DISTRIBUTED AUTOMATION SOLUTION AND VOLTAGE CONTROL IN MV AND LV DISTRIBUTION NETWORKS

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ABSTRACT

Distributed generation and consequent voltage rise problem in MV distribution networks has been found to have similar effects in LV networks due to the worldwide growth of small-scale PV generation. Multiple strategies have been proposed to mitigate the voltage rise issues in order to increase hosting capacity of distributed generation in distribution networks. New solutions have to be found to better utilize available resources and information in active network management. This paper studies the operation of coordinated voltage control in MV and LV grids, and presents a proof-of-concept implementation of distributed automation architecture for coordinated voltage control in both networks in Real Time Digital Simulator environment.

INTRODUCTION

Increasing amount of Distributed Energy Resources (DERs) are being connected to the distribution voltage levels, on both medium voltage and low voltage distribution networks. The connection of Distributed Generation (DG) and other DERs alter traditional assumptions in the network operation, and pose challenges to Distribution System Operators (DSOs) as such. Voltage rise at DG connection point is the foremost problem when planning the interconnection and considering the desired operational limits in future.

The voltage rise can be mitigated by using strategies such as

1) Increasing conductor size to reduce feeder impedance
2) Using On-Load Tap Changer (OLTC) to reduce substation and downstream voltages at HV/MV or MV/LV substations
3) Utilizing the reactive power capability of DERs, or production curtailment in extreme cases
4) Utilizing newer technologies such as energy storages or demand side management.

Usually the voltage rise effect has been prominent at MV level. The exponential worldwide growth of small-scale PV generation has introduced similar problems on LV feeders with high aggregated installed capacity or long distances from distribution transformer. Different resistance/reactance(R/X) ratio in these networks influences the effectiveness of the mitigation methods. Previous studies on voltage control have shown the effectiveness of coordinated voltage control in voltage rise mitigation and increasing hosting capacity when compared to local voltage control strategies in MV [1] and LV networks [2]. Centralized coordinated control performs the operations for entire network from Distribution Management System (DMS), whereas decentralized local control is carried out locally according to local measurements. DMS centralized coordinated voltage control has been simulated in [3]. Adding LV level to the control scheme, DMS coordinated distributed voltage control of LV networks has been simulated in [4].

Coordinated voltage control requires extensive information of the network's current state. Often the proposed applications have not been demonstrated in real-time, which excludes the consideration of complex communication infrastructure and data transfer. With the increasing amount of real-time measurements from the network available, the burden that possible data transfer from all around the network to control center and DMS would cause heavily suggests decentralizing the monitoring and control to lower levels of automation. Thus, basing the architecture on hierarchical structure the scalability requirement can be fulfilled. Automation units at primary and secondary substations could handle the information gathering and deciding of control actions in the network they are responsible for. However, the fact that operation of voltage control resources, e.g. HV/MV OLTC, have effect on voltages across voltage levels cannot be ignored. Therefore, coordination among the proposed decentralized controllers is required.

In this paper the hierarchical automation and voltage control architecture is first described and then put in to practice in Real Time Digital Simulator (RTDS) environment. Real-time simulations of a real distribution network are used as case study to validate operation of coordinated voltage control of MV and LV networks in real-time operation.

AUTOMATION ARCHITECTURE

The need for new types of automation architectures in distribution networks originates from the fact that large quantity of real-time measurements and controllable resources are available in future distribution networks. Collecting measurement data from vicinity of LV customers directly to control center and centralized management system like DMS stresses the communication system heavily and the communication is prone to single point of failure problems. In order to more efficiently exploit all the possible information in the network to run state estimation and to optimize the operation of distribution network, decision making and information gathering at lower levels of automation is suggested. To achieve this, hierarchy different from the typical centralized architecture, where everything is concentrated at the control center and DMS, needs to be defined. Fig. 1 depicts a proposal of distributed automation and control architecture in MV and all connected LV networks. Following sections describe further all the actors seen in the figure.

