the use case defines an own actor, the actor shall be classified (type) and described.

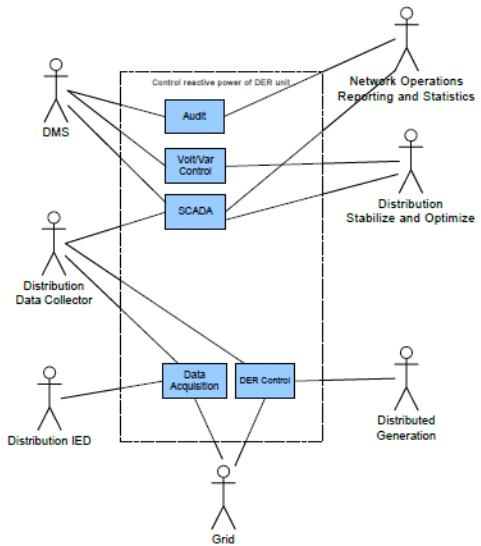
For further clarification an actor is an entity (Device, application, Person, Organization) providing inputs and/or outputs to the scenarios of the use case.

#### Functions' Names and short description:

A list of functions, with a brief description (1 sentence). The "functions" are fundamental operations that combined generate the use case (e.g. the use case "Control of reactive power of DER unit" described of the kick off meeting in Seville, was composed by Data acquisition, SCADA, Volt/VAR control, DER control and Audit functions)

## **2 Drawing or Diagram of Use Case**

*The use case diagram should contain a square. Inside the square all the functions previously listed should be included. Outside the square there must be all the actors with a line connecting them to the functions from which they are sending and /or receiving outputs.*



### 3 Mapping of actors and functions

The use case author should include the coordinates in which actors and functions must be placed.

Coordinates are defined through Zone and Domain indications (Functions and Actors can work in more than one Zone and Domain). The author can choose among the following Zones and Domains. A detailed explanation of zones and domains is given in the documents from the SGAM in the wiki.

Domains:	Zones	This coordinates will allow a first mapping of the use case into the architecture
Market	Generation	
Enterprise	Transmission	
Operation	Distribution	
Station	Der	
Field	Customer	
Process		

Annex 3 – Use Case Template General Version

## 1 Description of the Use Case

### 1.1 General

#### 1.2 Name of Use Case

ID	Domain see Annex A Selection List	Name of Use Case	Level of Depth Cluster, High Level Use Case, Detailed Use Case

#### 1.3 Version Management

Changes / Version	Date	Name Author(s) or Committee	Domain Expert	Area of Expertise / Domain / Role	Title	Approval Status draft, for comments, for voting, final
			Primary			
			Additional			
			Additional			

#### 1.4 Basic Information to Use Case

Source(s) / Literature	Link	Conditions (limitations) of Use

#### Relation to Higher Level Use Case

Cluster	Higher Level Use Case

#### Maturity of Use Case – in business operation, realized in demonstration project, , realised in R&D, in preparation, visionary

#### Prioritisation

#### Generic, Regional or National Relation

#### View - Technical / Business

#### Further Keywords for Classification

#### 1.5 Scope and Objectives of Use Case

Scope and Objectives of Function

#### 1.6 Narrative of Use Case

Narrative of Use Case
Short description – max 3 sentences
Complete description

#### 1.7 Actors: People, Systems, Applications, Databases, the Power System, and Other Stakeholders

Actor Name see Annex A Selection List	Actor Type see Annex A Selection List	Actor Description see Annex A Selection List	Further information specific to this Use Case

#### 1.8 Issues: Legal Contracts, Legal Regulations, Constraints and others

Issue - here specific ones	Impact of Issue on Use Case	Reference – law, standard, others

**1.9 Preconditions, Assumptions, Post condition, Events**

Actor/System/Information/Contract	Triggering Event	Pre-conditions	Assumption

**1.10 Referenced Standards and / or Standardization Committees (if available)**

Relevant Standardization Committees	Standards supporting the Use Case	Standard Status

**1.11 General Remarks**

General Remarks

**2 Drawing or Diagram of Use Case**

Drawing or Diagram of Use Case – recommended “context diagram” and “sequence diagram” in UML

## Annex 4 – Use Case Template Detailed Version

### 1 Description of the Use Case

#### 1.1 General

#### 1.2 Name of Use Case

ID	Domain see Annex A Selection List	Name of Use Case	Level of Depth Cluster, High Level Use Case, Detailed Use Case

#### 1.3 Version Management

Changes / Version	Date	Name Author(s) or Committee	Domain Expert	Area of Expertise / Domain / Role	Title	Approval Status draft, for comments, for voting, final
			Primary			
			Additional			
			Additional			

#### 1.4 Basic Information to Use Case

Source(s) / Literature	Link	Conditions (limitations) of Use

Relation to Higher Level Use Case	
Cluster	Higher Level Use Case

Maturity of Use Case – in business operation, realized in demonstration project, , realised in R&D, in preparation, visionary
Prioritisation
Generic, Regional or National Relation
View - Technical / Business
Further Keywords for Classification

#### 1.5 Scope and Objectives of Use Case

Scope and Objectives of Function

#### 1.6 Narrative of Use Case

Narrative of Use Case
Short description – max 3 sentences
Complete description

#### 1.7 Actors: People, Systems, Applications, Databases, the Power System, and Other Stakeholders

Actor Name see Annex A Selection List	Actor Type see Annex A Selection List	Actor Description see Annex A Selection List	Further information specific to this Use Case

#### 1.8 Issues: Legal Contracts, Legal Regulations, Constraints and others

<b>Issue - here specific ones</b>	<b>Impact of Issue on Use Case</b>	<b>Reference - law, standard, others</b>

### 1.9 Preconditions, Assumptions, Post condition, Events

<b>Actor/System/Information/Contract</b>	<b>Triggering Event</b>	<b>Pre-conditions</b>	<b>Assumption</b>

### 1.10 Referenced Standards and / or Standardization Committees (if available)

<b>Relevant Standardization Committees</b>	<b>Standards supporting the Use Case</b>	<b>Standard Status</b>

### 1.11 General Remarks

<b>General Remarks</b>

## 2 Drawing or Diagram of Use Case

<b>Drawing or Diagram of Use Case – recommended "context diagram" and "sequence diagram" in UML</b>

## 3 Step by Step Analysis of Use Case

<b>S.No</b>	<b>Primary Actor</b>	<b>Triggering Event</b>	<b>Pre-Condition</b>	<b>Post-Condition</b>

### 3.1 Steps – Normal Sequence

<b>Scenario Name :</b>						
<b>Step No.</b>	<b>Event</b>	<b>Description of Process/Activity</b>	<b>Information Producer</b>	<b>Information Receiver</b>	<b>Information Exchanged</b>	<b>Technical Requirements ID</b>
1						

### 3.2 Steps – Alternative, Error Management, and/or Maintenance/Backup Scenario

<b>Scenario Name :</b>						
<b>Step No.</b>	<b>Event</b>	<b>Description of Process/Activity</b>	<b>Information Producer</b>	<b>Information Receiver</b>	<b>Information Exchanged</b>	<b>Technical Requirements ID</b>
1						

## Annex 5 – Survey on power converters topologies and their modulation techniques able to enable the PLC communication

### Effect of power electronic converter over distribution networks with PLC communications

The aim of this section is to provide an analysis on the effect of power electronic converters in distribution networks and relate it to PLC communications. Most of the residential renewable energy sources (RES) are interfaced with the power distribution grid through power electronic converters. Power electronic converters control power flow by modulating voltage and current, to optimally suit user requirements. Typically, RES generates power in DC voltage and the power converter is in charge to inject this power to the AC distribution network. Hereafter we will refer to power electronic DC/AC converters as inverter.

DC/AC inverters have been used in industrial applications since the late 1980s. Semiconductor manufacture development resulted in many power devices such as GTO, triac, BT, IGBT and MOSFETS, suitable for power applications with switching frequencies of few kHz (GTO) to hundreds of kHz (MOSFETS). Nowadays, the vast majority of power devices for residential applications are based on IGBT or MOSFETS. Inverters have three supply methods: i) voltage source, ii) current source, and iii) impedance source. However, in RES applications, only voltage source inverters are considered. Among the voltage source DC/AC converters (VSC), it can be found different topologies:

- Single-phase half-bridge VSC
- Single-phase full-bridge VSC
- Three-phase full-bridge VSC

#### *Single-phase half-bridge VSC*

A single-phase half-bridge is shown in Figure A5.1. This topology requires two big capacitors in order to produce a neutral point N; therefore, each capacitor keeps half of the input DC voltage. Since the output voltage refers to the neutral point N, the maximum output voltage is smaller than half of the DC-link voltage if it is operating in linear modulation. Two switches S+ and S- are switched by a PWM signal, in an exclusive state with a short dead time between commutations to avoid a short circuit.

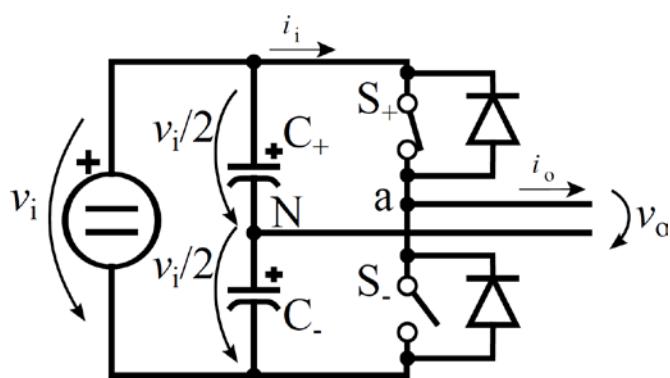


Figure A5.1: Single phase half-bridge VSC.

#### *Single-phase full-bridge VSC*

A single-phase full bridge VSC is shown in Figure A5.2. Two big capacitors may be used to generate a neutral point N, although it is not strictly necessary. Since the output voltage is no referenced to the neutral point, but is the voltage difference between branches, the effective output voltage can be greater than input DC voltage  $v_i$ . However, linear operation limits the output voltage to the DC-link voltage. The

modulation of the full-bridge is different from the half-bridge VSC described above. In this topology, a reference sinusoidal signal is applied to one branch, and the same reference signal with opposite sign is applied on the other branch.

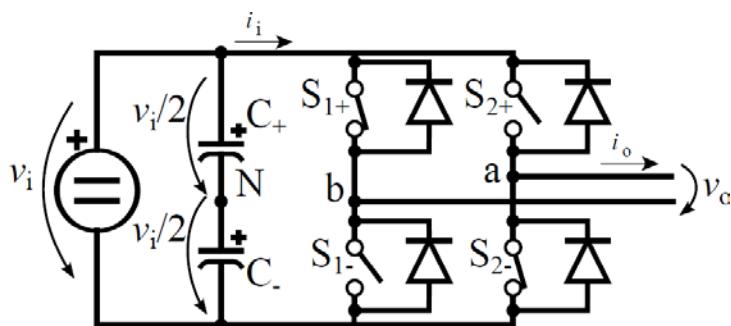


Figure A5.2: Single phase full-bridge VSC.

### Three-phase full-bridge VSC

A three-phase full-bridge converter is shown in Figure A5.3. As in the other topologies, two big capacitors may be used to generate a neutral point N, although it is not strictly necessary. In this converter, six switches S1-3+/- are capable to modulate three AC voltage waveforms  $v_{a,b,c}$ .

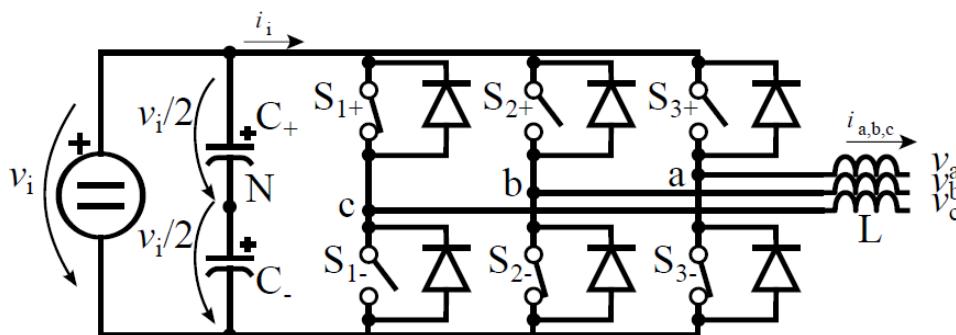


Figure A5.3: Three-phase full-bridge VSC.

The election of the VSC topology depends on the power level required by the RES installation. Typically, single-phase VSC covers the power range of hundreds of watt to several kilo-watts. Residential three-phase VSC are rated up to few tens of kilo-watts.

### Typical voltage modulation techniques

The most straightforward modulation technique is the naturally sampled PWM. This technique compares a low frequency target reference signal, typically a sinusoid, against a high-frequency carrier waveform. Typically, the carrier waveform is triangular. The crossing of both signals determines pulse generation instant and duration. However, the majority of the commercial converters are controlled using a digital modulation system, where naturally sampled PWM strategies are difficult to implement. To overcome this point, a popular alternative is to implement a regular sampled PWM strategy, where the low frequency reference waveform are sampled and held constant during each carrier interval. These sampled values are compared against the triangular carrier signal to control the switching process of each leg.

We define the amplitude modulation for a single-phase inverter as

$$m_a = \frac{v_o}{v_i/2},$$

where  $v_o$  is the fundamental component of the output voltage, and  $v_i$  is the DC voltage source. In general, modulation index  $m$  is considered smaller than unity, *i.e.* operation is in linear region. We also define the frequency modulation as

$$m_f = \frac{f_{sw}}{f_o},$$

where  $f_{sw}$  is the switching frequency and  $f_o$  is the fundamental frequency of the output voltage.

### Single-phase half-bridge VSC

Single-phase half-bridge VSC are commonly modulated with triangular regular sampled PWM. The complete harmonic solution for symmetrical regular sampled modulation of a single-phase half-bridge leg leads to express the output voltage  $v_{az}$  (respect to N) in terms of the harmonic components as

$$v_{az}(t) = \frac{4v_i}{\pi} \sum_{\substack{m=0 \\ m>0}}^{\infty} \sum_{n=1}^{\infty} \frac{1}{q} J_n \left( q \frac{\pi}{2} m_f \right) \sin \left( [q+n] \frac{\pi}{2} \right) \cos(m[\omega_{sw} t + \theta_{sw}] + n[\omega_0 t + \theta_0]),$$

Where:

$q = m + n \left( \frac{\omega_0}{\omega_c} \right)$ ,  $\omega_0 = 2\pi f_0$ ,  $\omega_{sw} = 2\pi f_{sw}$ ,  $m$  is the carrier index (the harmonic order), and  $n$  is the sideband harmonic order, and  $J_n$  is the Bessel function.

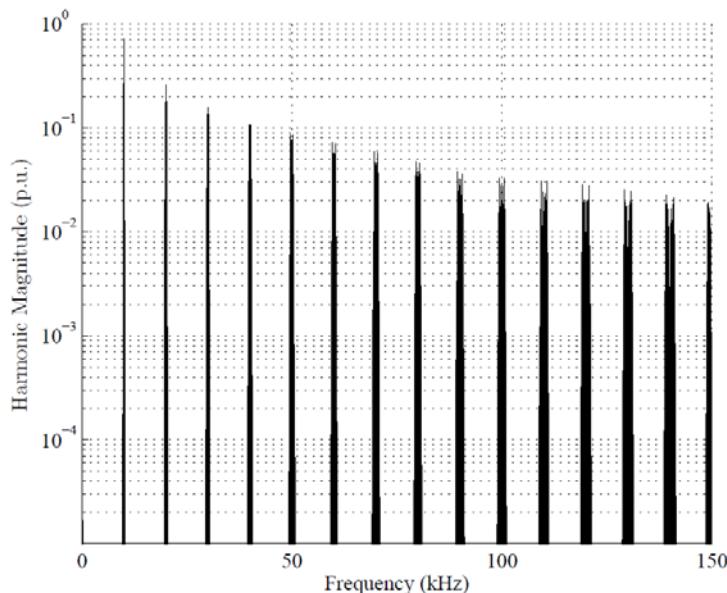


Figure A5.4: Harmonic components of a single-phase half-bridge VSC with triangular carrier waveform.

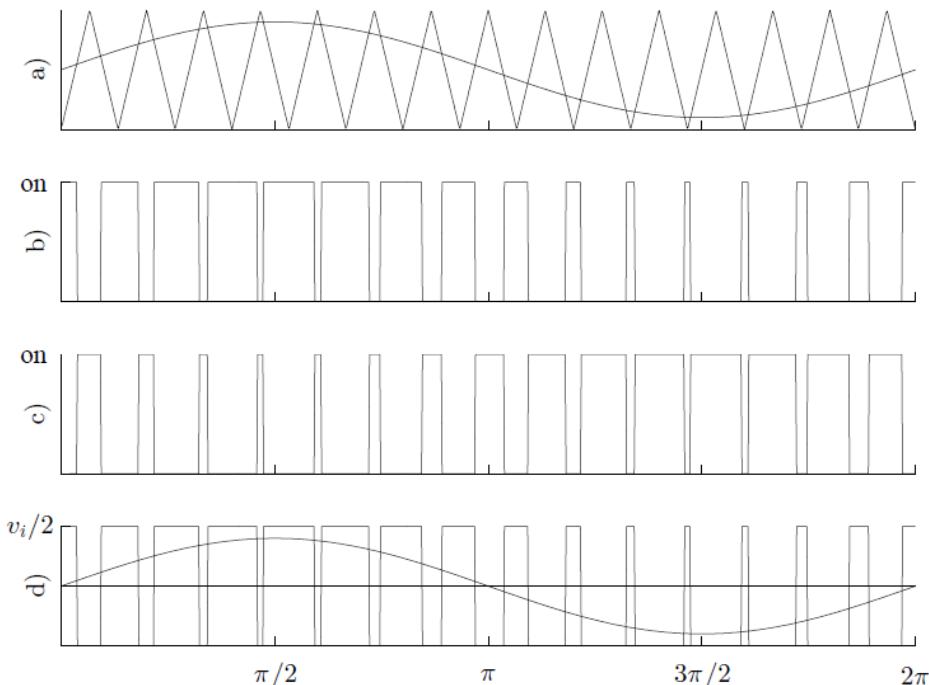


Figure A5.5: Waveforms for a single-phase half-bridge VSC.

### Single-phase full-bridge VSC

Single-phase full-bridge VSC are commonly modulated with triangular regular sampled PWM. The complete harmonic solution for symmetrical regular sampled modulation with double-edge carrier of a single-phase full-bridge VSC leads to express the output voltage  $v_{az}$  (respect to N) in terms of the harmonic components as

$$v_{ab}(t) = \frac{8v_i}{\pi} \sum_{\substack{m=0 \\ m>0}}^{\infty} \sum_{\substack{n=1 \\ n=-\infty}}^{\infty} \frac{J_n\left(q \frac{\pi}{2} m_f\right)}{q} \sin\left([q+n] \frac{\pi}{2}\right) \sin\left(n \frac{\pi}{2}\right) \cos(m[\omega_{sw} t + \theta_{sw}] + n[\omega_0 t + \theta_0]),$$

Where:

$q = m + n \left( \frac{\omega_0}{\omega_c} \right)$ ,  $\omega_0 = 2\pi f_0$ ,  $\omega_{sw} = 2\pi f_{sw}$ ,  $m$  is the carrier index (the harmonic order), and  $n$  is the sideband harmonic order, and  $J_n$  is the Bessel function.

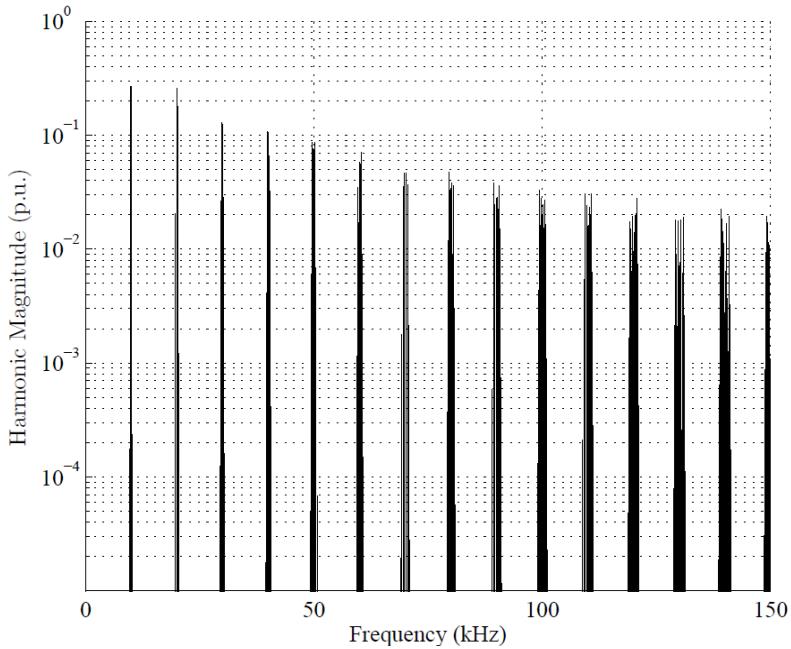


Figure A5.6: Harmonic components of leg-to-leg voltage of a single-phase full-bridge VSC with triangular carrier waveform.

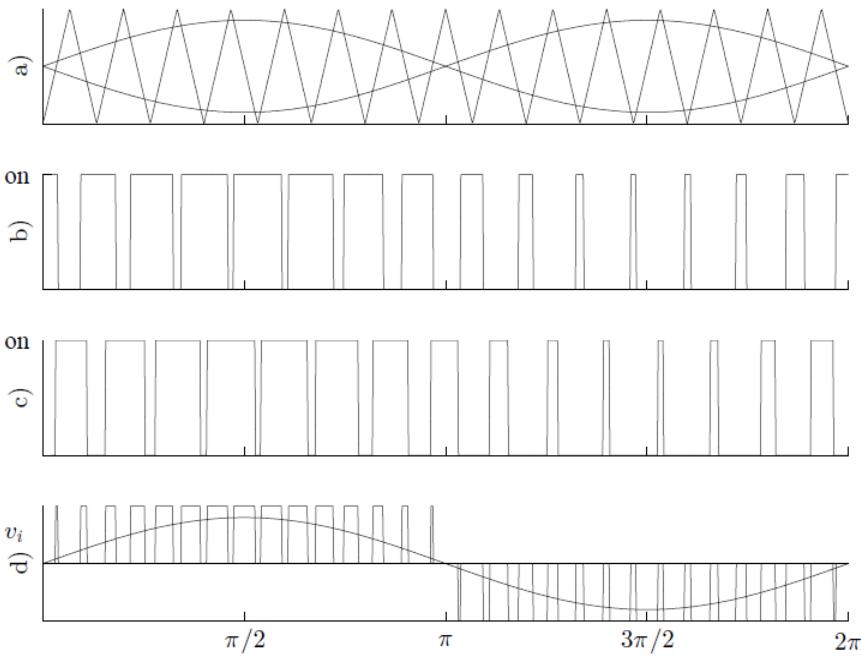


Figure A5.7: Waveforms for single-phase full-bridge VSC.

### Three-phase full-bridge VSC

Single-phase full-bridge VSC are commonly modulated with triangular regular sampled PWM. The complete harmonic solution for symmetrical regular sampled modulation with double-edge carrier of a single-phase full-bridge VSC leads to express the output voltage  $v_{az}$  (respect to N) in terms of the harmonic components as

$$v_{ab}(t) = \frac{8v_i}{\pi} \sum_{\substack{m=0 \\ m>0}}^{\infty} \sum_{\substack{n=1 \\ n=-\infty}}^{\infty} \frac{J_n\left(q \frac{\pi}{2} m_f\right)}{q} \sin\left([q+n] \frac{\pi}{2}\right) \sin\left(n \frac{\pi}{2}\right) \cos(m[\omega_{sw} t + \theta_{sw}] + n[\omega_0 t + \theta_0]),$$

Where:

$q = m + n \left( \frac{\omega_0}{\omega_c} \right)$ ,  $\omega_0 = 2\pi f_0$ ,  $\omega_{sw} = 2\pi f_{sw}$ ,  $m$  is the carrier index (the harmonic order), and  $n$  is the sideband harmonic order, and  $J_n$  is the Bessel function.