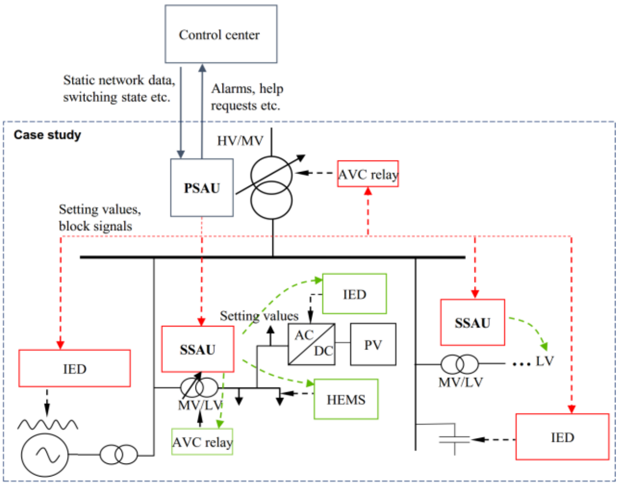

***Fig. 1** Distributed automation and control architecture*

Control hierarchy

The control hierarchy in future distribution networks can be divided to three hierarchical levels: primary, secondary and tertiary control. Each hierarchical level operates in different time-frame and grid level, and for coordination purposes only priority information is sent between the secondary controllers or to the tertiary control level.

Primary controllers are the Intelligent Electronic Devices (IEDs) which control either DSO's own resources like OLTCs (controlled by Automatic Voltage Controller (AVC) relays) at substations and reactive power compensation, or customer owned DERs where the control type can be either contracted or emergency type. This type of control can be based on local measurements to make autonomous control decisions within order of seconds.

Secondary controller (Substation Automation Unit, SAU) is the new key element in the architecture [5]. The SAUs perform monitoring and control actions at primary and secondary substation level by first storing information of the network status, running state estimation and voltage control algorithms to calculate optimal network state, and finally by sending new set points to primary controllers of controllable DERs in the network. The SAUs coordinate the operation of the primary controllers (IEDs of the DERs) and lower level SAUs in the automation architecture.

Highest level of the hierarchy is tertiary control at the control center. The time-frame of operations varies from tens of minutes to hours. Network reconfiguration and market related services are handled by the tertiary controller. The focus of the paper is on secondary control.

Substation Automation Unit

An automation unit (the SAU) located at primary substation monitors and controls resources in MV network similarly to SAUs at secondary substations. SAU consists of network algorithms, interfaces to field devices and database. The SAU and its database are developed in a standard-based manner which makes the implementation interoperable with any vendor's new generation substation automation IEDs.

Algorithms

Developed SAU algorithms are independent in a way that all input data to an algorithm is read from the database, and all algorithm output data is written to the database to be read by other algorithms. SAU algorithms needed in realizing coordinated voltage control are load and production forecaster, state estimation and voltage control algorithms. Information of near future and prevailing network state are mandatory inputs for voltage control algorithm to correctly optimize the network state. Similar algorithms can be used on each network level with minor voltage level specific modifications.

Communication interfaces

For communication with primary controllers and other SAUs, the SAU requires communication interfaces. IEC 61850 MMS is used in communication with IEDs and for communication with upper level control. The newest standard in the field of smart metering, DLMS/COSEM, is used to communicate with smart meters.

Database

Data stored in the SAU database is mainly related to grid portion in question: static network topology and parameters, and dynamic measurement and command data from the physical devices from the field. State estimates calculated by the algorithm are stored similarly to the real-time measurements. The database schemas are created according to IEC61850 data model and Common Information Model (CIM) in the database to store static network information at the SAU. Dedicated schemas in the database represent these two categories. Further, a link between the two schemas is done with bridge schema which locates a measurement or control command in the network topology. Management schema stores algorithm execution related logs and information for debugging purposes. The SAU database is implemented using PostgreSQL.

COORDINATED VOLTAGE CONTROL IMPLEMENTATION

The coordinated voltage control implemented in both MV and LV grids in this paper is based on [6]. Weighted least squares based State Estimation is used to provide necessary inputs, which include phase voltages of each network node, branch currents, and real and reactive powers of each load and production node. Full network topology information is available in the SAU database.