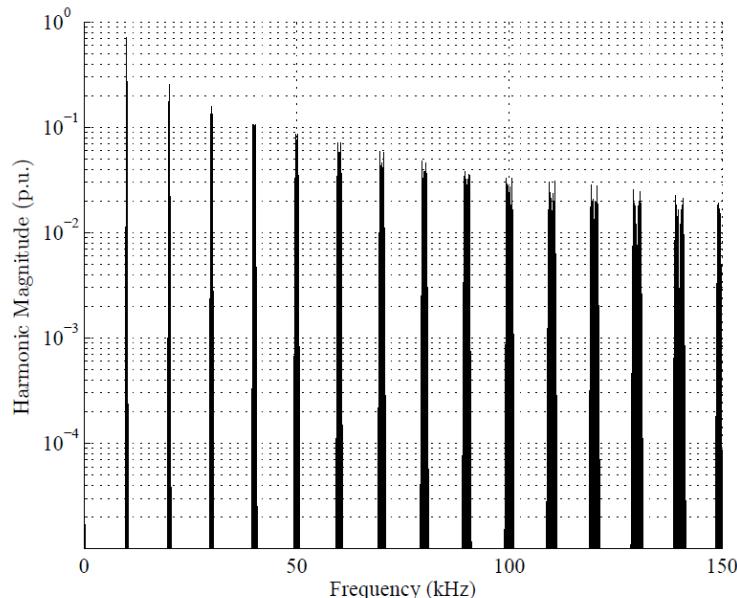


Figure A5.8: Harmonic components of leg-to-leg voltage of a three-phase full-bridge VSC with triangular carrier waveform.

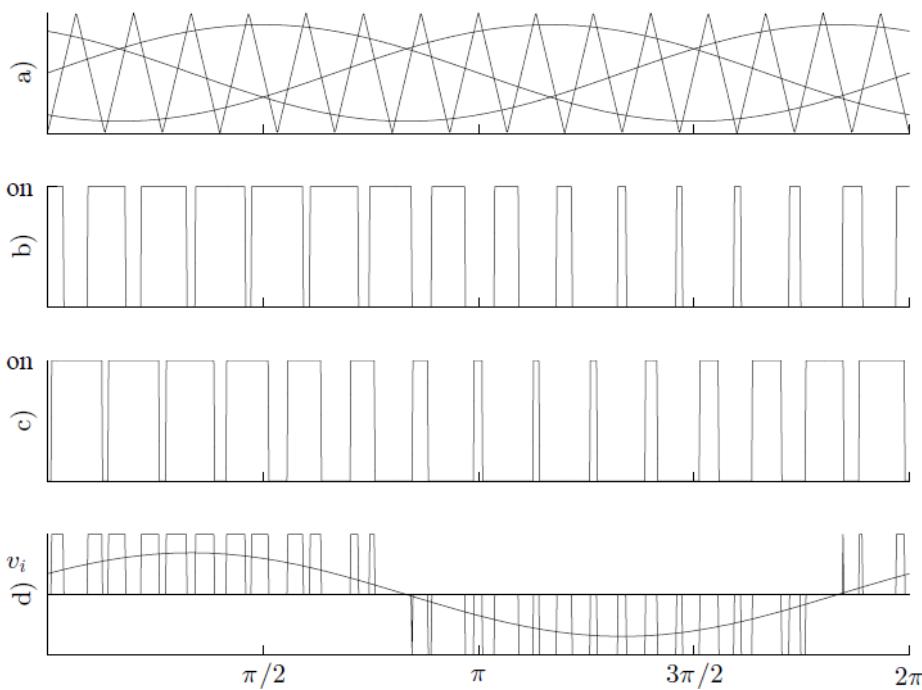


Figure A5.9: Waveforms for three-phase full-bridge VSC.

### Typical output current filters

In residential renewable energy applications, voltage source converters (VSC) are typically interfaced with a single low-frequency inductor with the distribution grid. This output filter is designed to reduce the voltage components at the switching frequency. The output impedance of the power inverter is thus dominated by the output filter.

Although all inductors consist of a coil of wire, many variations on the actual method of device construction exist. The core of low-frequency inductors are often made of stacks of thin steel sheets or laminations oriented parallel to the field, with an insulating coating on the surface, preventing eddy currents between the sheets with the aim of reducing the energy losses.

In order to characterize the output filter behavior, it will be compared the equivalent inductor circuit and the experimental measurement of a real power electronic converter output filter. The resistance of the inductor's coils is considered a parasitic component of the inductor impedance and designated as  $R_{parasitic}$ . The proximity of the adjacent inductor coils introduces a parasitic capacitance component into the inductor equivalent impedance. This parasitic capacitance, designated as  $C_{parasitic}$ , increases significantly when space saving winding techniques (such as multiple layers of coils) are employed. The equivalent model can be expressed as a series combination of the element inductance and the parasitic resistance

$$Z_s = j\omega L + R_{parasitic}$$

in parallel with the parasitic capacitance of the inductor

$$Z_p = \frac{1}{j\omega C_{parasitic}},$$

resulting in

$$Z_{VSC} = \frac{j\omega L + R_{para.}}{1 + j\omega^2 LC_{para.} + j\omega R_{para.} C_{para.}}$$

In Figure A5.10 it can be seen the comparison between a real 4.6 mH inductor and the previous model with the proper parameter values. In the same figure it can also be seen the impedance for different inductance values.

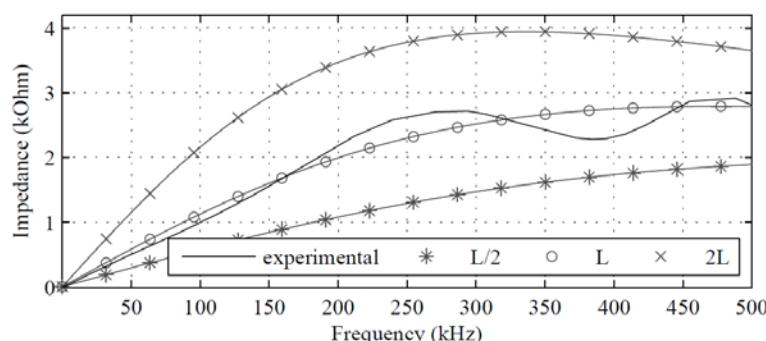


Figure A5.10: Comparison of a real  $L=4.6$  mH VSC output filter and the theoretical model.

## Annex 6 – IDE4L Primary Use Cases

### MV Real-Time Monitoring

The use case covers the process of collecting data into a unique repository called Primary Substation Data eXchange Platform (PSDXP), located in the primary substation and includes measurements (mean values and PQ indexes), states and alarms from the MV grid. This information is needed for algorithms (State Estimation, State Forecasting, and Optimal Power Flow) intended to be developed and control actions to perform correctly. The monitoring system should be able to acquire the main electrical data, such as mean values of V, I, Q, P, transformers' status, PQ indexes, status of breakers/disconnectors, voltage or reactive power set-points for generation connected on the MV network, and alarms related to events and faults (IED-PQM-RTU). These quantities are made available from a large number of devices: Remote Terminal Units (RTUs), Power Quality Meters (PQMs) and Phasor measurement Units (PMUs).

All these devices have been clustered in the actor Intelligent Electronic Device (IED). With IEDs actors and sensors interfaces are intended, which are placed in primary and secondary substation as well as distributed in the grid. LV data can also be acquired from the Secondary Substation Data eXchange Platform (SSDXP).

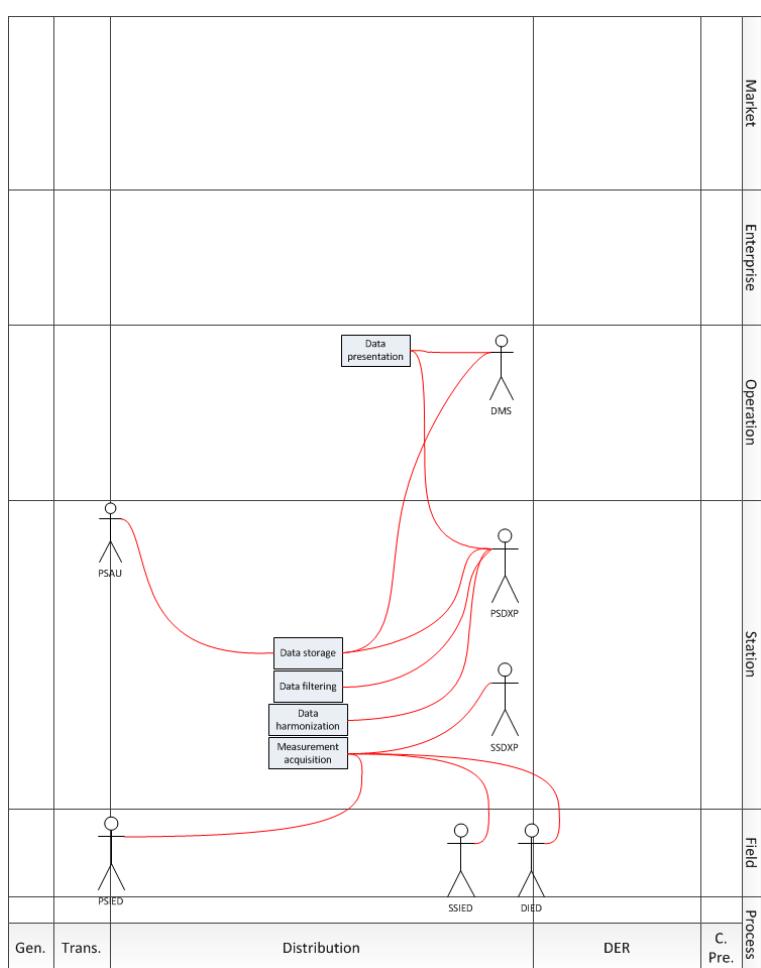
The steps for MV Real Time Monitoring are as follows:

1. Data are collected in an asynchronous fashion from IEDs. The collection of measurements is implemented in the Measurement Acquisition (MA) function, in order to accept different protocols – in particular the IEC61850 protocols (MMS, GOOSE, SV) for substation IEDs and the C37.118.1-2011 for PMUs.
2. Acquired measurements are stored in the Primary substation Data Exchange platform (PSDXP), through the data storage (DS) function. DS function is intended to represent both the process of storage and extraction of data from the database. The PSDXP should contain an Interface layer in order to accept data from different protocols and a Data layer, with a database, where the data are written into.
3. Corrupted measurements (bad data) need to be detected and processed with filtering methods. These methods are in some dedicated functions that have been clustered under the name Data filtering (DF) and harmonization (DH). Data are stored and ordered with respect to time.
4. In this level of the architecture the stored data will be available for the control entities PSAU (Primary Substation Automation Unit), as well as to higher levels such as the Distribution Management System (DMS) that is located in the control center. The Data Presentation (DP) function regards the mathematical computation conducted in order to make the available data suitable for visual representation to operators.

**Table A6.1: Actors and functions for MV Real-Time Monitoring use case.**

Actors	Functions
Primary Substation Automation Unit (PSAU)	Data Storage (DS)
Distribution Management System (DMS)	Data Filtering (DF)

Distributed Intelligent Electronic Devices (DIED)	Data Harmonization (DH)
Secondary Substation Intelligent Electronic Devices (SSIED)	Measurement Acquisition (MA)
Primary Substation Data eXchange Platform (PSDXP)	Data Presentation (DP)
Secondary Substation Data eXchange Platform (SSDXP)	



**Figure A6.1: Smart Grid Plane diagram of IDE4L – MV Real-Time Monitoring UC.**

## LV Real-Time Monitoring

The use case consists of data collection into a unique repository called Secondary Substation Data eXchange Platform (SSDXP), located in Secondary Substation and includes measurement (mean values and PQ indexes), states and alarms from the LV grid. This information is needed for the algorithms (State Estimation, State Forecasting, and Optimal Power Flow) and control actions to perform correctly. The

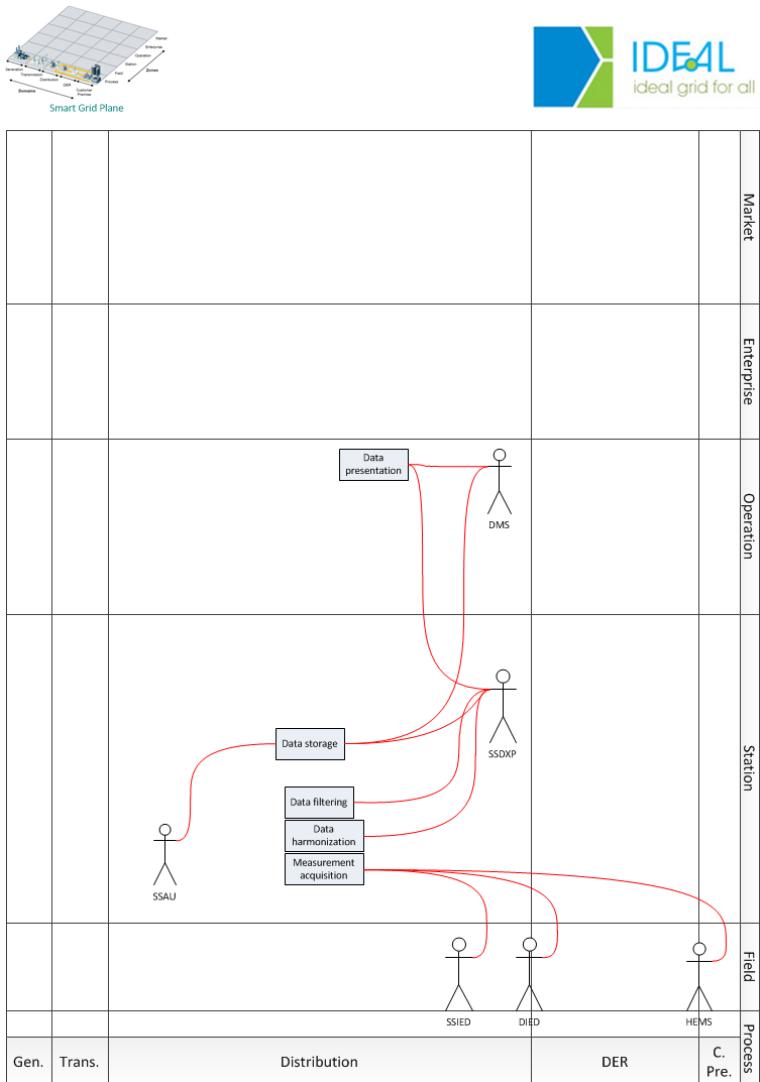
monitoring system should be able to acquire main electrical data, such as mean values of V, I, Q, P, transformers' status, Load profiles from LV customers and generations (SM/MDC), PQ indexes, status of breakers/disconnectors, voltage or reactive power set-points for generation connected on the LV network, and alarms related to events and faults (IED-PQM-RTU). The steps for LV Real Time Monitoring are as follow:

1. Data are collected in an asynchronous fashion from Distributed Intelligent Electronic Devices (DIED), Secondary Substation Intelligent Electronic Devices (SSIED) and Home Energy Management System (HEMS). The Distributed Intelligent Electronic Devices (DIED) and Secondary Substation Intelligent Electronic Devices (SSIED) are intended to represent the set of measurement units and data concentrators that are available in the distribution grid and in the secondary substation, respectively. In particular the measurement devices to be considered are Electronic Meters (EM) on the connection point of LV customers/productions. Data of EMs are often collected by a Meter Data Concentrator (MDC) system, installed in the secondary substation. Furthermore, Remote Terminal Units (RTUs), Power Quality Meters (PQMs), and Phasor Measurement Units (PMUs) are also taken into account, even though their application in distribution system is currently under discussion, and named after IEDs. Home energy management system (HEMS) can also provide measurements, but has been considered as a different actor as it represents the interface between the prosumer and the Commercial Aggregator (CA). The collection of measurements is implemented in the Measurement Acquisition (MA) function, in order to accept different protocols – in particular the protocols defined in IEC 61850 standard (MMS, GOOSE, SV) for substation IEDs, the DLMS/COSEM protocol for the communication with electronic meters (EM) and the C37.118.1-2011 for PMUs.
2. Acquired measurements are stored in the Secondary Substation Data eXchange Platform (SSDXP), through the Data Storage (DS) function. The DS function is intended to represent both the process of storage and extraction of data from the database. The SSDXP should contain an Interface layer in order to accept data from different protocols and a data layer with a database where the data are written into.
3. Corrupted measurements (Bad data) need to be detected and processed with filtering methods. These methods are in dedicated functions, which have been clustered under the name Data Filtering (DF).
4. In this level of the architecture the stored data will be available for the control entities PSAU (Primary Substation Automation Unit) and SSAU (Secondary Substation Automation Unit) to perform local computation, as well as to higher levels such as the Distribution Management System (DMS) that is located in the control center. The Data Presentation (DP) function regards the mathematical computation executed in order to make the available data suitable for visual representation to operators.

**Table A6.2: Actors and functions for LV Real-Time Monitoring use case.**

Actors	Functions
Secondary Substation Automation Unit (SSAU)	Data Storage (DS)
Distribution Management System (DMS)	Data Filtering (DF)
Distributed Intelligent	Data Harmonization (DH)

Electronic Devices (DIED)	
Secondary Substation Intelligent Electronic Devices (SSIED)	Measurement Acquisition (MA)
Primary Substation Data eXchange Platform (PSDXP)	Data Presentation (DP)
Secondary Substation Data eXchange Platform (SSDXP)	
Home Energy Management System (HEMS)	



**Figure A6.2: Smart Grid Plane diagram of IDE4L – LV Real-Time Monitoring UC.**

## Real-Time MV State Estimation

The objective of the real-time MV state estimation (MVSE) is to obtain the best possible estimation for the MV network state. The state estimator combines all the available measurement information and calculates the most likely state of the network. State estimations are calculated for present time ( $t=0$ ) using the newest available input data.

The steps in the Real-Time MV State Estimation are as follows:

1. State estimation is performed by PSAU. The input data, namely the real-time measurements for the loads, voltages, currents and power flows from available measurement devices and load models for unmeasured buses, are retrieved by these actors from the Primary Substation Data eXchange Platform (PSDXP), through the DS function. Furthermore the topology should be given once, and then possibly updated when a reconfiguration occurs.
2. These available measurements are passed through a filter, represented with the DF function, for data verification and to process the erroneous measurements. Load models are used as pseudo-measurements for unmeasured customer nodes.
3. State estimation is calculated with a function called Estimate State (ES).
4. Eventually the results from the MSVE are stored in the Primary Substation Data eXchange Platform (PSDXP) with the Data Storage (DS) function. The states are then available for other functions that request the real-time state estimates on the low and medium voltage network.

**Table A6.3: Actors and functions for Real-Time MV State Estimation use case.**

Actors	Functions
Primary Substation Automation Unit (PSAU)	Estimate State (ES)
Primary Substation Data eXchange Platform (PSDXP)	Data Storage (DS)
	Data Filtering (DF)

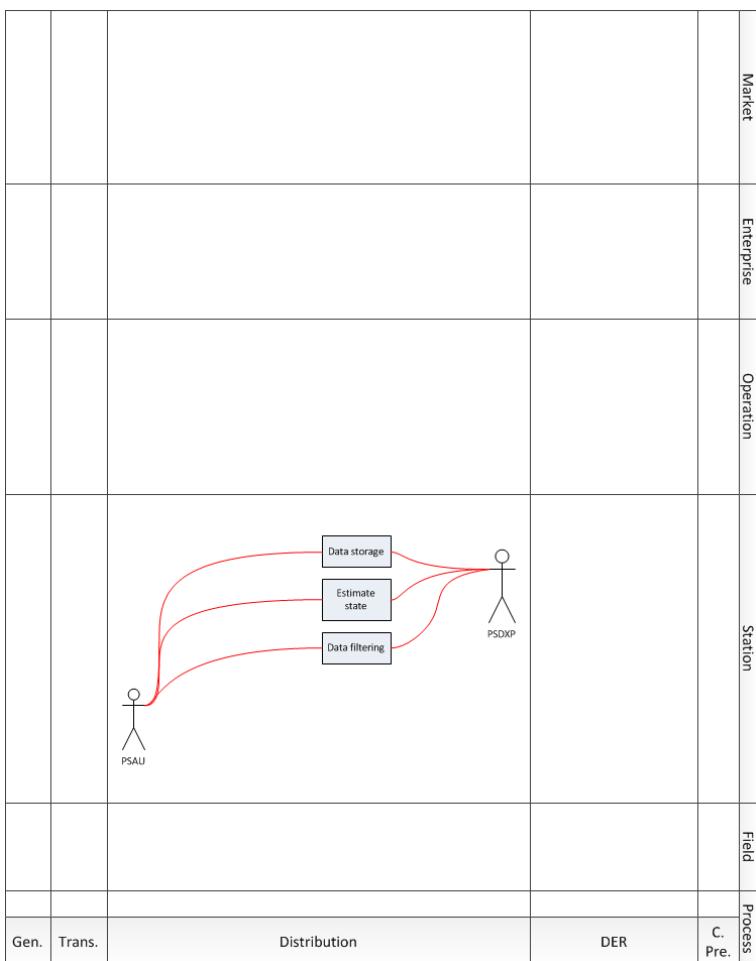
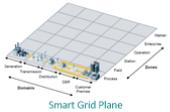


Figure A6.3: Smart Grid Plane diagram of IDE4L – Real-Time MV State Estimation UC.

## Real-Time LV State Estimation

The objective of the real-time LV state estimation (LVSE) is to obtain the best possible estimation for the LV network state. The state estimator combines all the available measurement information and calculates the most likely state of the network. State estimations are calculated for present time ( $t=0$ ) using the newest available input data.

The steps in the Real-Time LV State Estimation are as follows:

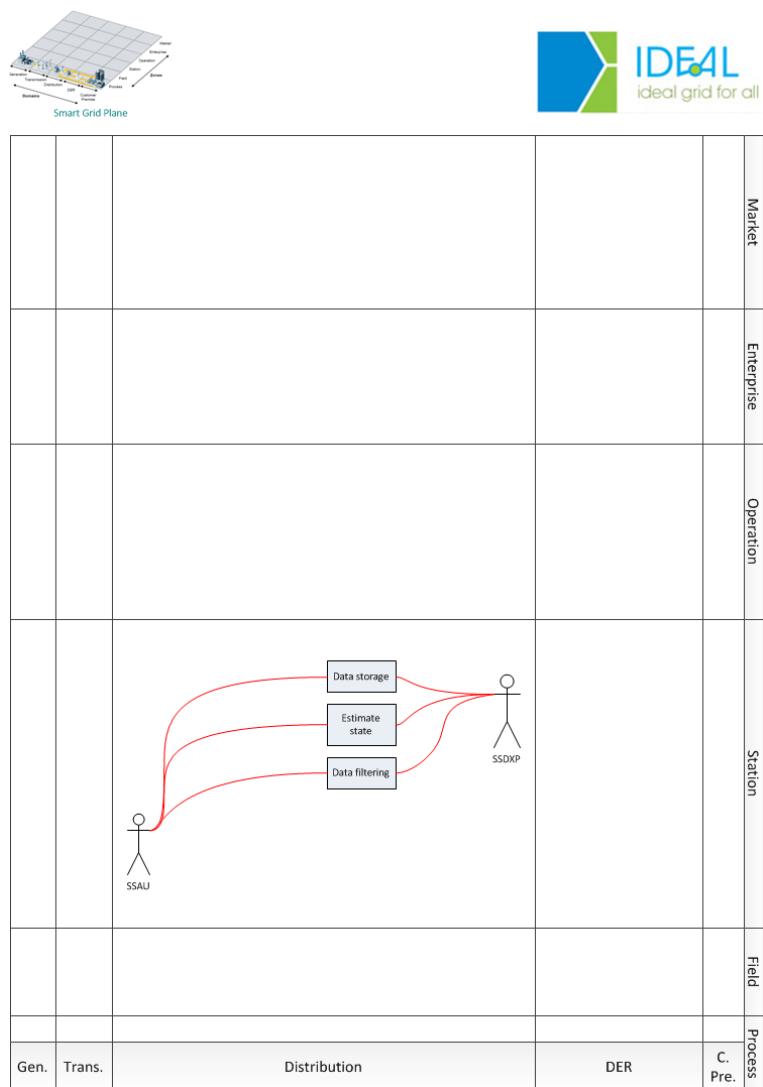
1. State estimation is performed by SSAU. The input data, namely the real-time measurements for the loads, voltages, currents and power flows from available measurement devices and load models for unmeasured buses, are retrieved by these actors from the Secondary Substation Data eXchange Platform (SSDXP), through the DS function. Furthermore the topology should be given once, and then possibly updated when a reconfiguration occurs.
  2. These available measurements are passed through a filter, represented with the DF function, for data verification and to process the erroneous measurements. Load models are used as pseudo-measurements for unmeasured customer nodes.