The algorithm can utilize multiple types of controllable resources which have primary controller and interface to the SAU database implemented. Real and reactive power of DG units, reactive power set point of reactive power compensation, controllable loads and voltage reference set points to AVC relays of OLTCs are resources that can be currently utilized. The algorithm aims to minimize objective function in Eq. 1, where C_{losses} is the cost for network losses P_{losses}, C_{cur} is the cost for generation curtailment $\sum P_{cur}$, C_{tap} is the cost for tap changer operations n_{tap}, C_{DR} is the cost for load control $\sum P_{DR}$, and C_{Vdiff} is the cost for voltage deviation from nominal on all nodes, $\sum(V_{i,r}-V_i)^2$. Network constraints and load flow equations are taken into account in the optimization. The problem is a mixed-integer non-linear programming problem which is solved by sequential quadratic programming in Octave.

$$f = C_{losses}P_{losses} + C_{cur}\sum P_{cur} + C_{tap}n_{tap} + C_{DR}\sum P_{DR} + C_{Vdiff}\sum (V_{i,r}-V_i)^2 \qquad (1)$$

Real-time sequence

In real-time sequence, the algorithms are executed once a minute. State estimation is run first, followed by voltage control algorithm. In order to avoid oscillation between the simultaneous real-time control of MV and LV networks, some sort of coordination is required among the secondary controllers. This can be either implemented using blocking signals or using graded time delays of AVC relay control loops of OLTCs. When using blocking signals, the reason for voltage variations needs first to be originated. For instance, with a blocking signal from upper level SAU to lower level SAU the operation of OLTC and voltage control algorithm can be delayed until upper level algorithm has finished its control actions, and thus unnecessary control actions can be avoided.

In preparation studies graded time delays alone proved to avoid unnecessary OLTC actions but clashing voltage reference set points were found to be set simultaneously on MV and LV levels which needed to be reverted later on. To prevent this from happening, the execution of algorithms is staggered within the one-minute timeframe. The real time sequence of algorithm execution is depicted in Fig. 2.

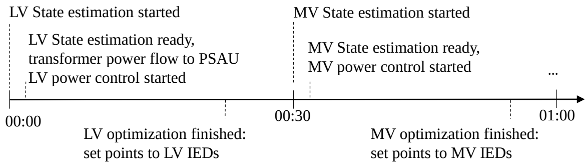

Fig. 2 *Real time sequence of algorithms in coordinated voltage control. With long execution times, control actions within same minute may not be visible to other voltage level in this alternative implementation.*

CASE STUDY

The simulation environment for the case study is depicted in Fig. 3. It consists of two SAUs, both running on same Linux computer due to the same physical location in laboratory environment. The SAU hardware is a typical PC hardware with an SSD hard-drive. With RTDS all calculations are performed in real-time which enables connection of commercial monitoring and control IEDs to the simulation environment. AVC relay at secondary substation, and two smart meters measuring two critical load nodes in LV network, are connected to the simulator. A dedicated Windows computer runs RSCAD, a software where the complete network model is built. Additionally, an instance of MATLAB is used to provide a two-way communication between the databases and algorithms regarding measurements and set points of modeled AVC relay and PV units.