3. State estimation is calculated/executed with a function called Estimate States (ES).

4. Eventually the results are stored in the Secondary Substation Data eXchange Platform (SSDXP) with the DS function. The states are then available for other functions that request the real-time state estimates on the low and medium voltage network.

**Table A6.4: Actors and functions for Real-Time LV State Estimation use case.**

Actors	Functions
Secondary Substation Automation Unit (SSAU)	Estimate State (ES)
Secondary Substation Data eXchange Platform (SSDXP)	Data Storage (DS)
	Data Filtering (DF)



**Figure A6.4: Smart Grid Plane diagram of IDE4L – Real-Time LV State Estimation UC.**

## MV Load and State Forecast

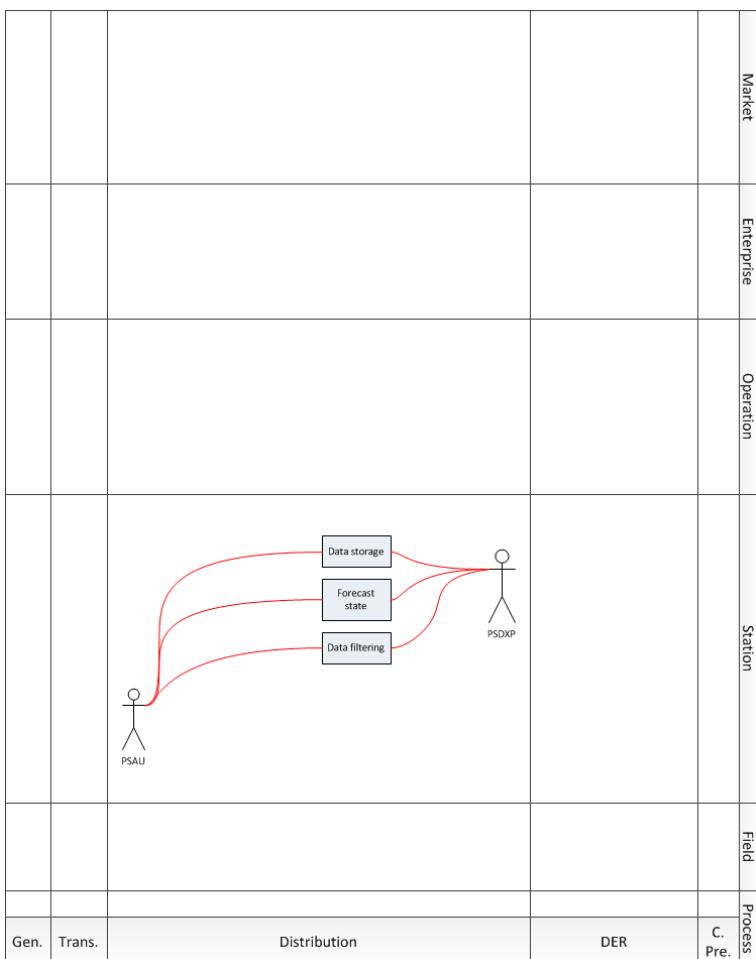
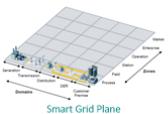
The objective of the Medium Voltage Forecast (MVF) is to obtain adequate distributional forecasts for the load and production, as well for the voltage status, in MV networks. The available data series (e.g. historical load and generation profiles, weather forecasts and scheduled events) are applied to produce the distributional forecasts for the aggregated load and production in the network – K time steps ahead – and then computed in a state estimator in order to obtain the forecasted state. The forecast will run on operator's request (on-demand or scheduled) and deliver distributional properties for the pre-requested prediction horizon.

The steps in the MV Load and State Forecast are as follows:

1. Forecast runs on fixed interval or under DMS request. The MV feeder time series (measurements) up to time t are retrieved from the Primary Substation Data eXchange Platform (PSDXP) with the DS function. Aggregated load models (e.g. previously forecasted values) are used as pseudo-measurements for unobserved states in the network. Also external variables/forecasts are retrieved from the PSDXP and adopted by the forecaster (e.g. meteorological variables/forecasts and scheduled calendar events).
2. Data are passed through a filter for data verification with the DF function.
3. The forecaster (FC) generates the forecasts for the load/production in the network nodes – K time steps ahead – and subsequently for the networks states, namely voltage magnitude and phase angle, with the forecast States (FS) function.
4. Results are stored in the Primary Substation Data eXchange Platform (PSDXP) through the DS function.

**Table A6.5: Actors and functions for MV Load and State Forecast use case.**

Actors	Functions
Primary Substation Automation Unit (PSAU)	Forecast State (FS)
Primary Substation Data eXchange Platform (PSDXP)	Data Storage (DS)
Distribution Management System (DMS)	Data Filtering (DF)



**Figure A6.5: Smart Grid Plane diagram of IDE4L – MV Load and State Forecast UC.**

### LV Load and State Forecast

The objective of the Low Voltage Forecast (LVF) is to obtain adequate distributional forecasts for the load and production, as well for the voltage status, in LV networks. The available data series (e.g. historical load and generation profiles, weather forecasts and scheduled events) are applied to produce the distributional forecasts for the aggregated load and production in the network – K time steps ahead – and then computed in a state estimator in order to obtain the forecasted state. The forecast will run on operator's request (on-demand or scheduled) and deliver distributional properties for the pre-requested prediction horizon.

The steps in the LV Load and State Forecast are as follows:

1. Forecast runs on fixed interval or by DMS request. The feeder time series (measurements) up to time t are retrieved from the Secondary Substation Data eXchange Platform (SSDXP) with the DS function. Load models (e.g. previously forecasted values) are used as pseudo-measurements for unobserved states in the network. Also external variables/forecasts are retrieved from the SSDXP and adopted by the forecaster (e.g. meteorological variables/forecasts and scheduled calendar events).
2. Data are passed through a filter for data verification with the DF function.

3. The forecaster (FC) generates the forecasts for the load/production in the network nodes – K time steps ahead – and subsequently for the networks states, namely voltage magnitude and phase angle, with the forecast states (FS) function.

4. Results are stored in the Secondary Substation Data eXchange Platform (SSDXP) through the DS function.

**Table A6.6: Actors and functions for LV Load and State Forecast use case.**

Actors	Functions
Secondary Substation Automation Unit (SSAU)	Forecast State (FS)
Secondary Substation Data eXchange Platform (SSDXP)	Data Storage (DS)
Distribution Management System (DMS)	Data Filtering (DF)

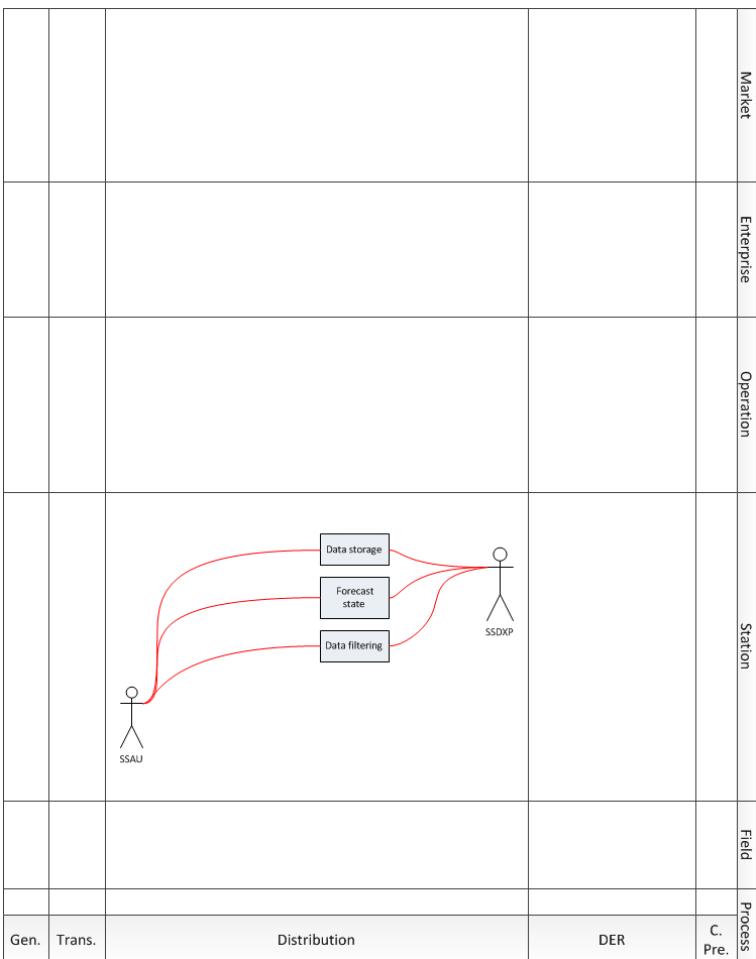
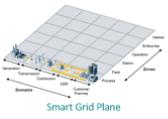


Figure A6.6: Smart Grid Plane diagram of IDE4L – LV Load and State Forecast UC.

### Dynamic Monitoring for TSO

This primary use case is composed by two PUCs as defined within the project, namely the “grid dynamic monitoring for providing “dynamic” information to TSOs” and “communication devices for transmitting signals considering long distances within the electrical distribution system”. These use cases aim at utilizing time-stamped PMU data and discrete unsynchronized traditional measurements, for providing “dynamic” information on distribution grid operation to TSOs. The monitoring algorithms receive inputs at primary substation level of selected and homogenized time-stamped PMU data and discrete unsynchronized traditional measurements and outputs “dynamics” to TSOs. PMU and RTU here are considered as generic IEDs. The main steps of the UCs are:

1. Transmitting PMU and traditional measurements via standard protocols such as IEC 61850 MMSs and C37.118 to data concentrators situated in substation. PMU are here called as Primary Substation Intelligent Electronic Devices (PSIED) and Secondary Substation Intelligent Electronic Devices (SSIED), whereas the Phasor Data Concentrator (PDC) is simply the Primary Substation Data eXchange Platform (PSDXP) and Secondary Substation Data eXchange Platform (SSDXP). This function is part of the cluster Measurement acquisition (MA).

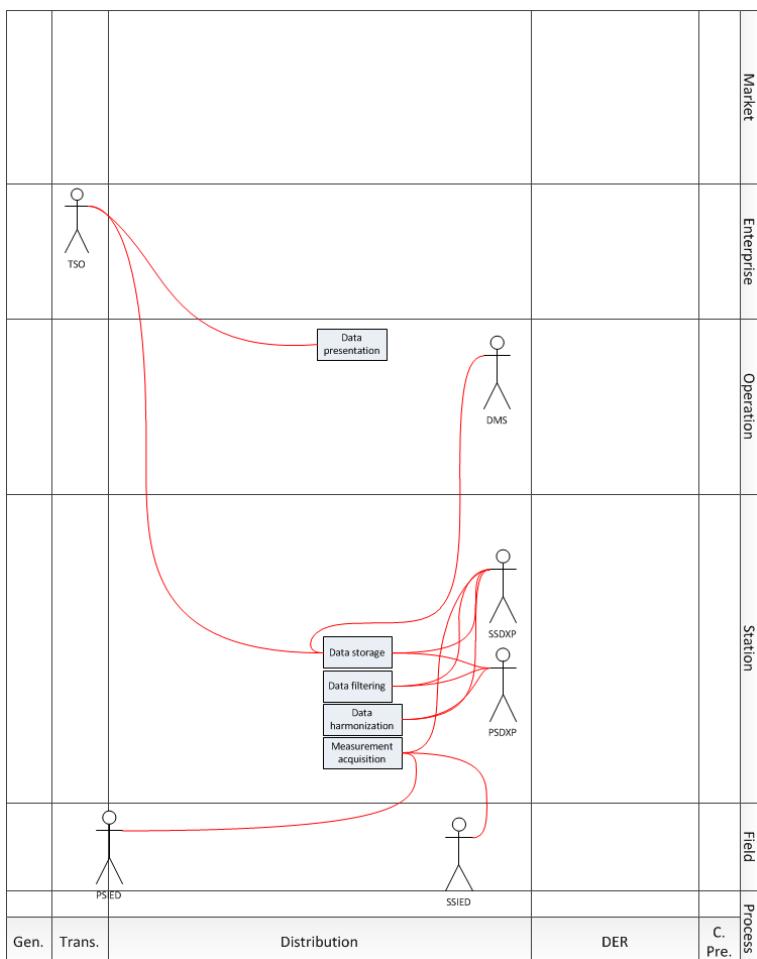
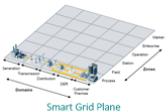
3. Data are received and stored in Primary Substation Data eXchange Platform (PSDXP) and Secondary Substation Data eXchange Platform (SSDXP), through the function Data Storage (DS).

2. Some computation is performed in order to handle Bad data and harmonizing PMU and traditional measurements. Furthermore low-frequency oscillations, sub-synchronous oscillations, voltage stability indices are derived out of the harmonized data. These set of calculation goes under function Data filtering (DF) and Data Harmonization (DH).

4. The aforementioned information is sent to TSO through the DS function on regular bases or under demand of the DMS. Data can be then visualized through Data presentation function (DP).

**Table A6.7: Actors and functions for Dynamic Monitoring for TSO use case.**

Actors	Functions
Transmission System Operator (TSO)	Measurement Acquisition (MA)
Secondary Substation Intelligent Electronic Devices (SSIED)	Data Storage (DS)
Primary Substation Intelligent Electronic Devices (PSIED)	Data Filtering (DF)
Distribution Management System (DMS)	Data Harmonization (DH)
Secondary Substation Data eXchange Platform (SSDXP)	Data Presentation (DP)
Primary Substation Data eXchange Platform (PSDXP)	



**Figure A6.7: Smart Grid Plane diagram of IDE4L – Dynamic Monitoring for TSO UC.**

### Network Description Update

The use case consists in updating the network description (topology, assets, and customers) of the DXPs, located in substations. This update process maintains aligned: the description of the network topology, the list of assets and their parameters, the list of customers and some relevant information and allow performing correctly state estimation, forecasting and controlling algorithms. This use case will trigger an update of the network description when a new part of the grid or a new customer/generator is changed or added. The DMS needs a subset of the whole information, in order to locally execute algorithms such as the State Estimation or the Optimal Power Flow. The same data are needed in primary and secondary substation – within the DXP – to allow a local execution of those algorithms. The steps in the Network description update UC are as follows:

1. A customer change or a grid change happens in the grid. The PSIEDs, SSIEDs, the Network information service (NIS), Geographic information system (GIS) and Asset management system, the customer information acquisition and the HEMS, are able to detect some change and trigger this use case.

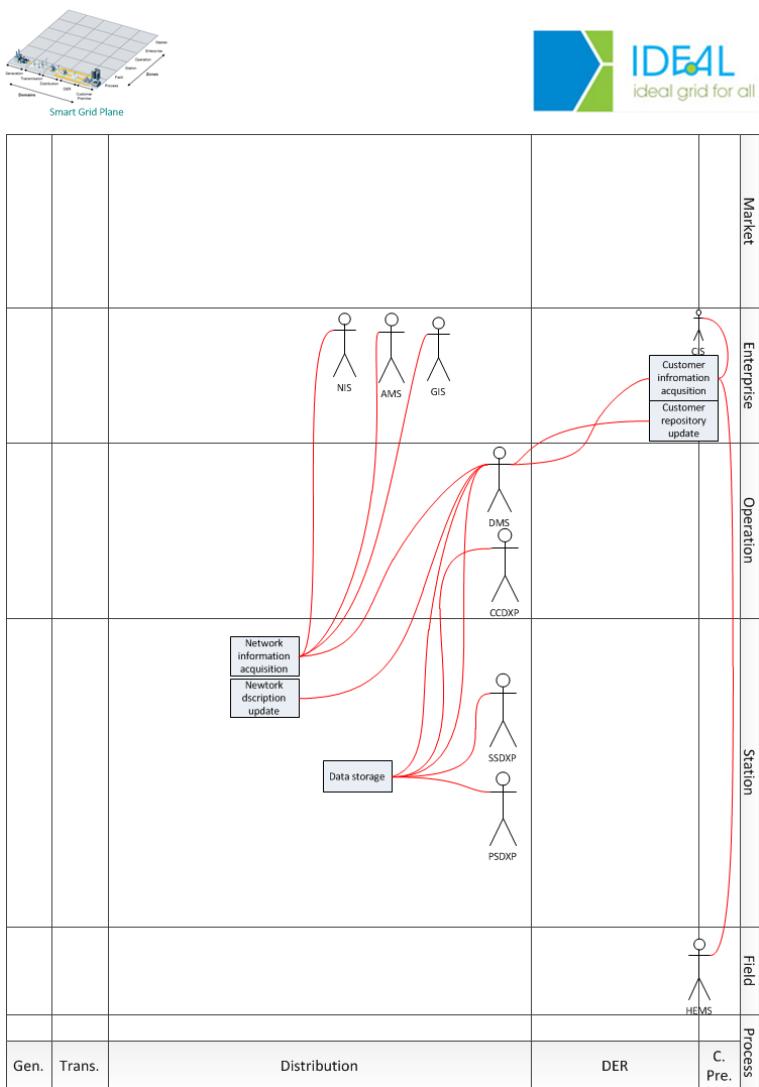
2. The DMS is informed regarding the last changes on the network by the function Network information acquisition (NIA), and regarding the customers' changes by the function customer information acquisition (CIA).
3. The functions Network information acquisition (NIA) and customer information acquisition (CIA) are performed by the DMS in order to retrieve the updated information about a certain portion of the network. The functions NIA and CIA represent both the notice of updating for the DMS about the changes in the grid and the customers, and the extraction of network and customer information. The updated grid changes are provided by the actors Network information service (NIS), Geographic information system (GIS) and Asset management system (AMS), Secondary Substation Intelligent Electronic Devices (SSIED) and Primary Substation Intelligent Electronic Devices (PSIED). The updated list of customer contracts is provided by the Customer information system (CIS) and the Home energy management systems (HEMSs).
4. The DMS updates the information of the grid with the network description update (NDU) function.

5. The DMS updates the information of the customers with the customer repository update (CRU) function.
6. The updated information of the network and the customers are stored in the Secondary Substation Data eXchange Platform (SSDXP), Primary Substation Data eXchange Platform (PSDXP), Control Center Data eXchange Platform (CCDXP) with the function Data Storage (DS).

**Table A6.8: Actors and functions for Network Description Update use case.**

Actors	Functions
Control Center Data eXchange Platform (CCDXP)	Network Information Acquisition (NIA)
Primary Substation Data eXchange Platform (PSDXP)	Customer Information Acquisition (CIA)
Secondary Substation Data eXchange Platform (SSDXP)	Network Description Update (NDU)
Distribution Management System (DMS)	Customer Repository Update (CRU)
Geographic Information System (GIS)	Data Storage (DS)
Asset Management System (AMS)	
Customer Information Service (CIS)	
Network Information Service (NIS)	

Home Energy Management System (HEMS)	
Secondary Substation Intelligent Electronic Devices (SSIED)	
Primary Substation Intelligent Electronic Devices (PSIED)	



**Figure A6.8: Smart Grid Plane diagram of IDE4L – Network Description Update UC.**

### Protection Configuration Update

The use case consists of updating the configuration file of protection devices, in terms of status of breakers and disconnectors but also changing in settings such as maximum current threshold, voltage/frequency bands, trip delays and changing in the logic selectivity rules (publish/subscribe relations) when a change is done in the network configuration. The update is performed by the PSAU and SSAU and communicated to the IEDs. The use case must leverage on standard protocols to limit efforts in integration and to provide an

easily-exploitable solution, such as the: IEC61850 Substation Configuration Language (SCL) for the description of the automation system and the IEC61850-MMS for the updated of the configuration files/values. The steps in the Network description update UC are as follows:

1. The update process starts when a change is detected in the network configuration (status of breakers and disconnectors). The update may be triggered by the information obtained in the MVRT and LVRT monitoring UCs stored in the Primary Substation Data eXchange Platform (PSDXP) and Secondary Substation Data eXchange Platform (SSDXP), and extracted through the function data storage (DS).
2. PSAUs and SSAUs update the parameters of the protection devices and communicate both to the Primary Substation Data eXchange Platform (PSDXP) and Secondary Substation Data eXchange Platform (SSDXP) and the Primary Substation Intelligent Electronic Devices (PSIED), Secondary Substation Intelligent Electronic Devices (SSIED) and Distributed Intelligent Electronic Devices (DIED) by means of the protection configuration update (PCU) function.
3. The new states of the protection devices are stored in the DXPs by means of the data storage (DS) function

**Table A6.9: Actors and functions for Protection Configuration Update use case.**

Actors	Functions
Primary Substation Data eXchange Platform (PSDXP)	Protection Configuration Update (PCU)
Secondary Substation Data eXchange Platform (SSDXP)	Data Storage (DS)
Primary Substation Automation Unit (PSAU)	
Secondary Substation Automation Unit (SSAU)	
Primary Substation Intelligent Electronic Devices (PSIED)	
Secondary Substation Intelligent Electronic Devices (SSIED)	
Distributed Intelligent Electronic Devices (DIED)	

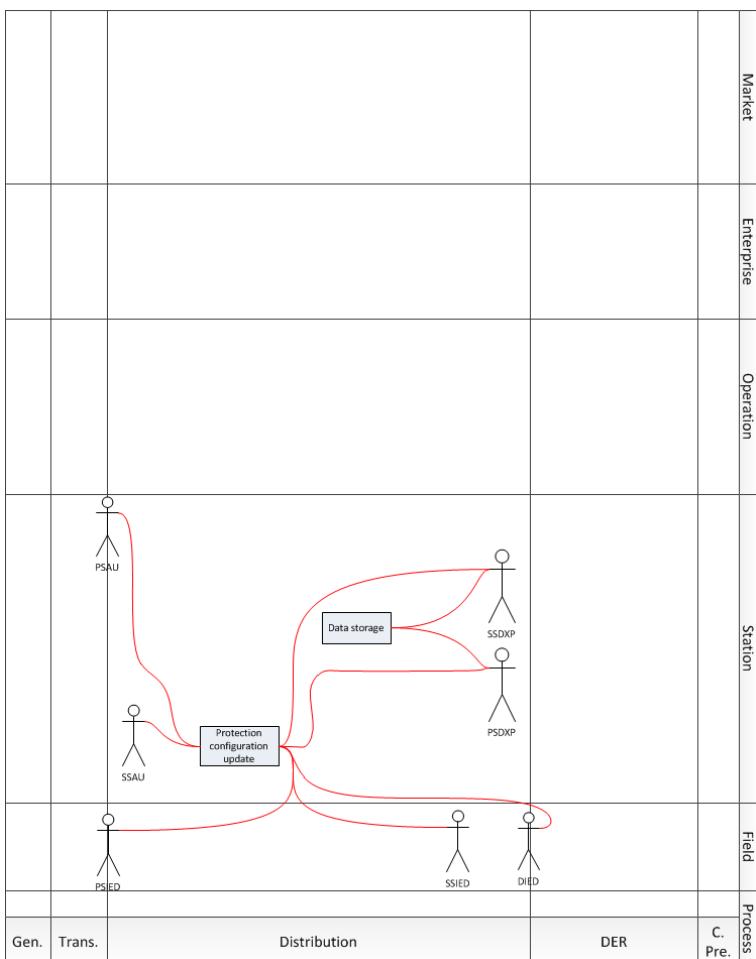
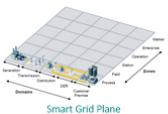


Figure A6.9: Smart Grid Plane diagram of IDE4L – Protection Configuration Update UC.

### MV Network Power Control

The goal of the MVPC UC is to evaluate the current and future states of the network by using the data series provided by the forecaster and state estimator stored in PSDXP. In coordination with the controllers on the same and different voltage levels, the MVPC, then finds a solution for the congestion situation to insure an optimal operation of the grid. The MVPC is located at primary substation level and functioning within the Primary Substation Automation Unit (PSAU).