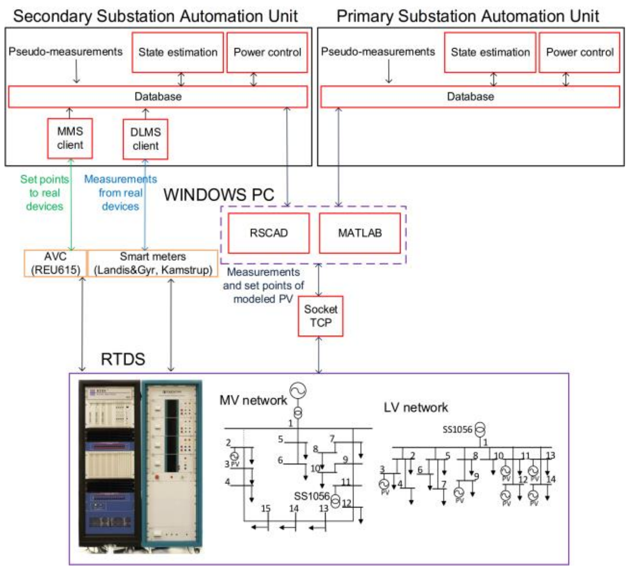

Fig. 3 *RTDS laboratory environment*

Simulation network model

The simulation network model in RSCAD represents a real MV and LV distribution network. The model consists of primary substation and one secondary substation. Other secondary substations are modeled as constant PQ buses. The number of nodes have been reduced due to limitations in the RTDS. Controllable resources in the network include HV/MV tap changer at primary substation and MV/LV tap changer at secondary substation, each controlled by AVC relay, and 6 controllable PV units in LV network and 1 DG in MV network. Static constant power loads represent customers in all LV network nodes and in some MV network nodes.

Simulation scenarios

RTDS allows creation of artificial scenarios from which the operation of proposed coordinated voltage control arrangement can be observed. Table 1 and Fig. 4 describe two scenarios used in this case study. Violations of voltage limits are created in the scenarios, and thus interactions of the controllers across voltage levels are observed. In the first scenario feeding network voltage is altered. It is noteworthy that the primary substation in the network is actually a 23/15 kV intermediate substation.

***Table 1** Scenario 1 – Feeding network voltage*

Time	Primary substation feeding voltage (kV)
0:00	23.0
1:45	23.5
3:45	23.0
5:15	23.3
7:00	end

In the second scenario, the output of all PV units is varied according to real data of PV output throughout a 24-hour scenario depicted in Fig. 4. The nominal powers of the real network's PV units have been multiplied by factor of 3 in order to create congestions in the network.

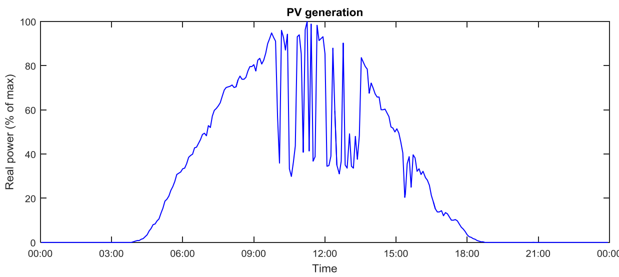

***Fig. 4** Scenario 2 - Typical daily PV generation curve*

Results

Following presents results for the two chosen scenarios. The observations of control actions and interactions of MV and LV power control are embedded within the graphs in Fig. 5. The results of typical daily variation of PV output scenario are depicted in Fig. 6 and explained briefly after. The graphs for each scenario represent MV and LV network node voltages, substation voltages with AVC relay set point, and tap changer position. Red dashed lines present voltage limits of ± 5% from nominal.