First, the MVPC evaluates the current state of the network at  $t=0$ . If congestion is present, several algorithms will run to calculate and find an optimal solution. If no congestion is present at  $t=0$ , the controller will then evaluate the future state of the network at  $t=1....k$  and take the required precautions or the necessary actions to solve future congestions and / or running the grid optimally. To find a solution, MVPC needs access to the following information: Current grid topology, price of activating DER (PPF), Boundary conditions (are there any limits from the MV grid), DER availability (is the DER connected, what is the current state of the DER), FLISR (are there any faulted components to take into account), weather forecasts, events. After an iterative process where an acceptable solution to congestion is found, the MVPC outputs the appropriate control actions on the MV grid and LVPC controllers below it. It controls the setting

of the tap changer and the directly controlled flexible load/production (contract already made on CCPC level). The steps in the MVPC UCs are explained below:

1. The input data for MVPC, namely the demand response model, the current and forecasted states, price of activating DER (PPF), boundary conditions of the grid, DER availability, faulted components, weather forecasts, events are retrieved from the Primary Substation Data eXchange Platform (PSDXP) by the PSAU and SSAU with the functions DS.
2. The PSAU checks the state of the grid against the grid model through the function “check state electrical variables” (CSEVs).
3. If congestion (power or voltage violation) is detected in current or future states, the PSAU will act to solve the congestion, through the “control function” (CF). After an iterative process where an acceptable solution to congestion is found, the CF outputs the appropriate control actions back to the PSAU.
4. If no congestion is detected, an optimization process is performed in order to reduce operational costs, with the control function (CF).
5. The control actions are sent in terms of control signals, with the function “compute control signals” (SCSs) to the IEDs and to the SSAU. The control actions include the new topology (tap changer setting), voltage or reactive power reference points of DGs and FACTS devices, and flexible load command.

**Table A6.10: Actors and functions for MV Network Power Control use case.**

Actors	Functions
Primary Substation Automation Unit (PSAU)	Check Status of Electrical Variables (CSEV)
Secondary Substation Automation Unit (SSAU)	Control Functions (CFs)
Primary Substation Intelligent Electronic Devices (PSIED)	Compute Control Signals (SCSs)
Secondary Substation Intelligent Electronic Devices (SSIED)	Data Storage (DS)
Distributed Intelligent Electronic Devices (DIED)	
Secondary Substation Data eXchange Platform (SSDXP)	
Primary Substation Data eXchange Platform (PSDXP)	

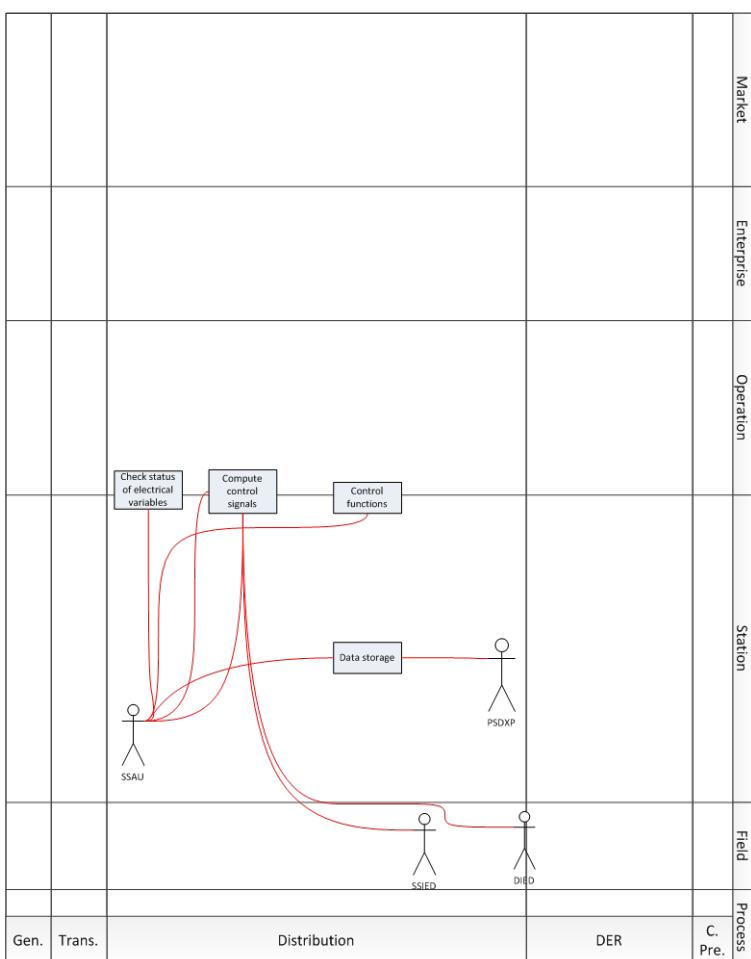
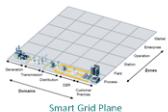


Figure A6.10: Smart Grid Plane diagram of IDE4L – MV Network Power Control UC.

### LV Network Power Control

The goal of the UCs LVPC is to evaluate the current and future states of the low voltage network by using the data series from forecaster and state estimator, stored in a Secondary Substation Data eXchange Platform (SSDXP). In coordination with the controllers on the same and different voltage levels, the LVPC finds a solution for the congestion situation to insure an optimal operation of the low voltage grid. The LVPC is located at a primary substation level and functioning within the secondary substations automation system.

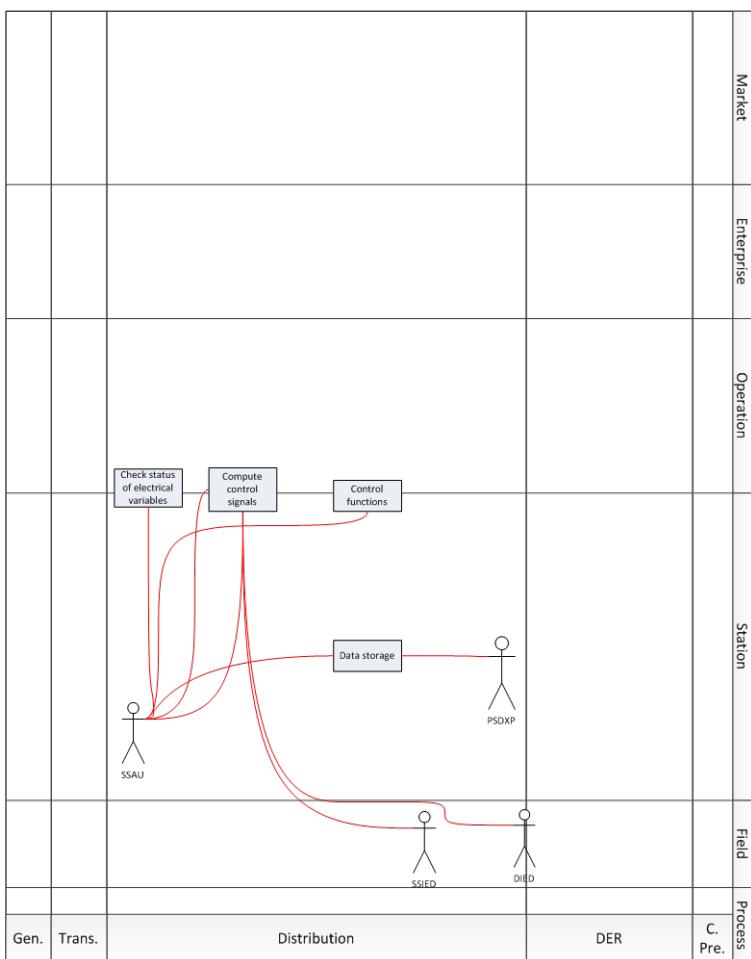
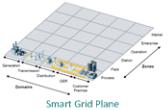
First, the LVPC evaluates the current state of the network at  $t=0$ . If congestion is present, several algorithms will run to calculate and find an optimal solution. If no congestion is present at  $t=0$ , the controller will then evaluate the future state of the network at  $t=1\dots k$  and take the required precautions or the necessary actions to solve future congestions and / or running the grid optimally. To find a solution, LVPC needs access to the following information: current grid topology, the price of activating DER (PPF), Boundary conditions (are there any limits from the MV grid), DER availability (is the DER connected, what is the current state of the DER), FLISR (are there any faulted components to take into account), weather forecasts, events. After an iterative process where an acceptable solution to congestion is found, the LVPC outputs the appropriate control actions to the IEDs.

The steps in the LVPC UC are explained below:

1. The input data for LVPC, namely the demand response model, the current and forecasted states, price of activating DER (PPF), boundary conditions of the grid, DER availability, faulted components, weather forecasts, events are retrieved from the Secondary Substation Data eXchange Platform (SSDXP) by the SSAU with the functions DS.
2. LVPA is performed. The algorithm checks the state of the grid against the grid model through the function “check state electrical variables” (CSEVs).
3. If congestion (power or voltage violation) is detected in current or future states, the MVPC algorithm will act to solve the congestion, through the “control function” (CF). After an iterative process where an acceptable solution to congestion is found, the CF outputs the appropriate control actions.
4. The control actions are sent in terms of control signals, with the function “compute control signals” (SCSs) to the IEDs. The control actions include the new topology (tap changer setting) and flexible load command.

**Table A6.11: Actors and functions for LV Network Power Control use case.**

Actors	Functions
Secondary Substation Automation Unit (SSAU)	Check Status of Electrical Variables (CSEV)
Secondary Substation Intelligent Electronic Devices (SSIED)	Control Functions (CFs)
Distributed Intelligent Electronic Devices (DIED)	Compute Control Signals (SCSs)
Secondary Substation Data eXchange Platform (SSDXP)	Data Storage (DS)



**Figure A6.11: Smart Grid Plane diagram of IDE4L – LV Network Power Control UC.**

### Control Center Network Power Control (CCPC)

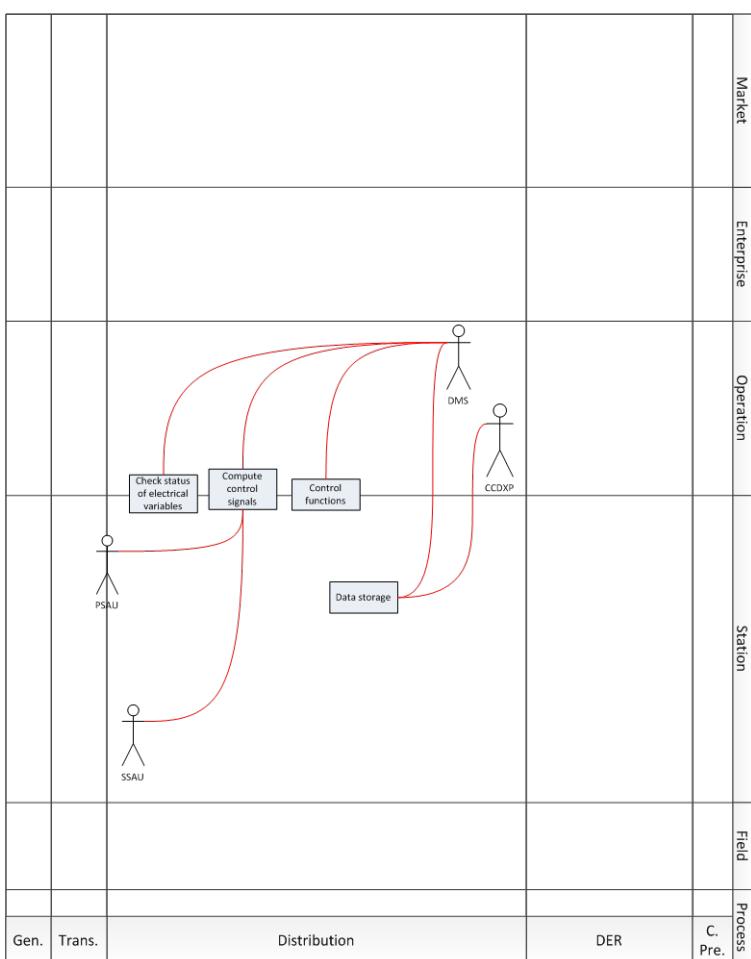
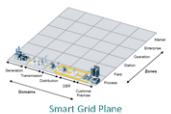
CCPC will run on fixed intervals and on-demand (in case of a fault situation) at the control center level. The objective of the CCPC is to evaluate the state of the medium voltage network and set reference points for the topology of the entire network and buy flexibility services from commercial aggregator to optimize the power flow and bus voltage magnitudes in the network. CCPC will take into consideration the current status of the network ( $t=0$ ), then if no congestions are detected, it will evaluate the future states ( $t=1\dots k$ ). The CCPC will optimize the power and voltage of the entire MV grid, satisfying the constraints for lines maximum burden and voltage security range, through changes of topology (switches/breakers) and DER utilization. The necessary data, like Current grid topology, the price of activating DER (PPF), Boundary conditions (are there any limits from the TSO), DER availability (is the DER connected, what is the current state of the DER), FLISR (are there any faulted components to take into account), for the operation of CCPC, state estimator and state forecaster are stored in a central data exchange platform (DXP) at control center level. After an iterative process where an acceptable solution to congestion is found, the CCPC outputs the appropriate control actions. The control actions include one or more of the following: the new topology, up-regulation or-down-regulation of DER, tab-positions and so on.

The steps are described below:

1. The input data for CCPC, namely the demand response model, the current and forecasted states, price of activating DER (PPF), boundary conditions of the grid, DER availability, faulted components, weather forecasts, events are retrieved from the control center DXP by the DMS with the functions DS.
2. The CCPC algorithm checks the state of the grid against the grid model through the function “check state electrical variables” (CSEVs).
3. If congestion (power or voltage violation) is detected in current or future states, the CCPC algorithm will act to solve the congestion with the function CF. This function includes:
  - optimize grid topology
  - optimize grid tariff (will be described in details in the DADT UC)
  - buy services from aggregator (described in details in the aggregator related UCs)
  - sends the necessary schedules (DER load/production, prices, weather, active/reactive power limit) to the MVPC implemented in the PSAU.
4. After an iterative process where an acceptable solution to congestion is found, the CCPC outputs the appropriate control actions to:
  - PSAU and SSAU, through the function SCSs, as far as grid topology changes;
  - Control center DXP, through the function Data storage (DS), concerning offers for buying ancillary services from commercial aggregators. In this case the output consists of flexibility tables. The commercial aggregators will receive such offers as explained in the Flexibility table use case.

**Table A6.12: Actors and function for Control Center Network Power Control use case.**

Actors	Functions
Primary Substation Automation Unit (PSAU)	Check Status of Electrical Variables (CSEV)
Secondary Substation Automation Unit (SSAU)	Control Functions (CFs)
Control Center Data eXchange Platform (CCDXP)	Compute Control Signals (SCSs)
Distribution Management System (DMS)	Data Storage (DS)



**Figure A6.12: Smart Grid Plane diagram of IDE4L – Control Center Network Power Control UC.**

### Decentralized FLISR

The use case contemplates the detection process using relevant information for different types of faults. A distributed control functions is proposed in order to locate and isolate the part of the network that has been affected by acting on circuit breakers, switches and microgrid interconnection switches located along the feeder under test. Once the fault is located and isolated, the service restoration process will start. The steps are described below:

1. When a fault happens in one of the areas covered by the feeder, IEDs distributed along the grid will detect it and will extract the fault related information as faulted phases, power flow direction, fault currents, faulted equipment, etc and send directly to peer protection IEDs and reporting it over to the central primary substation DXP. This process goes under the name of Fault information acquisition (FIA).
2. The fault detection will trigger a communication process between peer IEDs, located within the area affected by the fault and the protection function which is operating within the PSAU. The information received will be processed by each intelligent electronic device in order to determine the circuit breaker controller which is nearest the fault location. The opening of this CB will be commanded by its

corresponding intelligent electronic device, as well as the block of the opening of the other CBs located along the faulted feeder. This procedure goes under the name of fault processing (FP) function.

3. With the FIA function, the decentralized IEDs controlling switches will communicate, among them and with the PSAU, the fault related information, allowing determining a more precise faulted section area, thus reducing the isolated area. Once the system reaches a steady configuration, all final state reports are sent to the PSAU to inform about the fault location and the current state of CB and Switches.

4. For the service restoration phase, IEDs will run a fast restoration algorithm in order to minimize the outage cost. This procedure goes also under the name Fault processing (FP). Once all possible customers have been reenergized, a slow restoration algorithm will be performed in a centralized system, with the CCPC use case, in order to determine the optimum reconfiguration according to different cost functions.

5. Data regarding the FLISR process and the new topology are stored, through DS function, in the local DXPs (Primary Substation Data eXchange Platform (PSDXP)).

**Table A6.13: Actors and functions for Decentralized FLISR use case.**

Actors	Functions
Primary Substation Automation Unit (PSAU)	Data Storage (DS)
Primary Substation Intelligent Electronic Devices (PSIED)	Fault Processing (FP)
Secondary Substation Intelligent Electronic Devices (SSIED)	Fault Information Acquisition (FIA)
Distributed Intelligent Electronic Devices (DIED)	
Primary Substation Data eXchange Platform (PSDXP)	
Secondary Substation Intelligent Electronic Devices (SSIED)	

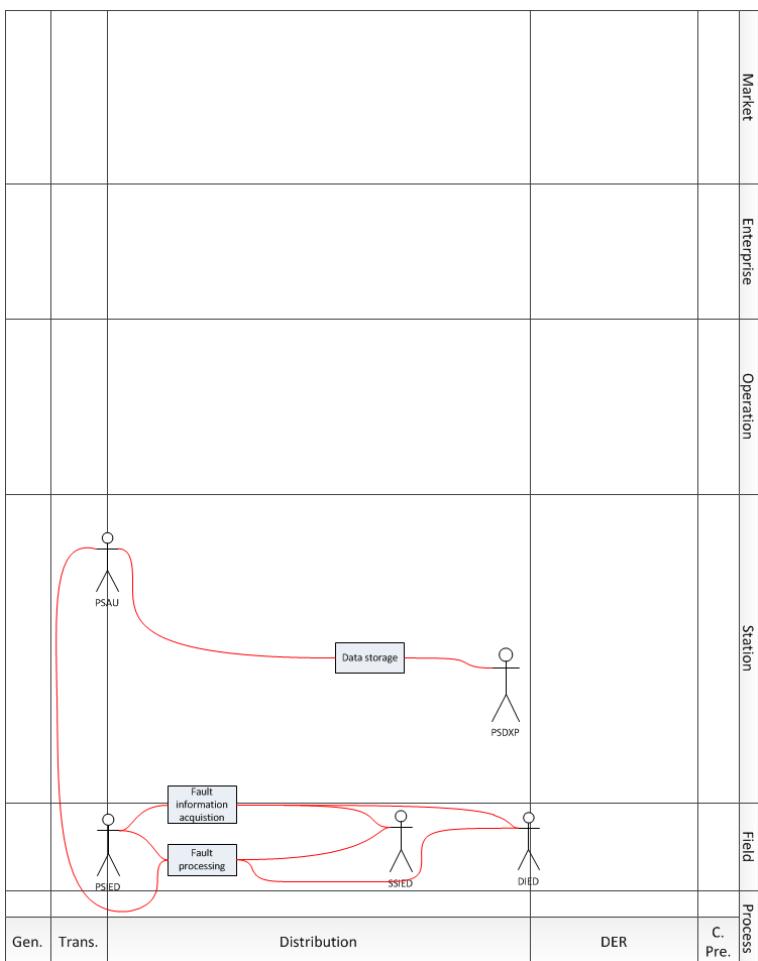
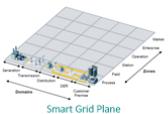


Figure A6.13: Smart Grid Plane diagram of IDE4L – Decentralized FLISR UC.

### Microgrid FLISR

This use case explains the disconnection of a microgrid from the MV distribution grid responding to a status change and analyzes the reconnection to the distribution grid after fault restoration. The isolation of microgrids will allow the continuity of the service in case of contingencies in the distribution network.

Microgrids can be classified as urban microgrids and rural microgrids, given that the main difference is the point of common coupling (PCC). Urban microgrids are typically connected on a dedicated feeder of the secondary substation, whereas the rural microgrids are connected directly to a MV line through a step-down transformer. All microgrids are connected to the distribution grid through an Interconnection Switch (IS), which in the following description is classified as an IED actor, i.e. the physical element which isolates the microgrid, which consequently defines permanently the borders of the micro grid. The IS is a smart power switch capable to detect a local (near the PCC) fault in the MV distribution grid or to receive disconnection orders from a higher level agent, such as the microgrid aggregator, the PSAU, or the DSO.

The steps are described as follows:

1. In case of contingencies in the distribution network the Microgrid central controller (MCC), sends a control signal with the function SCSs to the IEDs in order to isolates the microgrid.

2. Messages will be sent from the MCC to PSAU, with the function FIA, to inform it about microgrid status.

3. In island mode, the microgrid has its own local primary control, situated at the MCC, stabilizing the voltage and frequency of the isolated electrical area. This process requires the monitoring of electrical quantities, with measurement acquisition (MA), their checking with CSEV function, and some control algorithms, which go under the Control function “CF” set. The control actions are communicated to DERs (here classified as IEDs actors) through “compute control signals” (SCS) function.

4. During island mode, the MCC keeps on monitoring the distribution grid to detect whether the fault has been cleared or not, with the FIA function; moreover, MCC can receive inputs from PSAU indicating the fault has been cleared. These operations go under the function FIA.

5. After the fault has been cleared, the microgrid is coordinated by the microgrid secondary control, which goes under the function CF, situated at MCC level, to synchronize with the distribution grid voltage phase and frequency. IEDs are communicated to resume electrical connection with the rest of the grid, through SCS function.

6. Information about the new state of the network is stored by PSAU through DS in the PSDXP.

**Table A6.14: Actors and functions for Microgrid FLISR use case.**

Actors	Functions
Microgrid Central Controller (MCC)	Fault Information Acquisition (FIA)
Primary Substation Automation Unit (PSAU)	Control Functions (CFs)
Distributed Intelligent Electronic Devices (DIED)	Compute Control Signals (SCSs)
Secondary Substation Intelligent Electronic Devices (SSIED)	Measurement Acquisition (MA)
Primary Substation Data eXchange Platform (PSDXP)	Check Status of Electrical Variables (CSEV)
	Data Storage (DS)

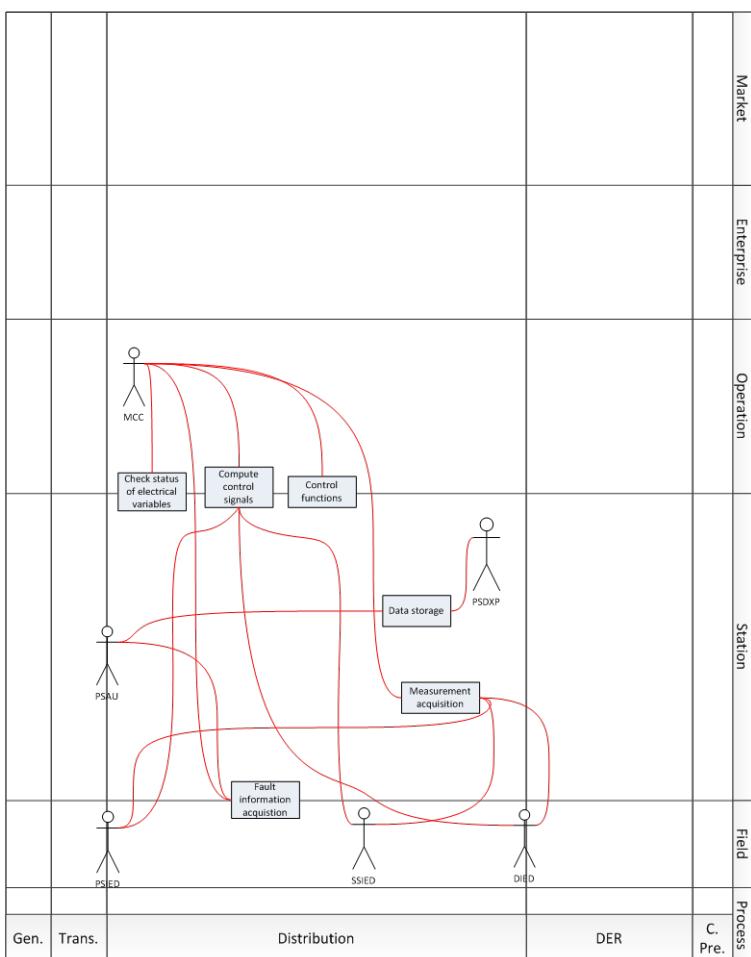
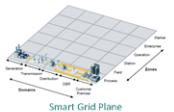


Figure A6.14: Smart Grid Plane diagram of IDE4L – Microgrid FLISR UC.

### Power Quality Control

With the aim of power quality improvement, the UC define how fast energy storage systems with high ramp power rates and short time responses are to be used so that they can rapidly exchange active and reactive power, thus smoothing power flows in LV networks and improving quality of current and voltage waveforms. To sum up, storage systems will act as active filters connected at certain point of LV/MV networks. The storage system will be the tool for an ancillary service provider for the distribution network to perform such active filtering of flicker emission in the network.

The steps are described below:

1. Data with high resolution time from power quality meter and, with low resolution time from state estimation, are extracted by PSAU and SSAU at the local DXPs, through the function DS.
2. Power quality indexes are calculated and compared with the threshold indicated by power quality standards (e.g. EN 50160), through the function CSEV.
3. In case some indexes are not satisfying control functions are run in order to obtain some effective control actions, through the function CF.

4. Control actions are sent to IEDs and to local DPXs through the function SCSs.

5. Control actions are stored by SSDXP and PSDXP with the function DS

**Table A6.15: Actors and functions for Power Quality Control use case.**

Actors	Functions
Primary Substation Automation Unit (PSAU)	Data Storage (DS)
Secondary Substation Automation Unit (SSAU)	Control Functions (CFs)
Primary Substation Data eXchange Platform (PSDXP)	Compute Control Signals (SCSs)
Secondary Substation Data eXchange Platform (SSDXP)	Check Status of Electrical Variables (CSEV)
Primary Substation Intelligent Electronic Devices (PSIED)	
Secondary Substation Intelligent Electronic Devices (SSIED)	
Distributed Intelligent Electronic Devices (DIED)	

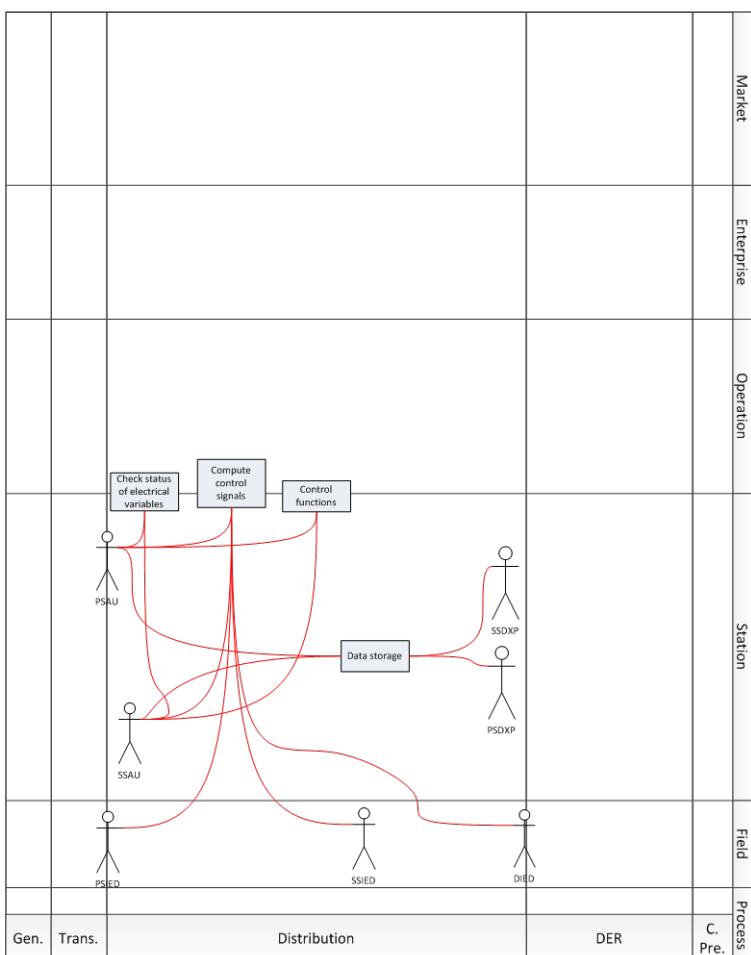
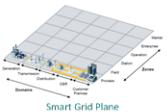


Figure A6.15: Smart Grid Plane diagram of IDE4L – Power Quality Control UC.

### Target Network Planning

The objective of the planning process is to design network structure with minimal costs for a given future generation and demand scenario. The planning will use real network data from DSOs.

The objective of this use case is determining a cost-optimal combination of smart grid components and the conventional network components (i.e. cables, overhead lines, etc.). The main technical requirements come from the voltage security, the thermal current, the short circuit current. In general, the aim is to guarantee a technically feasible network, which fulfils all operational requirements.

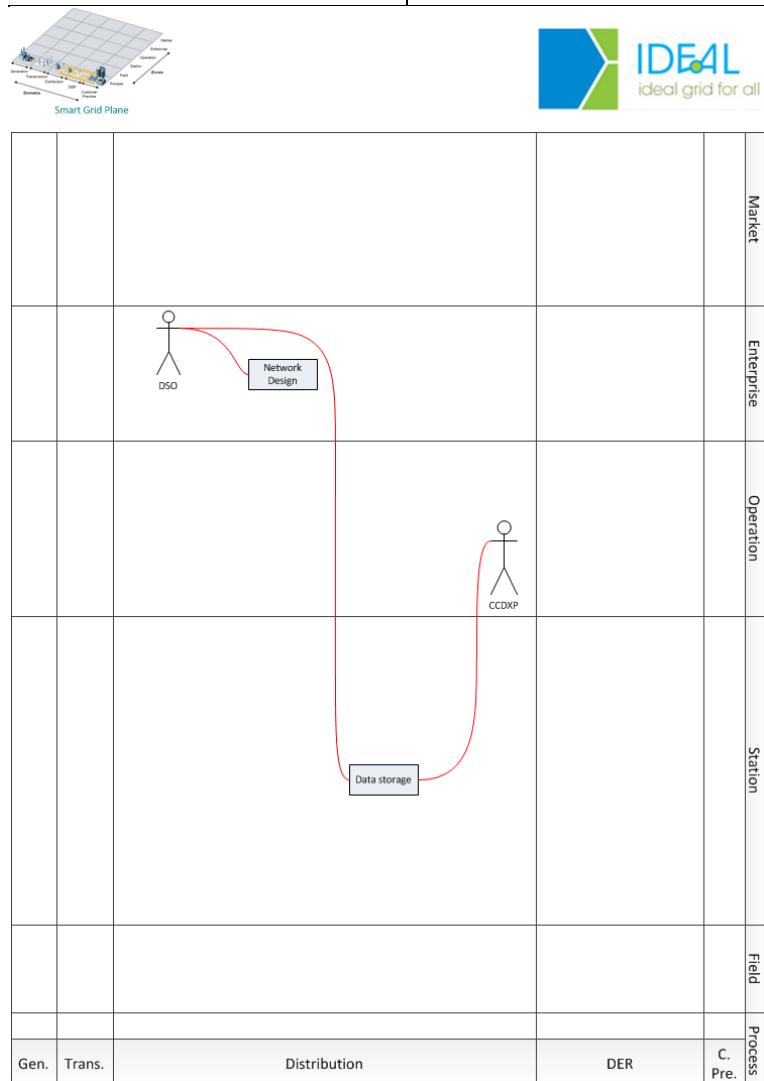
The “target network planning” concerns the cost-optimal cable, overhead line laying and the dimensioning taking account smart grid control strategies such as demand side management, reactive power management of DER, congestion management, FLISR. The task of the UC is to plan the grid model, in terms of placing transformer, to laying cables, based on economic, technical and geographic restrictions.

The steps are described as follows:

1. The DSO, who in this use case plays the role as modeler, extracts the data related to the model of the grid, customers and past reports of congestions, status of the grid etc. from the control center DXP, with the function DS.
2. Data are elaborated by the modeler, with the function network design in order to obtain forecast and statistics about congestions and price for electricity and flexibility.
4. Results of the network design are stored in control center DXP with DS.

**Table A6.16: Actors and functions for Target Network Planning use case.**

Actors	Functions
Control Center Data eXchange Platform (CCDXP)	Data Storage (DS)
Distribution System Operator (DSO)	Network Design (ND)



**Figure A6.16: Smart Grid Plane diagram of IDE4L – Target Network Planning UC.**

## Expansion Planning

Expansion planning use case determines the proper development steps from one given distribution network structure (original network) to one or more future network structures (target network). The output of the use case is the investment plan on network transitions.

The main task is to schedule and define the amount of investment steps. The starting point of the planning is the existing network infrastructure (age/condition of network, ratings, locations, etc.) and the performance of network (power quality, quality of supply, etc.). Because target network plan is considering very long term forecasts (30-40 years ahead), there will be investment needs for network due to aging of network, connection of new customers, increased loading of components, and regulatory requirements to improve system performance. The UC is valid for every target network plan and repeated annually in case of changing forecasts of environment.

The UC consists in the following steps:

1. The data produced by target network planning UCs are extracted from the control center DXP with the function DS.
3. The models of existing distribution network, customers, production units and control capabilities are extracted by means of function NIA and CIA, with the participation of the actors NIS, WDP, CIS, DMS, AMS and stored in the control center DXP with DS function.
3. DER scenarios are evaluated by the DSO, with the function Scenario forecasting and stored in the control center DXP with the function DS.
4. The DSO in the role of the “Expansion network planner” formulates the expansion planning problem for expansion scheduling process based on information from three previous steps, with the function Expansion scenario forecasting (ESP). Expansion scheduling process calculates the optimal sequence of development steps to reach target network plans.
5. Such a plan is stored in the control center DXP with the function DS.

**Table A6.17: Actors and functions for Expansion Planning use case.**

Actors	Functions
Control Center Data eXchange Platform (CCDXP)	Scenario Forecasting (SF)
Distribution System Operator (DSO)	Network Information Acquisition (NIA)
Distribution Management System (DMS)	Expansion Scheduling Process (ESP)
Asset Management System (AMS)	Customer Information Acquisition (CIA)
Weather Data Provider (WDP)	Data Storage (DS)

Network Information Service (NIS)	
Customer Information Service (CIS)	

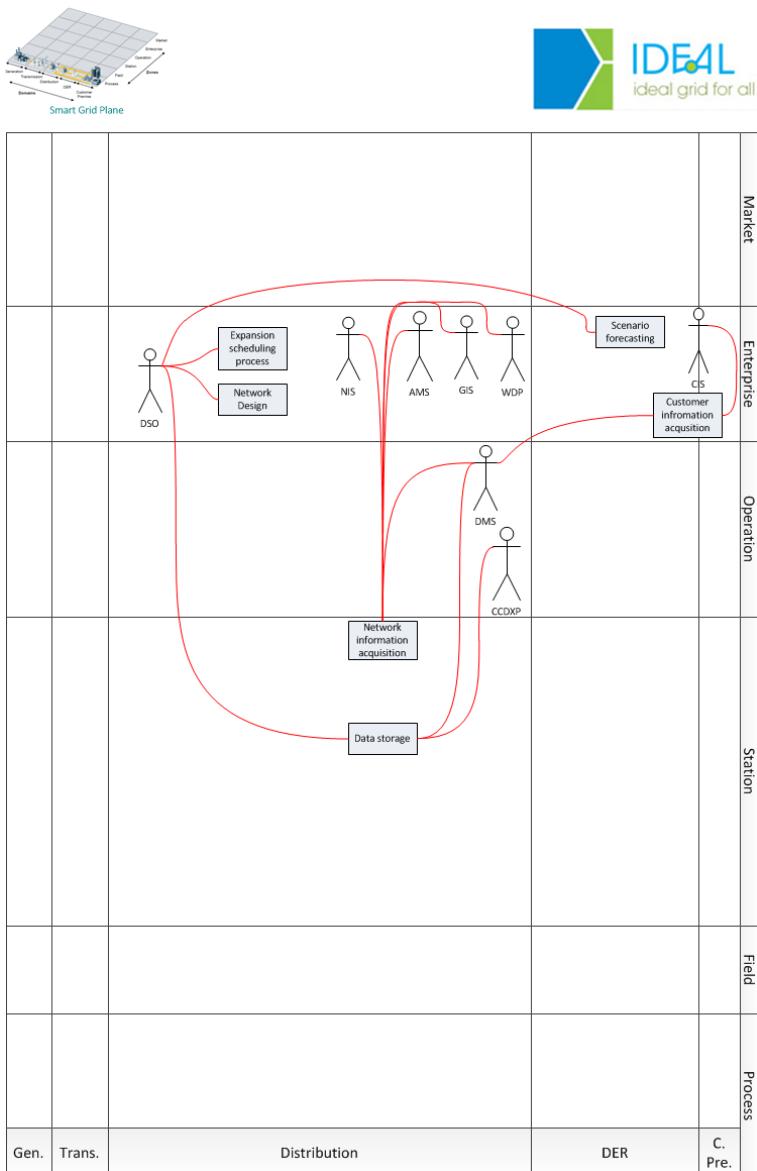


Figure A6.17: Smart Grid Plane diagram of IDE4L – Expansion Planning UC.

### Load Areas Configuration

This use case shows the interaction between the TSO and the DSOs (DSO act in the role of technical aggregator, consequently the name technical aggregator will be used hereafter) and between the technical aggregators and the commercial aggregators, required to assign the macro load areas/load areas/prosumers properly. This configuration process is performed to include new prosumers in the aggregation portfolio and should be updated periodically. The function of the load area is to group

prosumers in terms of consumption pattern, impedance value, prosumer connectivity, and other parameters to be considered by the DSO. The steps of the UC are the followings:

1. The TSO assigns each (technical aggregators') load area to a macro load area, with the function Load area configuration, and communicates this information to the technical aggregators.
2. The status of the prosumer, in terms of nominal active and reactive power, storage capacity and price for flexibility, is obtained from the DMS, with the function Flexibility and DER status acquisition (FDA), from the HEMSS, and stored with the data storage (DS) function, at the control center DXP.
3. The DSO assigns each prosumer to a load area, using the data from step 2, with the function Load area configuration, and communicates this information to the commercial aggregators (Assumption: the technical aggregator has the knowledge of which low voltage consumer is in the portfolio of each commercial aggregator; this is done off-line and would not be part of this use case).

**Table A6.18: Actors and functions for Load Areas Configuration use case.**

Actors	Functions
Commercial Aggregator (CA)	Load Area Configuration (LAC)
Transmission System Operator (TSO)	Flexibility and DER Status Acquisition (FDA)
Distribution System Operator (DSO)	Data Storage (DS)
Home Energy Management System (HEMS)	
Distribution Management System (DMS)	
Control Center Data eXchange Platform (CCDXP)	

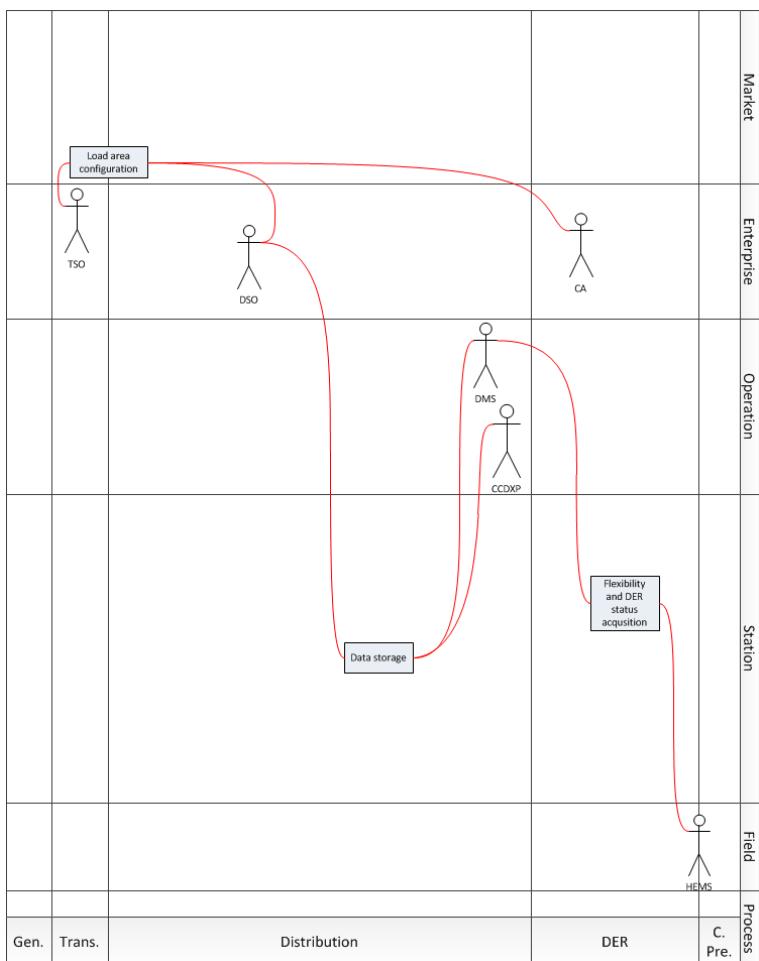
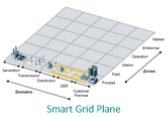


Figure A6.18: Smart Grid Plane diagram of IDE4L – Load Areas Configuration UC.

### Flexibility Table

This use case shows the interaction between the TSO and the technical aggregators, and between the technical aggregators and the commercial aggregators, required to exchange the flexibility tables before participating in the flexibility markets. Using the concepts of load areas and macro load areas for the validation processes (see Load Areas Configuration Use Case) the goal of providing commercial aggregators with flexibility tables is to: 1. Define how much flexibility is allowed for each load area over the time. 2. This information is used as guidance to the Aggregators for planning the bidding according to the Network constraint. Steps of the UC are:

1. The TSO calculates flexibility tables for macro load areas and send them to technical aggregators before each bidding process, to indicate the scope within which the aggregators can bid for.
2. The technical aggregator calculates flexibility tables for load areas and sends them to the commercial aggregators before each bidding process, to indicate the scope within which the commercial aggregators can bid for.
3. The Flexibility tables are provided to the commercial aggregator through its commercial aggregator DXP, with the function DS.

Table A6.19: Actors and functions for Flexibility Table use case.

Actors	Functions
Commercial aggregator Data eXchange Platform (CADXP)	Flexibility Tables (FTs)
Transmission System Operator (TSO)	Data Storage (DS)
Distribution System Operator (DSO)	

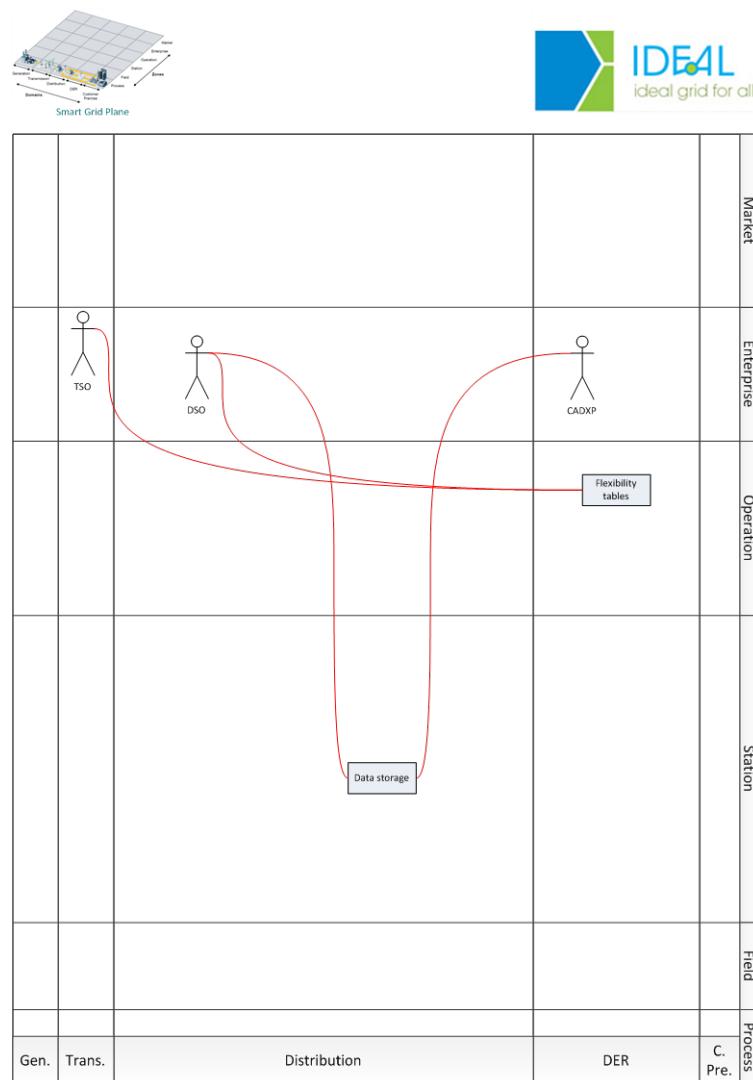


Figure A6.19: Smart Grid Plane diagram of IDE4L – Flexibility Table UC.

### Commercial aggregator asset planning

This UC describes the operation of the commercial aggregator in order to evaluate the capacity of the DERs within its load area to perform scheduled Re-profiling (SRP) and conditional Re-profiling (CRP) actions (later described), then to match this availability with the requirements of the TSOs and technical aggregator

contained in the flexibility tables and finally to send the bids of SRPs and CRPs to the market. SRP is the offer of one or more DERs to produce an assigned power during an assigned period of time, meanwhile CRP is the offer of one or more DERs to be ready and available to change the output power in a certain range for an assigned period of time. The commercial aggregator cannot access to the property information of the DSO, for security reasons, namely the need for reservation of key information as the weaknesses of the grid. However, it receives from the technical aggregator the flexibility tables that represent the scope within the commercial aggregator can bid for. Furthermore, in the view of developing a concept closer to a free market, the commercial aggregator can access the information of the HEMS within its load area and can use forecast services, weather forecast agencies reports, and in general, information from external providers in order to optimize the schedules of the DERs belonging to its load area. The designed process consists in the following steps:

1. Information about the customers of the commercial aggregator is retrieved periodically, with the function Flexibility and DER Status Acquisition (FDA) from the HEMSS and stored in the commercial aggregator DXP with the function DS. The same is done for forecasts for the production of the DERs and the demand obtained from external entities.
2. The flexibility tables, sent by the technical aggregator, are retrieved by the commercial aggregator with the function data storage from the commercial aggregator DXP, with the function data storage (DS).
3. The commercial aggregator, taken into consideration the data from the customer, the forecast and the flexibility tables, calculates the optimal scheduling for the resources and customers that it manages, with the function compute schedule.
4. The commercial aggregator submits a bid to the market operator, with the function Bid submission.

**Table A6.20: Actors and functions for Operational Planning use case.**

Actors	Functions
Market Operator (MO)	Data Storage (DS)
Commercial aggregator Data eXchange Platform (CADXP)	Bid Submission (BS)
Commercial Aggregator (CA)	Compute Schedule (CS)
	Flexibility and DER Status Acquisition (FDA)

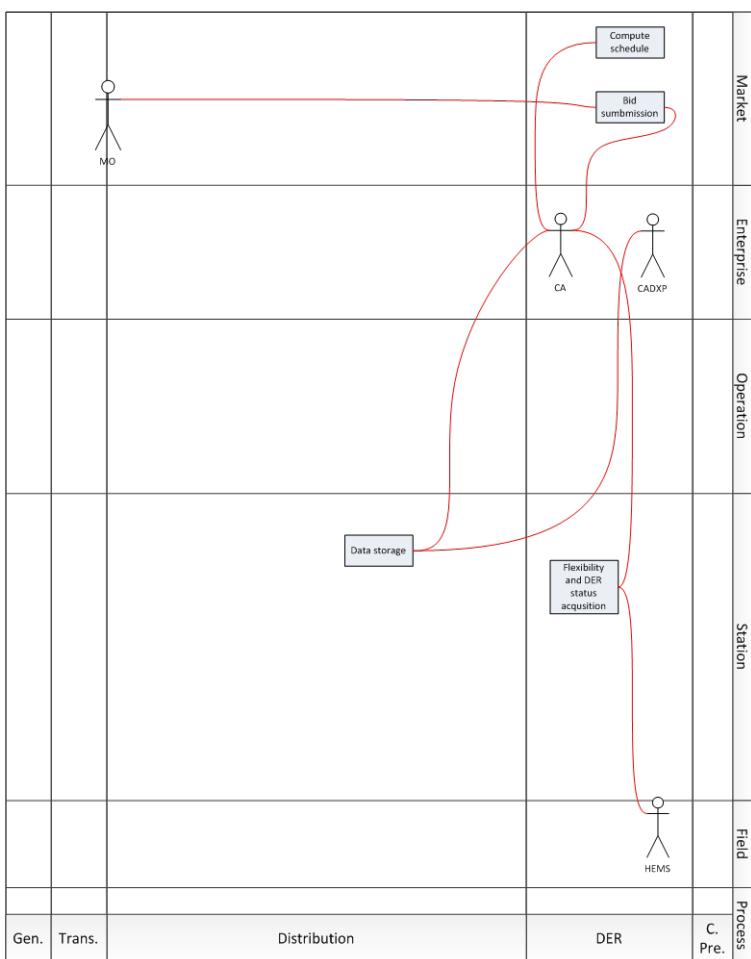
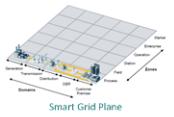


Figure A6.20: Smart Grid Plane diagram of IDE4L – Commercial aggregator asset planning UC.