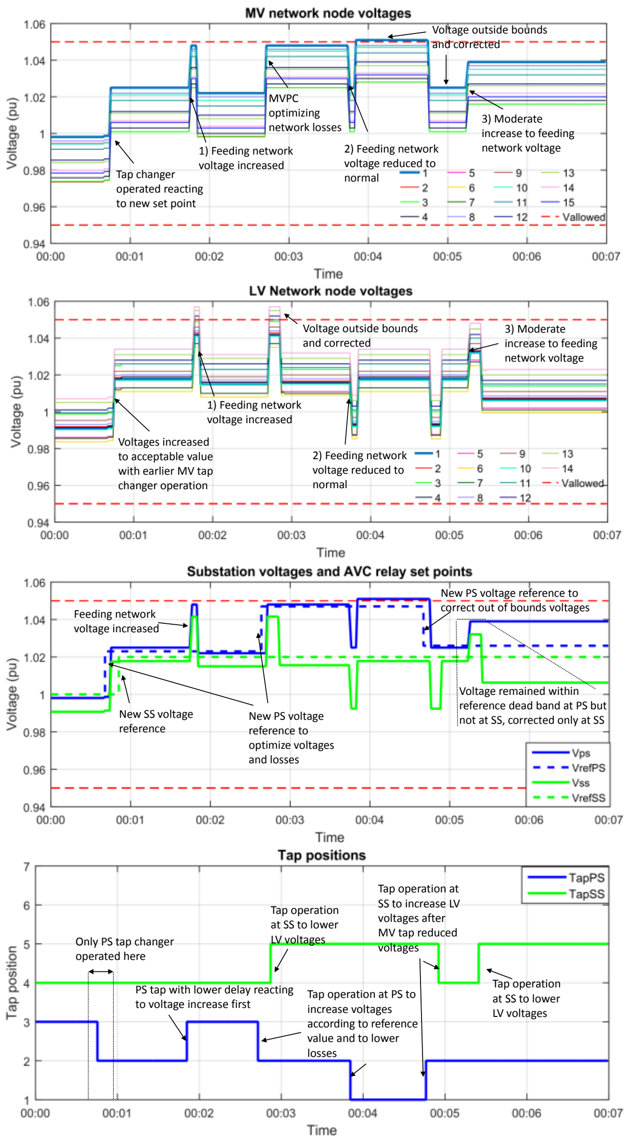

***Fig. 5** Scenario 1 graphs*

From the first scenario, observations of interactions of the secondary controllers across voltage levels can be made. First, the individual networks are optimized accordingly and the networks interact together to achieve optimal network state across voltage levels. The flaws in sequential execution of the MV and LV algorithms are seen during the first minutes in the scenario, when LV algorithms had not finished before running MV algorithms. The algorithm execution times vary with different network sizes, and amount and type of controllable resources. Second, the voltage changes in the scenario are originated to MV level, but which are also seen in the LV network, are correctly handled by control actions at MV level. In general, the control scheme works as intended.