### SRP and CRP Day-Ahead and Intra-Day Market Procurement

This UC explains the market trading of SRP and CRP products for the day-ahead and intra-day energy markets, where the aggregator will have the obligation to provide a specified demand modification (reduction or increase) at a given time to a flexibility buyer. The interactions of the flexibility buyers (BRPs, DSOs, TSOs, etc.) and suppliers (commercial aggregators) with the market operator (MO) so as to enable market clearing for SRP and CRP products in the day-ahead and intra-day market are shown.

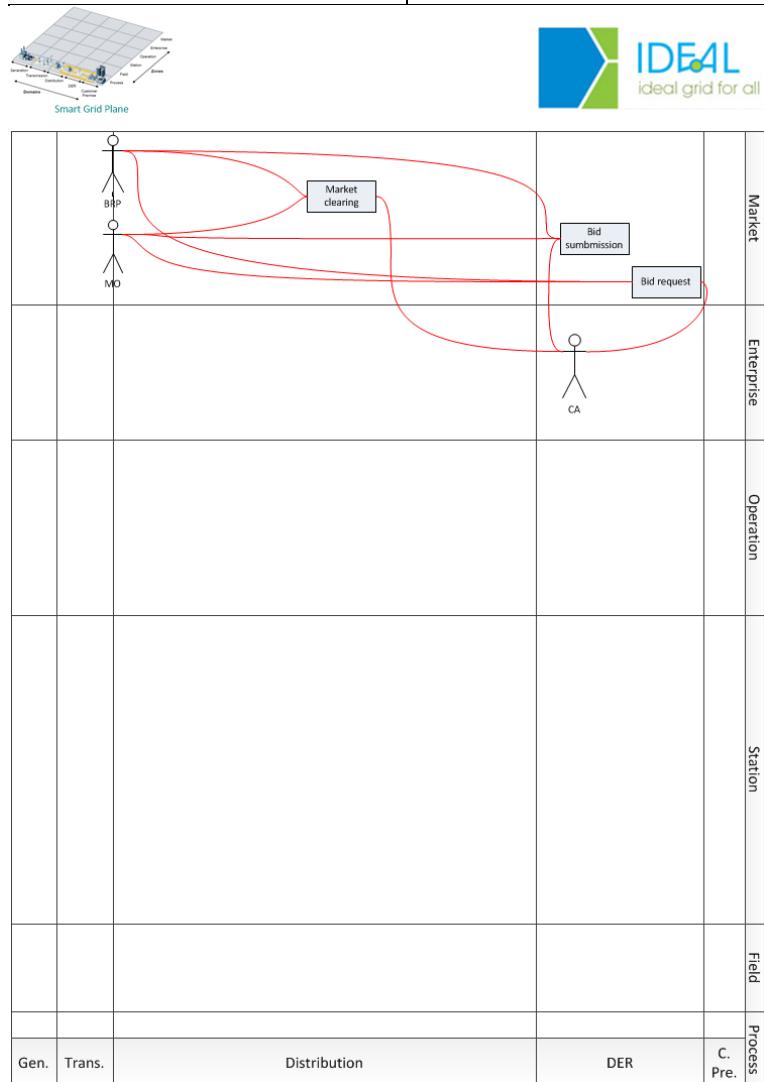
The MO will send a bidding process creation message to flexibility providers/buyers before the gate opens for the day-ahead or intra-day market. In between gate opening and gate closure of the market, flexibility bids will be taken into consideration during the clearing phase. Flexibility buyers/providers will submit flexibility bids to be considered during the market clearing phase. These bids should be sent during the gate opening period. One message will be sent for each load area for which the service is required/offered. Finally the market will clear itself to work out the set of accepted bids and the market clearing price. This information will be published by the MO to inform the flexibility buyers/providers about the market clearing price and the bidding acceptance. For those accepted bids, the possible modifications on the accepted volume will be also communicated.

The steps within this UC are the followings:

1. MO sends the request for bid to both BRPs and CAs, with Bid Request function.
2. Flexibility bids are sent to MO with Bid submission function and taken into consideration by MO.
3. MO takes care of the market clearing: assuring that demand = offer.
4. Market clearing price is communicated to BRPs and CAs.

**Table A6.21: Actors and functions for Day-Ahead and Intra-Day Market Procurement use case.**

Actors	Functions
Commercial Aggregator (CA)	Bid Request (BR)
Market Operator (MO)	Bid Submission (BS)
Balance Responsible Party (BRP)	Market Clearing (MC)



**Figure A6.21: Smart Grid Plane diagram of IDE4L – Day-Ahead and Intra-Day Market Procurement UC.**

### Conditional re-profiling activation (CRP Activation)

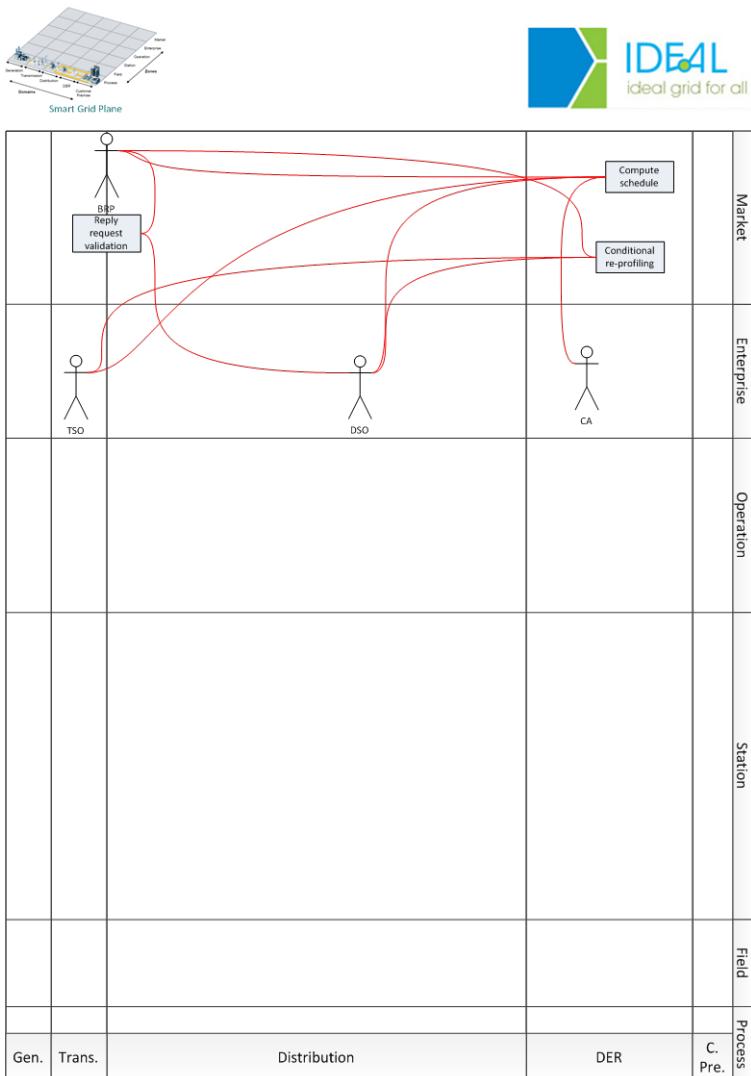
This UC describes how the commercial aggregator provides a specified load profile modification (reduction or increase) during a given period. The delivery is called upon by the buyer of the flexibility product (similar to a reserve service). A flexibility buyer (BRP, technical aggregator, TSO, etc.) identifies the need to activate a previously settled CRP product for balancing and/or congestion management proposes. The flexibility buyer needs to send an explicit signal to the aggregator, telling that the CRP product needs to be activated. CRPs were previously validated by the Off-Line Validation (OLV). The DSO Real Time Validation (RTV) process has to approve the CRP activation request before its activation.

These are the steps of the UC:

1. A flexibility buyer (BRP, DSO, TSO) identifies the need to activate a previously settled CRP product for balancing and/or congestion management proposes, with the function Conditional re-profiling (CRP).
2. CRPs were previously validated by the Off-Line Validation (OLV). The DSO Real Time Validation (RTV) process has to approve the CRP activation request before its activation. A message is sent from the MO to the DSO to ask for the real time validation with the function Reply/request validation.
2. The flexibility buyer needs to send an explicit signal to the commercial aggregator, telling that the CRP product needs to be activated, with the function Compute schedule (CS).

**Table A6.22: Actors and functions for Conditional re-profiling activation (CRP Activation) use case.**

Actors	Functions
Commercial Aggregator (CA)	Conditional Re-Profiling (CRP)
Balance Responsible Party (BRP)	Compute Schedule (CS)
Transmission System Operator (TSO)	
Distribution System Operator (DSO)	



**Figure A6.22: Smart Grid Plane diagram of IDE4L – Conditional re-profiling activation (CRP Activation) UC.**

## Off-Line Validation

This use case shows the interaction between the aggregators and the technical aggregators, and the technical aggregators and the TSO, required to validate technical feasibility of the bids resulting from the market clearing process. It is used for Day-Ahead and Intra-day Market Validation. The validation takes place in fixed steps (15 minutes steps) rather than over the whole day-ahead period. If flexibility products are not feasible during a time slot, they will be curtailed with disregard of the results for another time slot. These are the steps of the UC:

1. Requests for validation are sent from MO to TSO and technical aggregator.
  2. TSO and technical aggregator perform power flow analysis to verify if the voltage and branch capacity constraints are satisfied with the CESV. The technical aggregator uses the grid data from the control center DXP, extracted with the function data storage.
  3. If some violations are found, some control functions (CFs) run in order to quantify the curtailment of AD that is necessary.

4. TSO and technical aggregator will reply asking for a Curtailment of the active demand product or reply acceptance.

5. The new schedule is sent to CA with compute schedule function.

**Table A6.23: Actors and functions for Off-Line Validation use case.**

Actors	Functions
Commercial Aggregator (CA)	Data Storage (DS)
Transmission System Operator (TSO)	Request/Reply Validation (RRV)
Distribution System Operator (DSO)	Check Status of Electrical Variables (CSEV)
Control Center Data eXchange Platform (CCDXP)	Control Functions (CFs)
Market Operator (MO)	Compute Schedule (CS)

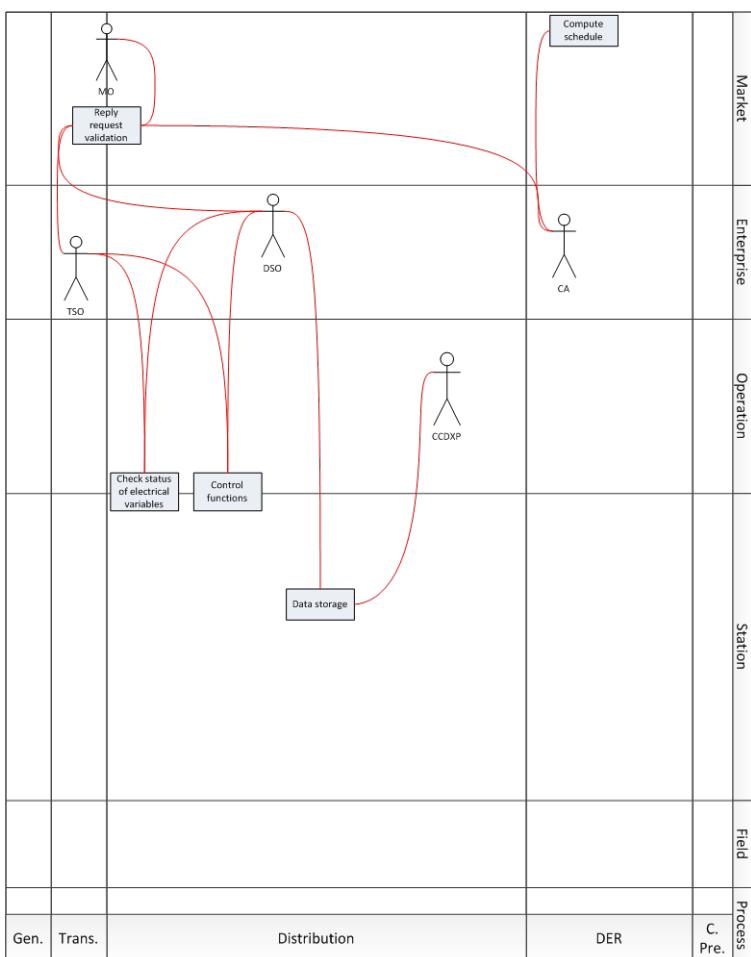
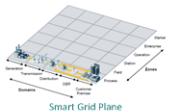


Figure A6.23: Smart Grid Plane diagram of IDE4L – Off-Line Validation UC.

### Real-Time Validation

This use case shows the interaction between the aggregators and the technical aggregators required to validate the technical feasibility of the activation CRPs previously validated by the Off-Line Validation (OLV) whose activation is required, and SRP products traded in the markets with close to deployment gate closure (intra-day markets). RTV UC re-checks the feasibility of CRPs previously validated by the Off-Line Validation (OLV), whose activation is required; SRP products traded in the markets with close to deployment gate closure; but NOT the SRP products already validated by OLV which are considered activated.

The Power Flow algorithm runs to evaluate if the network constraints are met (congestion/overload and voltage limits). It uses the Network Model and the output of State Estimator. In case some constraints are violated, the Power Control is called to identify possible corrective actions in order to make the AD product feasible, such as changing tap ratio, switching shunts or SVCs, re-dispatching available DGs, Curtailing flexibility products.

These are the steps of the UC:

1. Request for real time validation sent from BRP, TSO or DSO is received by TSO and technical aggregator, with RRV function, regarding CRPs previously validated by the Off-Line Validation (OLV) and SRP products traded in the markets with close to deployment gate closure (intra-day markets).
2. TSO and DSO perform power flow analysis to verify if the voltage and branch capacity constraints are satisfied with the CESV. The technical aggregator uses the grid data from the control center DXP, extracted with the function data storage.
3. If some violations are found some control functions (CFs) run in order to quantify the curtailment of AD that is necessary.
4. TSO and technical aggregator will reply asking for a Curtailment of the active demand product or reply acceptance.
5. The new schedule is sent to CA with compute schedule function.

**Table A6.24: Actors and functions for Real-Time Validation use case.**

Actors	Functions
Commercial Aggregator (CA)	Data Storage (DS)
Transmission System Operator (TSO)	Control Functions (CFs)
Distribution System Operator (DSO)	Compute Schedule (CS)
Control Center Data eXchange Platform (CCDXP)	Check Status of Electrical Variables (CSEV)
Market Operator (MO)	Request/Reply Validation (RRV)

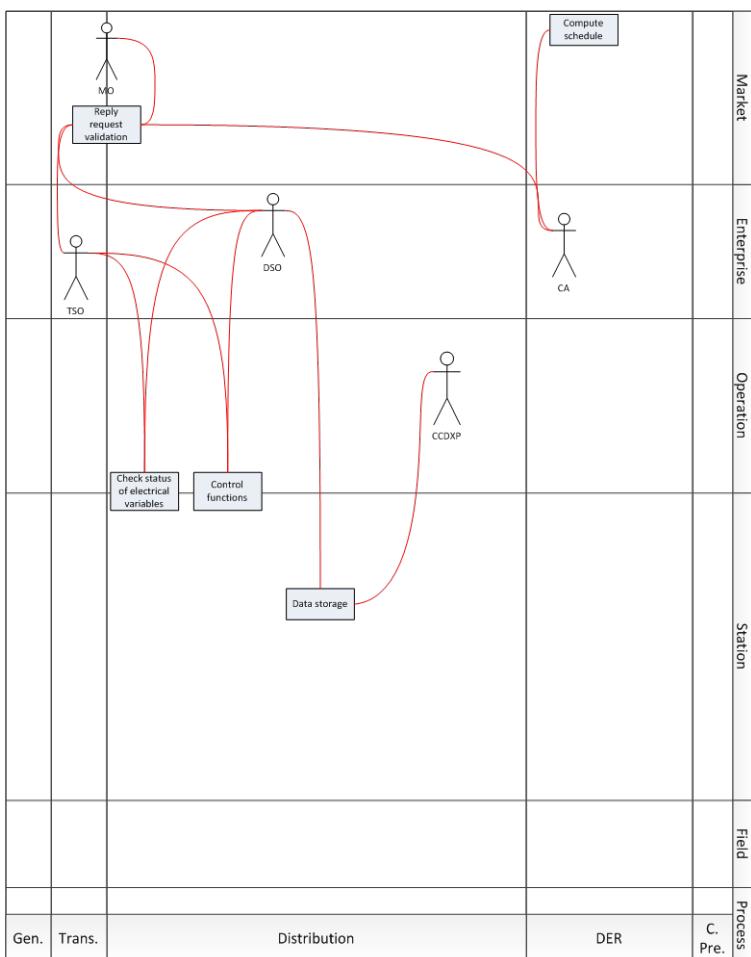
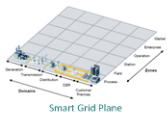


Figure A6.24: Smart Grid Plane diagram of IDE4L – Real-Time Validation UC.

### Day-Ahead Dynamic Tariff

The day-ahead dynamic tariff algorithm is to determine a day-ahead grid tariff to alleviate the forecasted congestion in the day-ahead time frame induced by the demand. The assumption made here is that the DMS has rights to determine the day-ahead grid tariff before aggregators (retailers) submit their final energy bids into the day-ahead electricity market. The day-ahead grid tariff is on top of the fixed grid tariff and the day-ahead grid tariff is purely for alleviating predicted congestion within distribution networks caused by demand. The Day-Ahead Dynamic Tariff is an alternative method that can be used parallelly with the trade of SRPs and CRPs. The congestion, in this context, is power component overloading. The input data are the customer day-ahead energy plan based on the predicted day-ahead energy prices and local production forecast, the grid topology and the grid model. The DADT algorithm runs optimal power flow to determine the day-ahead dynamic tariff to influence the flexible demands by putting an extra cost of electricity delivery. The determination of the grid tariff can be done in different manners, i.e. use an iterative process to determine a single price for the whole network to alleviate congestion or distribution locational marginal prices.

Steps in the DADT are as follows:

1. The DMS reads from the control center data exchange platform (CCDXP) the predicted system day-ahead energy prices and the day-ahead energy planning of inflexible demands, which were previously stored with the DS function.
2. The DMS sends to the CADXP the predicted day-ahead system price.
3. The commercial aggregator calculates the preliminary energy planning of flexible demands, with compute schedule function in the control center data exchange platform (CCDXP) with the DS function.
4. The DMS determines the day-ahead tariffs for the distribution network to alleviate congestion with the DAT function, they are sent to the commercial aggregator DXP with the DS function.
5. The schedules are sent from the CADXP to the HEMS with the “Compute schedule” function.

**Table A6.25: Actors and functions for Day-Ahead Dynamic Tariff use case.**

Actors	Functions
Commercial Aggregator (CA)	Data Storage (DS)
Control Center Data eXchange Platform (CCDXP)	Day ahead tariffs (DAT)
Distribution Management System (DMS)	Compute schedule (CS)
Commercial aggregator Data eXchange Platform (CADXP)	

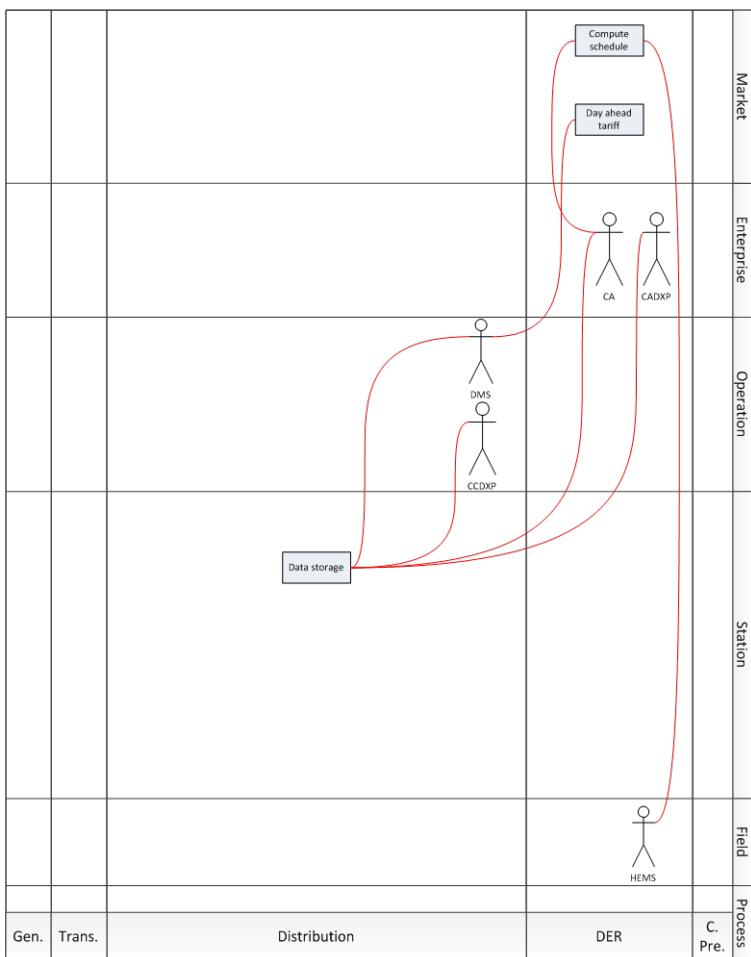
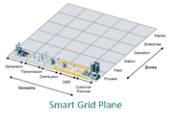


Figure A6.25: Smart Grid Plane diagram of IDE4L – Day-Ahead Dynamic Tariff UC.

### Day-Ahead Demand Response

The objective of the day-ahead demand response is to generate an optimal demand schedule of a predefined time horizon, i.e. the next operation day (24 hours). The DMS exploits the demand response UC results in the CCPC use case. Steps in the Day-ahead demand response are as follows:

- 1 The DMS receives input data, such as system price forecast, dynamic tariff (DT), weather forecast (temperature), EV driving pattern forecast, (driving distances, arriving or leaving times), and consumer requirements on house temperature from the control center data exchange platform (CCDXP) with the DS function.
2. Then, the DMS runs the optimization model, where the energy demands, comfort requirements of the customers and the availability of the flexible demands are included as constraints and the cost is the objective function. The output is the schedule for the DERs, which minimize the cost of management of the grid (e.g. minimize losses and use of assets) and the constraints are the security limits against congestions.
3. The optimal demand plan found in step 2 will be sent to the CCDXP.

Table A6.26: Actors and functions for Day-Ahead Demand Response use case.

Actors	Functions
Distribution Management System (DMS)	Data Storage (DS)
Control Center Data eXchange Platform (CCDXP)	Optimization Model (OM)

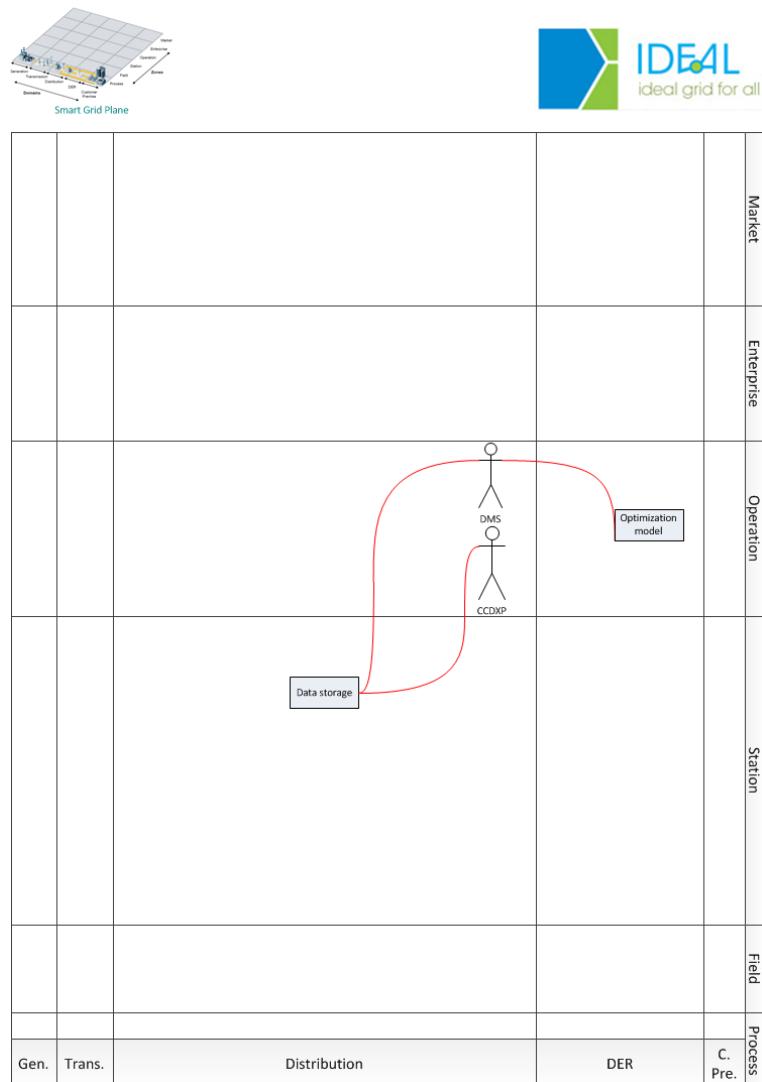


Figure A6.26: Smart Grid Plane diagram of IDE4L – Day-Ahead Demand Response UC.

## Annex 7 – INTEGRIS Use Cases

### LV01 and LV02 monitoring (LV network monitoring)

#### Short description

The use case describes monitoring process for LV network.

#### Scope

Real-time monitoring of LV network is based on measurements from smart meters of customer connection points (voltages, currents, active and reactive power), power quality meters of selected nodes (THD, flicker, V2/V1, V0/V1, 3<sup>rd</sup>, 5<sup>th</sup> and 7<sup>th</sup> harmonic and voltage sag), and DER meters of controllable DERs (voltages, currents, active and reactive power).

#### Objectives

Real-time monitoring of customer connection points, real-time monitoring of power quality indexes, real-time monitoring of DERs, and storage of monitoring data to secondary substation PC.

#### Business Objective

Real-time and extensive monitoring of distribution network provides more accurate understanding of the electrical state of the grid. It enables pinpointing investments where are really needed as opposed to spreading capital and operating costs evenly. It provides also real-time visibility to LV network to manage power flows and service quality in the network.

#### Complete Narrative

The use case describes how measurement data from customer connection points (smart meters), selected nodes (power quality meters) and DERs (DER meters) is collected and finally stored to secondary substation PC.

First each meter measures required quantities and computes average values. Then the collection of measurements is realized. Home gateway device, which could also host HEMS functionalities, is a gateway for power quality meter and DER meter. Smart meter is a gateway device towards secondary substation automation and therefore it request data from home gateway. All measurement data is requested by meter data collector located at secondary substation from smart meters. Finally data is requested to PC located also at secondary substation and stored to local database.

#### Step Analysis:

1. DM collects averaged measurements
2. PQM collects PQ indexes
3. SM collects averaged measurements
4. PQM sends data to HGW
5. HGW collects averaged measurements from DM
6. HGW publishes the data collected (step 1 and 2) via Proprietary HTTP API
7. SM requests data from HGW using Proprietary HTTP API
8. SM and HGW values are stored in the SM
9. MDC request the data from SM using DLMS private OBIS

10. SM provides the requested data to MDC using DLMS

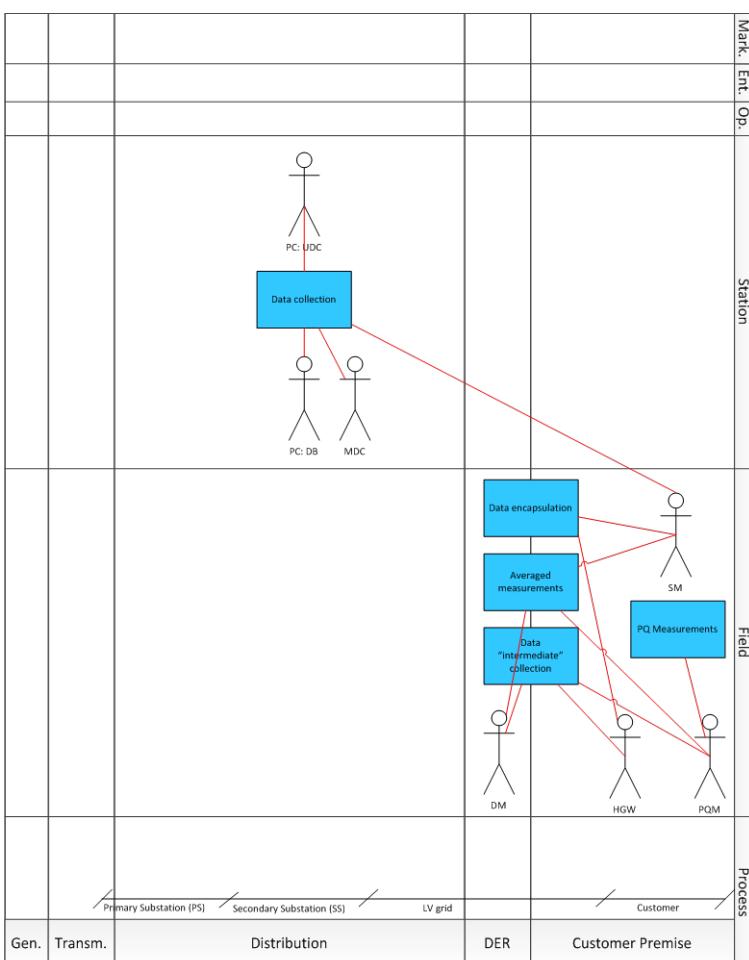
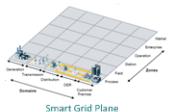
11. PC:UDC request the data to the MDC through SOAP interface, this data is stored in the PC database

Actors:

Short Name	Description
PQM	Power Quality Meter
HGW	Home Gateway
SM	Smart Meter
MDC	Meter Data Collector
PC:UDC	User Data Collector (in secondary substation PC)
PC:DB	Database (in secondary substation PC)
DM	DER meter

Functions:

Short Name	Description
Data collection	Data is requested from a client.
Data encapsulation	SM and HGW data is encapsulated into DLMS message.
Averaged measurements	Moving window average value of instantaneous values of measurement device are calculated.
Data “intermediate” collection	Data is received or requested from measurement devices.
PQ measurements	



**Figure A7.1: Smart Grid Plane diagram of INTEGRIS – LV01 and LV02 monitoring (LV network monitoring) UC.**

MV03 monitoring (MV/LV substation monitoring)

## **Short description**

The use case describes monitoring process for mean values and PQ indexes from MV/LV feeders and busbars in secondary substation.

## Scope

Real-time monitoring of MV and LV feeders and busbars in the secondary substation is based on measurements from Remote Terminal Unit connected to different type of sensors (phase/line voltages, phase currents, active and reactive power, THD, V<sub>2</sub>/V<sub>1</sub>, V<sub>0</sub>/V<sub>1</sub>).

## Objectives

Real-time monitoring MV and LV feeders and busbars in the secondary substation and storage of data to secondary substation PC.

## **Business Objective**

Real-time and extensive monitoring of distribution network provides more accurate understanding of the electrical state of the grid. It enables pinpointing investments where are really needed as opposed to spreading capital and operating costs evenly. It provides also real-time visibility to LV network to manage power flows and service quality in the network.

### Complete Narrative

The use case describes how measurement data from lines and busbars of a secondary substation can be collect and finally stored to secondary substation PC.

The RTU collect data both different types of sensors and encapsulate them according to the Modbus protocol. The RTU sends the data to the protocol gateway which translates them in IEC61850 standard. The data are finally sent to the substation PC and stored in the DB.

Step Analysis:

1. RTU collects averaged measurements
2. RTU sends measurements using ModBus to Protocol gateway (PGW) to translate to IEC 61850
3. PGW send IEC 61850 measurements to PC:RTUDC if there is a change in the data measured, these data are stored in the PC database

Actors:

Short Name	Description
PC:RTUDC	Process handling the collection of data from the protocol gateway and their store in the database
PC:DB	Final location where data are stored
PGW	Device translating the Modbus protocol in IEC61850 standard
RTU	Unit which collects data sensors and encapsulate them in Modbus

Functions:

Short Name	Description
RTU data collection	The PC request data from the PGW and store them in the DB
Measuring	Data are collected from sensors and translated in IEC61850 by the PGW

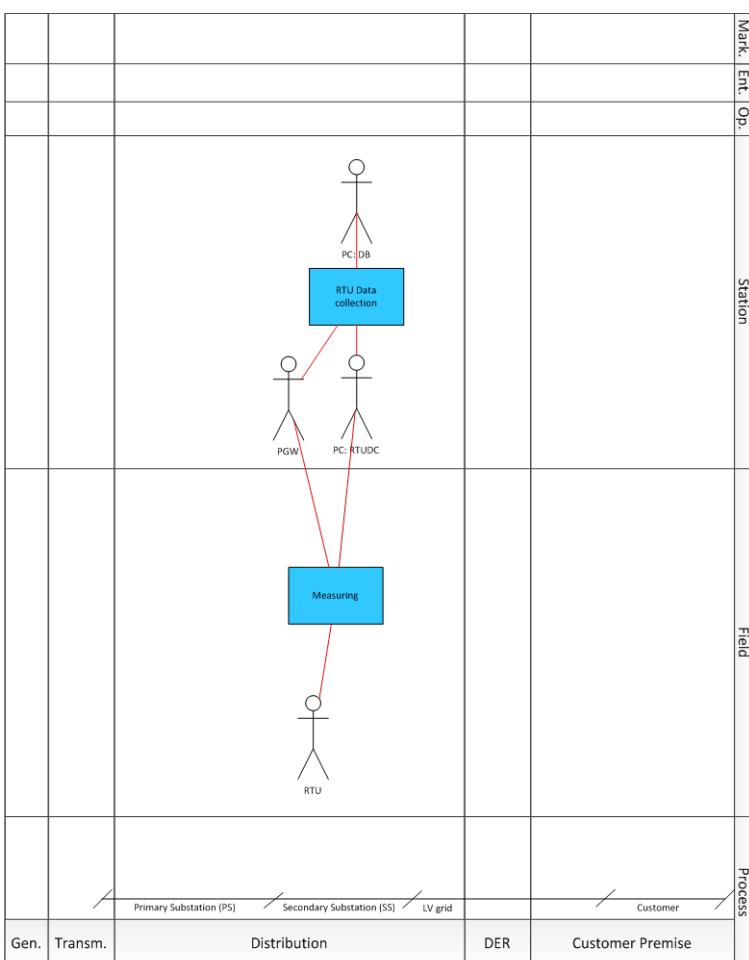
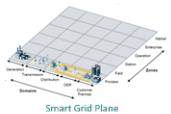


Figure A7.2: Smart Grid Plane diagram of INTEGRIS – MV03 monitoring (MV/LV substation monitoring) UC.

## LV01+LV02+MV03 (reporting MV/LV substation and LV measures to SCADA)

### Short description

Reporting secondary substation and LV network measures to SCADA.

### Scope

Reporting secondary substation and LV network measures to SCADA.

### Objectives

Reporting of measurements with fixed frequency to SCADA, and alarming to SCADA if measured values exceed alarm limits.

### Business Objective

Real-time and extensive monitoring of distribution network provides more accurate understanding of the electrical state of the grid. It enables pinpointing investments where are really needed as opposed to spreading capital and operating costs evenly. It provides also real-time visibility to LV network to manage power flows and service quality in the network.

### Complete Narrative

Information exchange between SCADA and secondary substation PC is realized first. Then PC starts reporting and alarming measurement data collected by use cases LV01+LV02 and MV03 to SCADA.

#### Step Analysis:

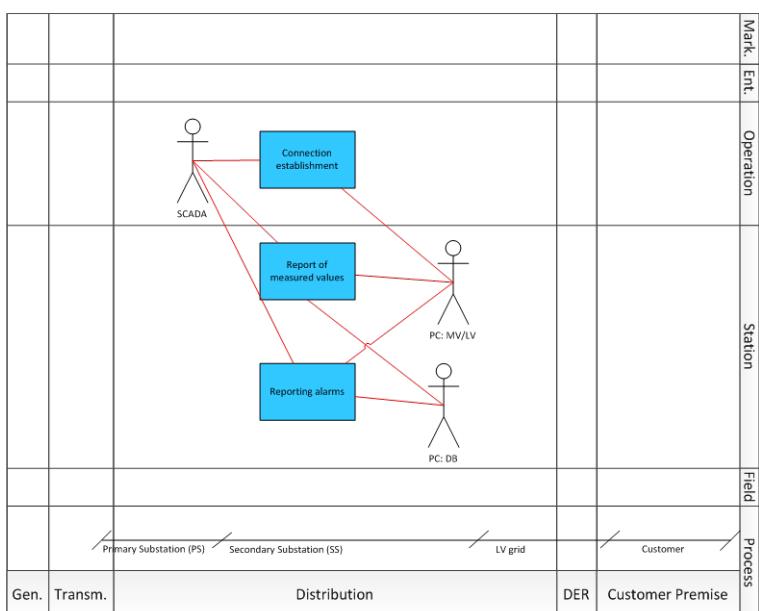
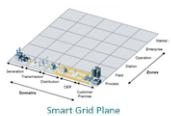
1. SCADA establishes the connection and subscribes for alarms in IEC 61850 to the relevant module in the PC: MV/LV
2. PC: MV/LV exposes measured data as IEC 61850 report data set and send it in a fixed frequency to the SCADA
3. If measured value exceeds alarm limit, the PC: MV/LV that handles the alarms sends the reports to the SCADA
4. Measurements are reviewed every day at PC: MV/LV, compared to threshold levels EN 50160, and a report is created of each monitored measurement value
5. SCADA will receive average values in IEC 61850

#### Actors:

Short Name	Description
PC: DB	Database (in secondary substation PC)
SCADA	SCADA
PC: MV/LV	Reporting tool (in secondary substation PC)

#### Functions:

Short Name	Description
Connection establishment	SCADA establishes the connection and subscribes for alarms in IEC 61850
Report of measured values	IEC 61850 report data set is exposed from measured data (buffered)
Reporting alarms	Unbuffered report is generated



**Figure A7.3: Smart Grid Plane diagram of INTEGRIS – LV01+LV02+MV03 (reporting MV/LV substation and LV measures to SCADA) UC.**

## LV04 Manage power flows and voltage

### Short description

The purpose of this use case is to manage power flows and voltage level in LV network by controlling domestic consumption and PV generation by means of smart meters (SMs), power quality meters (PQMs), and HGW.

### Scope

The purpose of this use case is to manage power flows and voltage level in LV network by controlling domestic consumption and PV generation.

### Objectives

The goals are: to maintain the power in the network within the limits.

### Business Objective

Enhancing efficiency in day-to-day operation.

### Complete Narrative

After collecting the measurements from the RTU Data Collector and Meter Data Collector (MDC), they will be stored in a dedicated Data Base (DB).

### Step Analysis:

1. Main program of PC (consists of PC: UDC and PC: RTUDC) starts up Octave which includes functions PC: SE and PC: MPFV

2. PC: SE reads latest synchronized RTU, DM and SM measurements from PC: DB
3. PC:SE calculates states estimation for each phase low voltage feeders and secondary transformer based on static network data and real-time measurements
4. PC: MPFV checks if power network limitations are exceeded. Power network limitations are fixed in the laboratory scenario.
5. PC: MPFV decides where and how much distributed energy resources are controlled to manage power flow network limitations
6. PC: MPFV writes control commands to PC: DB
7. PC: UDC reads control commands from PC: DB and sends them to the MDC using SOAP interface. MDC translates it to DLMS and sends it to the SM, which in turns sends it to the HGW using a proprietary HTTP protocol.
8. HGW sends back acknowledge to the SM confirming the correct reception of the commands, which in turns sends an acknowledge to the MDC
9. HGW: AC (alternator controller algorithm in the HGW) decides what distributed energy resources are controlled and possibly how much they are controlled.
10. Based on decisions following options for control are available:
  - HGW disconnects loads using a power switch
  - HGW sends a command to thermostat to adjust temperature setpoint
  - HGW sends a command to inverter via CAN field bus to adjust power output/demand

Actors:

Short Name	Description
PC: SE	State Estimation Algorithm (in the PC)
PC:DB	Data Base (in the PC)
PC: MPFV	Manage Power Flows and Voltage Algorithm (in the PC)
PC: UDC	User Data Collector (in the PC)
MDC	Meter Data Concentrator
SM	Smart Meter
HGW	Home Gateway
DER	Distributed Energy Resource

Functions:

Short Name	Description
Data Acquisition for SE	Data coming from RT Monitoring UC are loaded for SE
SE Algorithm	The SE algorithm per se
MPFV Algorithm	The MPFV algorithm per se

Substation Command Transfer	Commands generated by the MPFV algorithm are stored into the PC: DB and then transferred to the MDC
Command/Acknowledge Transfer	Commands and acknowledges are sent to the process actors
DER Control	The algorithm which decides among: load disconnection, temperature setpoint, and PV inverter power setpoint

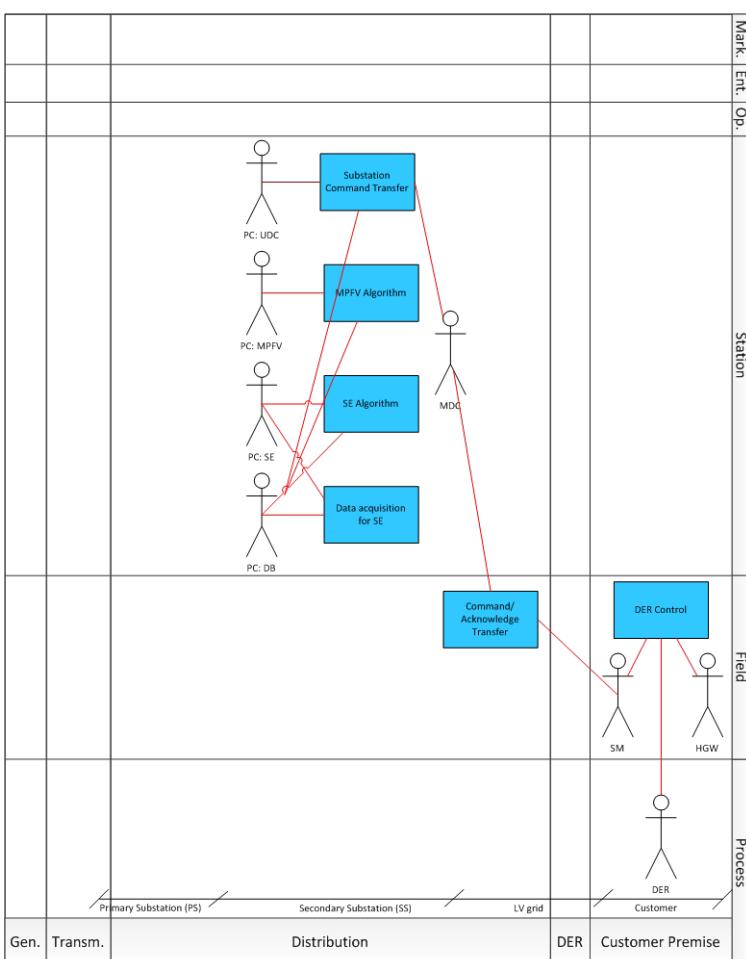
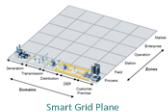


Figure A7.4: Smart Grid Plane diagram of INTEGRIS – LV04 Manage power flows and voltage UC.

## LV05 Manage fault

### Short description

The use case describes fault management process for fault detected in the LV network.

### Scope

The fault management includes the fault isolation, generation deactivation and report generation process for a complete report of fault data and affected area for every fault detected.

## Objectives

Isolation of the fault, fault monitored data gathering, fault area definition and fault report generation.

## Business Objective

Reduce the economic impact of the fault by reducing the affected area and producing relevant information for service restoration.

## Complete Narrative

This use case describes how could the system use fault alarms reported by smart meters to generate fault area reports.

Meters will report information on line faults and even zero conductor faults in case they are three phase meters. All this information will be sent to PQ. If a fault is detected, PQ will report to Main switch, and then it will send fault data to HGW which is in charge of generating units disconnection.

After this first reaction, HGW will publish fault data information, where UDC will be able to gather it to store it in a database, generate the alarms to be used by the FM during the fault area definition and alarms to be reported to SCADA system.

Step Analysis:

1. PQM detects a fault and commands local switch
2. PQM sends fault data to HGW
3. HGW commands disconnection of generating units if needed.
4. HGW publishes fault data
5. PC: UDC collects fault data
6. PC: UDC sends collected fault data to PC: DB storage
7. PC: UDC generates relevant alarms and health status
8. PC: FM sends defined faulty area information to PC: UDC
9. PC: UDC generates IEC61850 alarms and reports to SCADA

Actors:

Short Name	Description
DG	Distributed Generator
HGW	Home Gateway (ThereGate)
PQM	Power Quality Meter
Switch	Switch
SCADA	Supervisory Control And Data Acquisition
PC:FM	Fault Manager (in the PC)

PC:DB	Data Base (in the PC)
PC:UDC	User Data Collector (in the PC)

Functions:

Short Name	Description
<b>Data of the fault</b>	Detected fault information storage. To be used for further processing
<b>Info of faulty area</b>	Produces faulty area definition
<b>Fault monitoring</b>	Check network power quality events and current generation information to detect faults
<b>Switch control</b>	Switch operation interface
<b>DG control</b>	DG operation interface
<b>Reasons for fault</b>	Produces network possible fault reasons

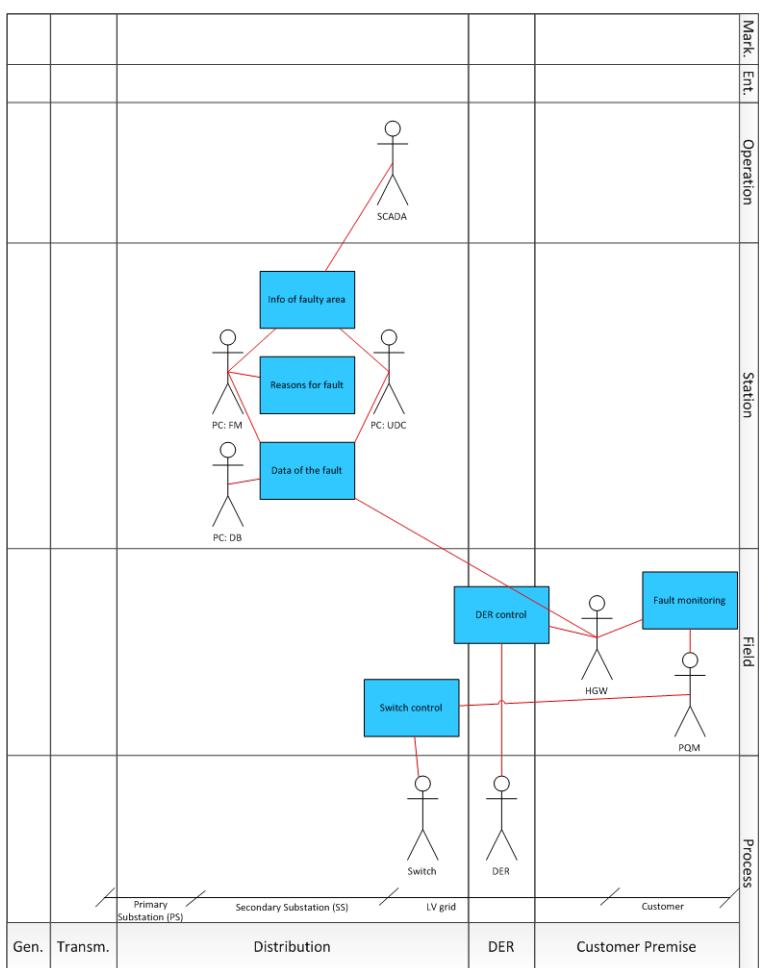
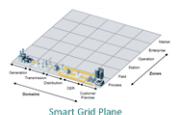


Figure A7.5: Smart Grid Plane diagram of INTEGRIS – LV04 Manage power flows and voltage UC.

## Annex 8 – ADDRESS Use Cases

### Configure load areas

#### Short description

This use case shows the interaction between the TSO and the DSO, and between the DSO and the aggregator, required to assign the macro load areas/load areas/prosumers properly.

#### Scope

The purpose of this use case is the creation of the load areas based on technical parameters relevant to the DSO.

#### Objectives

The configuration of load areas aims at building a structure of the network where active demand products can be activated.

#### Business Objective

The configuration of load areas aims at building a structure of the network where active demand products can be bought/sold.

#### Complete Narrative

Assumption: DSO has the knowledge of which low voltage consumer is in the portfolio of each aggregator; this is done off-line and not be part of this specification.