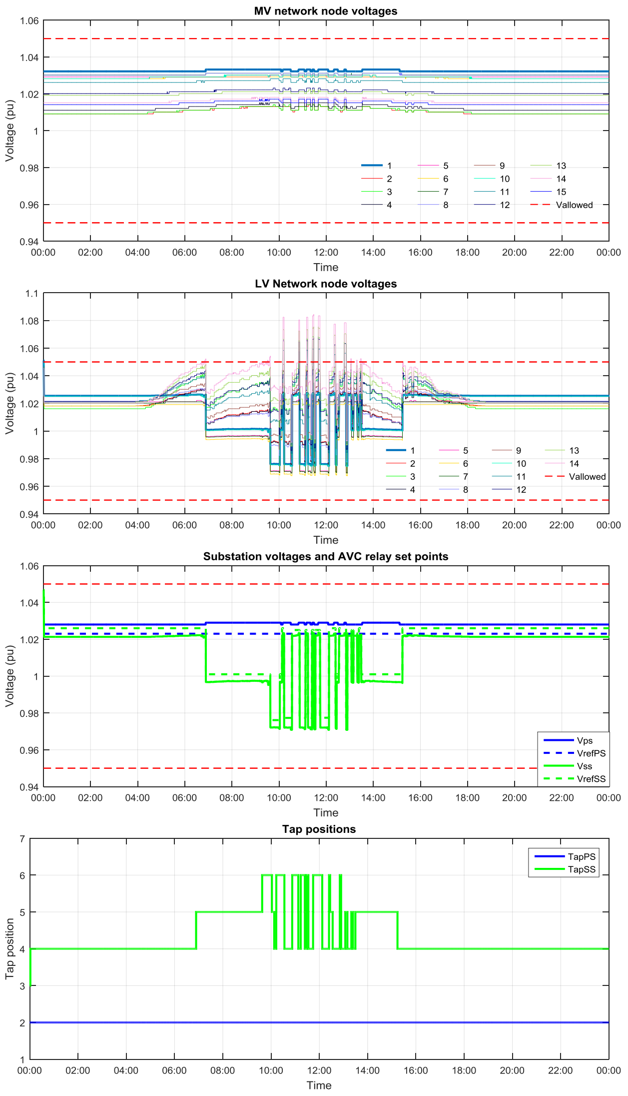

Fig. 6 *Scenario 2 graphs*

From Fig. 6 the conclusion can be drawn that the voltage variations are handled at the LV network portion where the effect of PV output in voltages is mainly seen. With the higher, artificial, penetration of PV varying between 30% and 100% of output, many changes to secondary substation AVC relay voltage reference set point can be observed during mid-day. Therefore, also tap changer actions according to fourth graph in Fig. 6 have been made. The algorithm is by default tuned to have cost for voltage difference from nominal set to 0, and thus to optimize voltages closer to the upper voltage limit. Therefore, with 30% PV output during the middle of the day, and following substantial increase to 100% output, over-voltages are observed. These over-voltages, however, are always corrected after the next algorithm execution by setting new, lower, voltage reference value. This increases number of tap changer operations, and the need for maintenance. By changing the algorithm setting parameters to aim for voltages closer to nominal, usually at the cost of network losses, the over-voltages in the scenarios could be avoided.

CONCLUSION

This paper presents automation concept for future distribution networks where distributed energy resources bring flexibility for active network management and thus can be utilized to optimize distribution network operation. By decentralizing automation at lower levels comprehensive monitoring and control of the whole distribution network can be achieved. The case study performed in the paper confirms the operation of application of the approach in real-time environment with integrated monitoring and control IEDs.

Further benefit of the solution is that it is developed in a standard-based manner. Thus, the final implementation is possible with any vendor's new generation distribution automation devices.

Acknowledgments

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IEC 61850-based Communication and Aggregation Solution for Demand-Response Application

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***Abstract*—This paper presents an IEC 61850 standard-based communication and aggregation solution for Demand-Response application, which allows end devices automatically detected, configured and integrated to the overlying Demand-Response system, thereby greatly increasing the integration efficiency, and making large scale of deployment feasible. This communication solution is dedicated to one community-wide Demand-Response application designed for a residential area near an industrial installation in Sweden. The community-wide Demand-Response application will be briefly explained in the paper, however, the main focus of this paper is the communication solution and IT system implementation for this application. The communication solution is realized by the unconventional use of IEC 61850 standard, and implemented in a hierarchical structure consisting of SCADA, communication gateway and low cost micro processor-based spatial heating controllers.**

***Index Terms*—communication, ICT system for Demand-Response, IEC 61850, SCADA**

I. Introduction

Demand-Response(DR) is considered as a cost-effective solution to tackle the volatility and uncertainty issue when operating distribution grid, which nowadays becomes increasingly problematic due to the widespread integration of renewable energy resources [1]. However, to deploy DR applications in large scale, it is necessary to provide cheap and simple solutions for end-customers, and to allow end devices communicate with the rest of the DR system smoothly. To this end, standardized communication interfaces are needed for supporting the interoperability on communication, information and functional levels [2]. Also, configuration, management and aggregation of end devices must be done in an efficient way – preferably a new DR end device should be added seamlessly to overlying DR system through some automatic mechanisms, so that the integration cost can be minimized when integrating a vast number of end devices.

Recently, lot of research has been done to increase the communication and integration efficiency for DR systems. Research projects ADDRESS [3] and SGEM [4] explore using CIM model(IEC 61968/61970) and Web Services/SOA(Service-Oriented Architecture) for DR communications. IEC Technical Committee PC118 proposes using OpenADR 2.0 [5] data model as the standard interface. IEC TC57 WG21 are working on adapting OpenADR into aforementioned CIM model [6]. Although considerable research has been devoted to standardizing the communication interface for DR systems, rather less attention has been paid to improve the efficiency for configuration, management and aggregation of DR end devices.