#### Step Analysis:

1. TSO assigns each (DSO's) load area to a macro load area and communicates this information to the DSO.
2. DSO assigns each consumer to a load area and communicates this information to the aggregator.
3. If the TSO changes the assignment of load areas, then it informs the DSO, that will perform the change in the load configuration, and then the DSO will inform the aggregator.

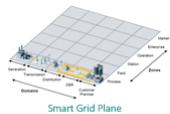
#### Actors:

Short Name	Description
Aggregator	Mediators between the consumers on one side and the markets and the other power system participants on the other side
Consumer	A residential consumer of electricity that may also be involved in contract-based Demand/Response.
DSO	Distribution System Operator
TSO	Transmission System Operator

#### Functions:

Short Name	Description
------------	-------------

<b>Macro load area configuration</b>	Creation or updating the macro load areas
<b>Assignment each consumer to a load area</b>	Consumers are assigned to established load areas



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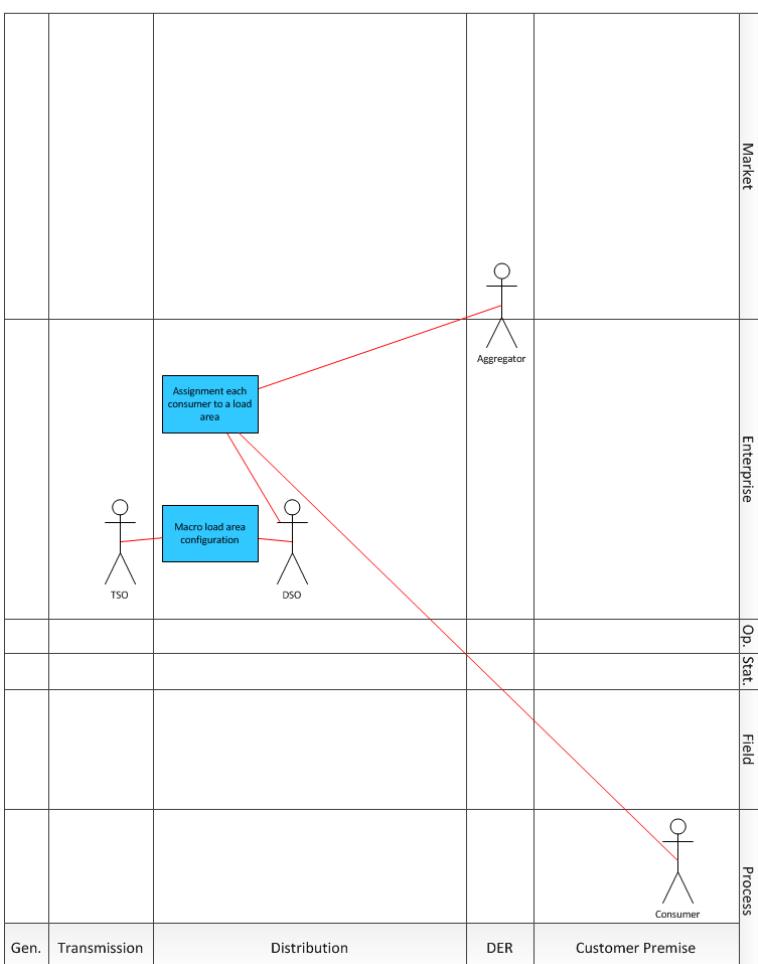


Figure A8.1: Smart Grid Plane diagram of ADDRESS – Configure load areas UC.

## Exchange flexibility tables

### Short description

This use case shows the interaction between the TSO and the DSO, and between the DSO and the aggregator, required to exchange the flexibility tables before participating in active demand markets.

### Scope

The purpose of this use case is to provide the aggregator with a flexibility table for planning its bids before going to the market.

### Objectives

Defining the flexibility amount for each macro load area.

### **Business Objective**

Prepare the aggregator with the right bid when it goes to the market.

### **Complete Narrative**

Step Analysis:

1. The TSO makes internal calculation of flexibility tables for macro load areas and informs the DSO before each bidding process, to indicate the scope within the aggregator can bid for.
2. The DSO makes its internal calculation of flexibility tables for load areas as well and then informs the aggregator before each bidding process, to indicate the scope within which the Aggregators can bid for.

Actors:

Short Name	Description
<b>Aggregator</b>	Mediators between the consumers on one side and the markets and the other power system participants on the other side
<b>DSO</b>	Distribution System Operator
<b>TSO</b>	Transmission System Operator

Functions:

Short Name	Description
<b>Flexibility table calculation (TSO perspective)</b>	Creation or updating flexibility table by the TSO
<b>Flexibility table calculation (DSO perspective)</b>	Creation or updating flexibility table by the DSO

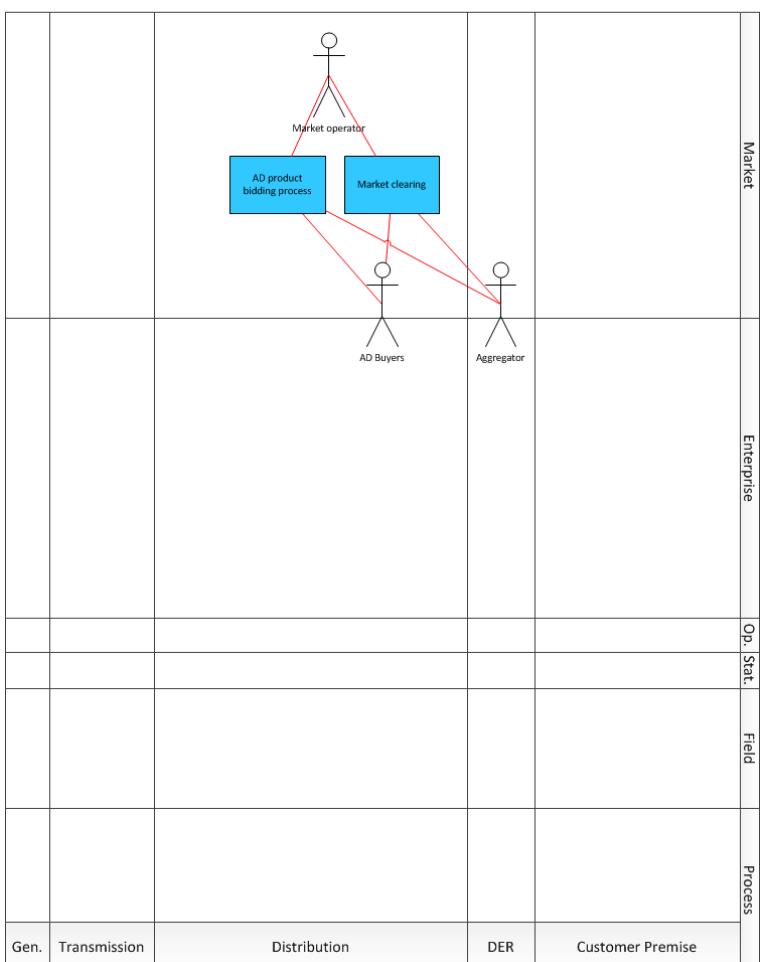
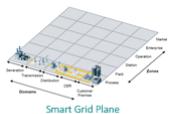


Figure A8.2: Smart Grid Plane diagram of ADDRESS – Exchange flexibility tables UC.

## Clear AD market

### Short description

This use case shows the interaction between the active demand buyers and suppliers with the market operator in order to enable market clearing for any AD product.

### Scope

The purpose of this use case is the establishment of transaction among market operator, aggregator, and AD buyers for the market of AD products.

### Objectives

Establishment of set of accepted offers for AD products.

### Business Objective

Establishment of set of accepted offers for AD products with market clearing price.

### Complete Narrative

## Step Analysis:

1. The market operator creates and publishes a bidding process for the active demand product before the gate opens for the day-ahead or intra-day market (SRP) or in the CRP scenario.
2. The active demand buyers and the aggregator create and submit their AD bids. One message is sent for each load area for which the service is needed.
3. The market clears itself to work out the set of accepted bids and the market clearing price and publishes the market clearing price to inform the AD buyers and the aggregator.

## Actors:

Short Name	Description
<b>Aggregator</b>	Mediators between the consumers on one side and the markets and the other power system participants on the other side
<b>AD Buyers</b>	Entities or utility operators interested in buying active demand products
<b>Market Operator</b>	Determines the market energy price for the market balance area after applying technical constraints from the system operator. The market operator matches all the bids in the market and decides the power traded by the aggregator in each period of the next day. This information is sent to the aggregator and to the TSO and DSO.

## Functions:

Short Name	Description
<b>AD product bidding process</b>	Mechanism which regulates the offer/bid process
<b>Market clearing</b>	Phase in which the set of accepted offers is published along with the market clearing price

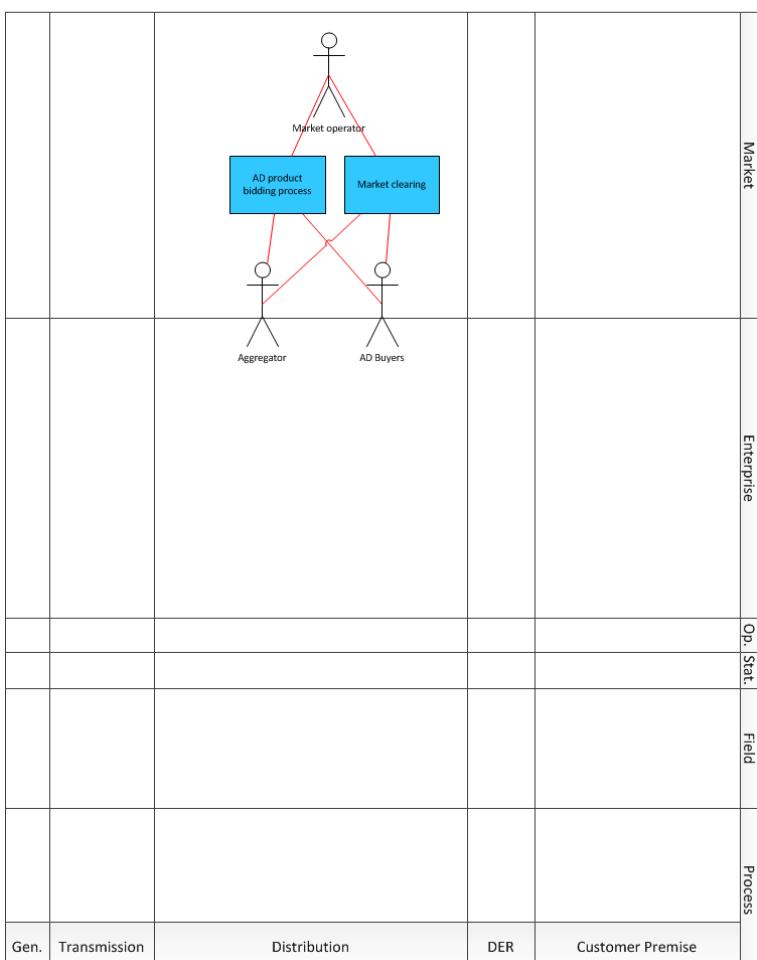
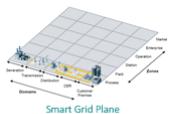


Figure A8.3: Smart Grid Plane diagram of ADDRESS – Clear AD market UC.

## Validate technical feasibility

### Short description

This use case shows the interaction between the aggregator and the DSO, and the DSO and the TSO, required to validate the technical feasibility of the bids resulting from the market clearing process.

### Scope

The purpose of this use case is the validation of the elected AD schedule once the market has been cleared.

### Objectives

To validate the technical feasibility of the elected AD schedule of consumer aggregated by each load area (DSO's point of view) and the same schedule for each macro load area (TSO's point of view).

### Business Objective

This use case is complementary of the previous one. Therefore, its business objective is the same.

### Complete Narrative

No price information is sent, only technical information.

Step Analysis:

1. When the market is cleared, the aggregator sends the DSO the AD schedule of consumers aggregated for each load area for its technical evaluation feasibility.
2. The DSO performs the technical validation of all cleared bids and sends the TSO the AD schedule of consumers for each macro load area for its technical evaluation feasibility.
3. The TSO performs the technical validation of all cleared bids and informs the DSO which eventually informs the aggregator about eventual load area modifications due to the technical validation.

Actors:

Short Name	Description
Aggregator	Mediators between the consumers on one side and the markets and the other power system participants on the other side
DSO	Distribution System Operator
TSO	Transmission System Operator

Functions:

Short Name	Description
Technical validation reporting	Technical feasibility report exchanged among aggregator, DOS, and TSO
AD schedule reporting	AD schedule report exchanged among aggregator, DOS, and TSO
Technical feasibility evaluation	This check is done both at DSO level and the TSO level

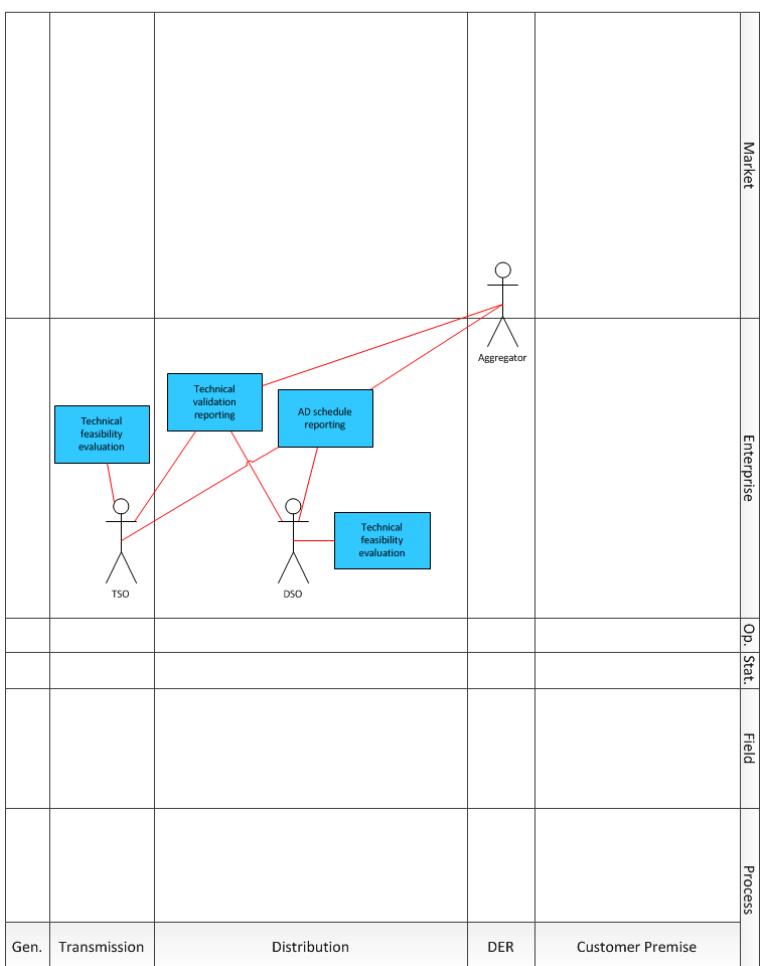
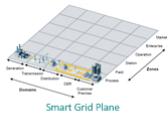


Figure A8.4: Smart Grid Plane diagram of ADDRESS – Validate technical feasibility UC.

## Activate AD product

### Short description

This use case shows the interaction between the active demand buyer and the aggregator, required to activate the CRP active demand product.

### Scope

The purpose of this use case is to inform the aggregator in case of the need of the activation of a CRP product.

### Objectives

The goal is to activate the CRP product.

### Business Objective

The business goal is to activate the CRP product previously bought.

### Complete Narrative

## Step Analysis:

1. In case of a CRP product, active demand buyer needs to send an explicit signal to the aggregator, telling that the CRP product needs to be activated.

## Actors:

Short Name	Description
<b>Aggregator</b>	Mediators between the consumers on one side and the markets and the other power system participants on the other side
<b>AD Buyers</b>	Entities or utility operators interested in buying active demand products

## Functions:

Short Name	Description
<b>CRP AD product activation</b>	CRP AD product activation request

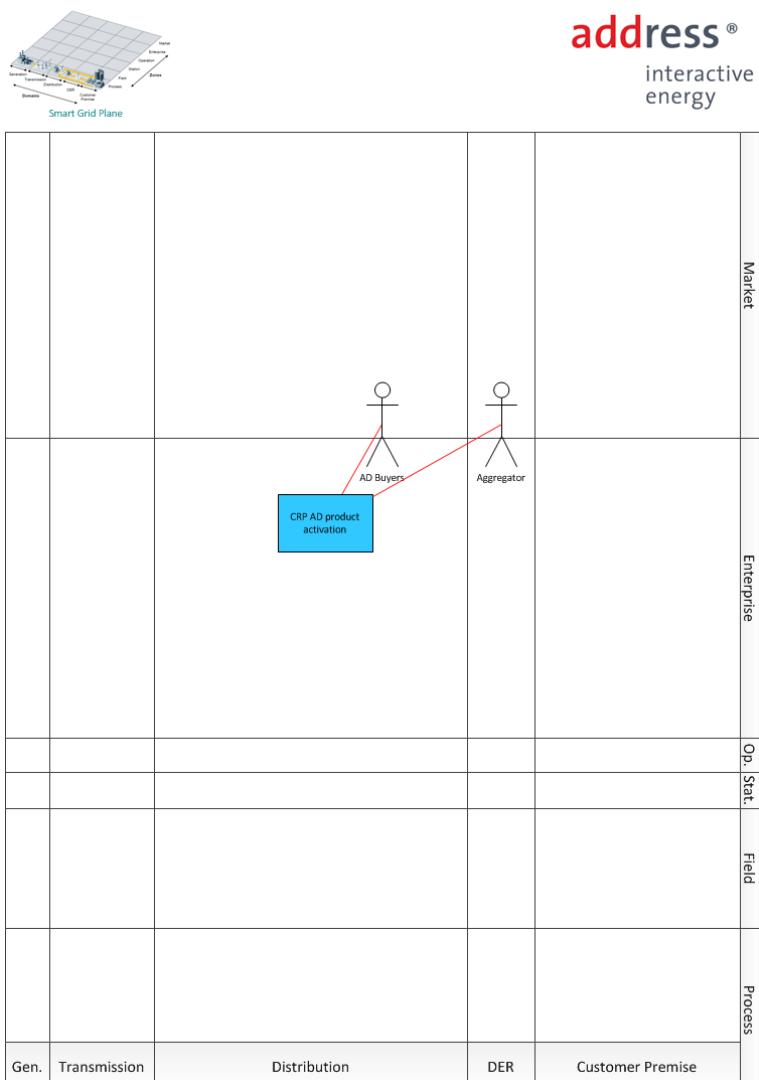


Figure A8.5: Smart Grid Plane diagram of ADDRESS – Activate AD product UC.

## Annex 9 – Communication standards

The introduction of narrowband PLC protocols like PRIME [27] and G3-PLC [28] gave a first improvement in communications. PRIME, whose referring model is showed in Figure A9.2, has been tested in many European countries (Spain, France, Switzerland) and is already used in Spain on the IBERDROLA Network. PRIME has been moreover evaluated and adopted in the FP7 Open Meter Project [29] as the data exchange protocol for the digital meters.

PRIME main features consist in the use of an OFDM modulation with 97 subcarriers in the 42-89 kHz band range, allowing it to reach a hypothetical performance of 128 kbit/s. Moreover, the OFDM modulation provides a high spectral efficiency and increases the system noise resistance.

PRIME specification describes physical, link, convergence layer for adapting several specific services such us DLMS/COSEM and a management plane, as showed in Figure A9.1.

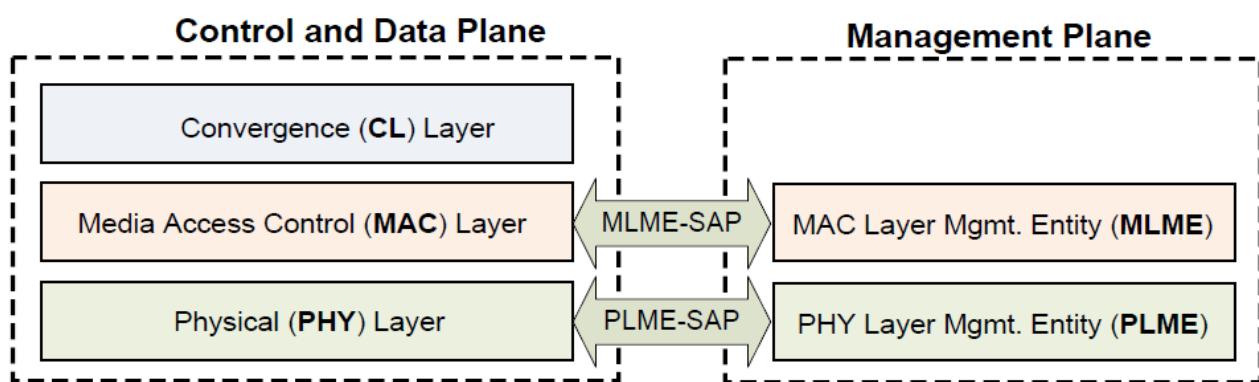


Figure A9.1: Reference model of protocol layers used in the OFDM PRIME specification.

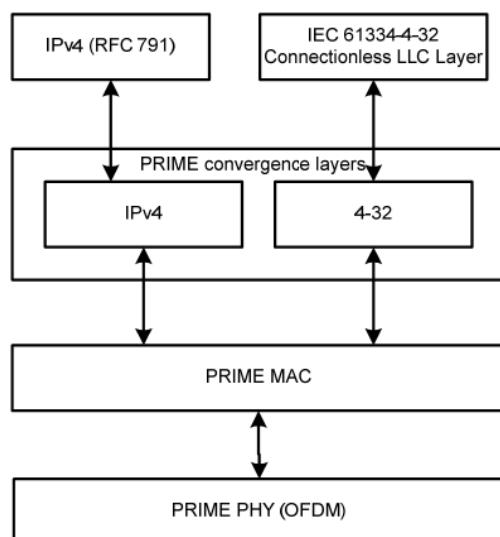


Figure A9.2: PRIME Model.

PRIME networks are composed by one base node and many remote nodes. Each remote node can act as a repeater called “switch” for the traffic send/received to/from other remote nodes. A node which is not switching traffic from other nodes is called “terminal”. Even in the case of mesh networks, the base node will use link quality information reported from the nodes in its subnetwork to determine link layer topology by controlling the nodes states according to the following service node state flow.

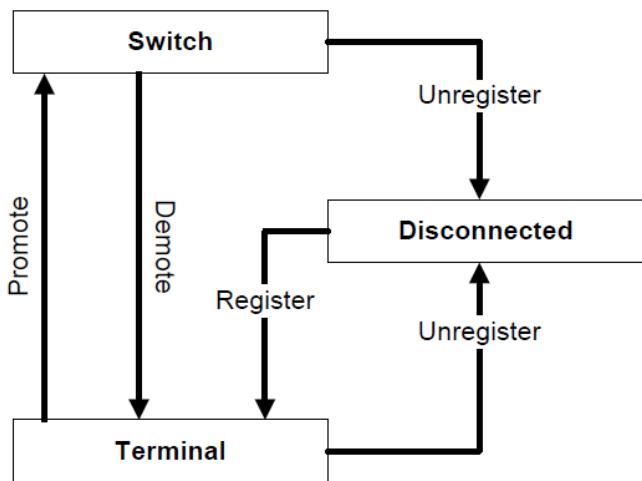


Figure A9.3: Service node states.

PRIME MAC level supports both *contention-free* (i.e. the TDM described with the BPL) and *contention-based* access policies like Carrier Sense Multiple Access with Collision Avoidance (CSMA/CA).

CSMA literally means that, in multiple node networks where each node can simultaneously communicate (Multiple Access) through a common channel, each device must check if the other nodes are already communicating, before it can start its data transmission (Carrier Sense). Only if the channel is free the node can start the communication, otherwise it will have to wait for an arbitrary interval before making another attempt.

Nevertheless, these transmission delays can cause packet collisions: that's the reason why in wired networks (like Ethernet IEEE 802.3) a protocol variant called CSMA with Collision Detection (CD) is used; in this protocol, the device listens to the channel also during the transmission, in order to discover promptly the collisions and re-transmit immediately the lost packet.

In the Wireless or PLC networks it is not ensured that each node can communicate with all the others, so the collision detection cannot also be granted. In those cases, the CSMA with Collision Avoidance (CA) is used: with this technique the sender transmits a short message to the receiver, which broadcasts at once a message to all the nodes (including the sender), informing that the channel will be reserved for a determined period.

Compared to *contention-free* protocols like TDM, which is capable to grant the absence of collisions, the CSMA results much simpler because it is not necessary to implement any synchronization mechanism between the devices.