This paper presents an IEC 61850 standard-based communication and integration solution for DR system, which allows DR end devices automatically detected, configured and integrated to overlying DR system, thus greatly increasing the communication and integration efficiency, making large scale of DR deployment feasible. This solution is dedicated to one community-wide DR application designed for a residential area nearby an industrial installation in Sweden.

The paper focuses on communication solution and IT system implementation for the community-wide DR application. This solution is implemented in a hierarchical architecture – end devices run open standards on low cost hardware (Raspberry Pi micro computer), while aggregation, gateway and operator functions can be efficiently managed through a commercial SCADA and PLC (programmable logic controller) system.

The rest of the paper is organized as follows. Section II gives a short overview of the community-wide DR scheme. Section III presents the communication and integration solution designed for this DR system. Emphasis is on how the automatic configuration, management and aggregation of DR end devices is realized by the unconventional use of IEC 61850. Section IV presents the IT system implementation. Finally, future work and conclusion is drawn in Section V.

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II. Background: A Community-wide Demand-Response System

The communication solution presented in this paper was designed for a community-wide Demand-Response application.

A. Use Case

At a zinc mine in central Sweden, electrical power consumption is frequently limited by the power grid capacity. The mine is connected with a single 20 kV overhead power line, and the neighboring residential area of about 400 households is connected with another parallel power line. In this residential area (and in Sweden in general), electric spatial heating is commonplace with either electric radiators or heat pumps. Currently the mine must several times a month close down part of their process (heating of process water for the iron-ore enrichment plant in two 100 kW electric boilers) due to the low capacity of electricity grid. Strengthening of the electricity grid has been investigated and would cost in excess of one million euros, as well as taking several years to finalize application and building processes.

Electric consumption analysis shows: energy use of both the mine and surrounding community follow a regular daily pattern – the mine is emptied twice daily for scheduled blasts, which results in a power demand reduction, followed by a predictable peak when ventilation is maximized; the surrounding community has a peak consumption in morning and afternoon typical for Scandinavian countries where electricity is extensively used for spatial heating.

Actually the problem manifested in this use case is not unique. It is a typical problem when a residential area is located nearby an industrial installation or distributed energy production with limited electricity transport capacity. For solving this kind of problem, within a joint research and development project, a community-wide DR application has been developed.

B. Concept of the Community-wide DR Scheme

This community-wide DR scheme is illustrated as Figure 1. Each customer participating in the DR scheme has one DR unit installed at home. The DR unit collects locally manipulated electricity prices and then plans and controls room heating for the next 24 hours, based on the electricity price and user comfortability, aiming to heat the house at less expensive hours.

Essentially, the DR system is built on top of a home energy management system [7] that is expanded with local price manipulation. Thus, unlike many other home energy management systems which typically take electricity price directly from day-ahead energy market, this DR unit by contrast takes locally manipulated price signals. The locally manipulated price signals can be illustrated by the following theoretical equation.

$$Price_{local}(h) = Price_{nordpool}(h) + Load(h) * f \quad (1)$$

It means: local price for the next h hour, $Price_{local}(h)$, is the combination of Nord Pool hourly spot price, $Price_{nordpool}(h)$(the day-ahead energy market in Nordic

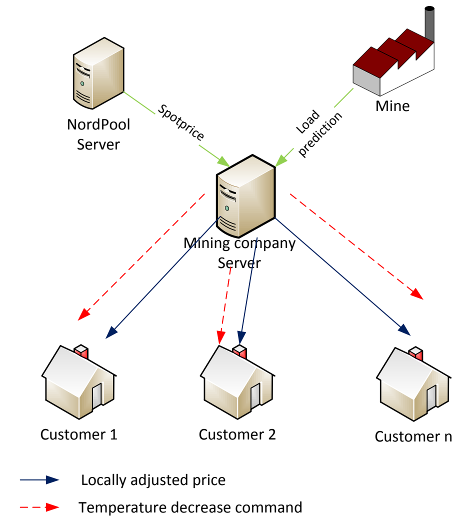

Figure 1. Overview of the Community-wide DR Scheme. (Note: the mining company is not subject to energy market regulation, and this DR scheme can be achieved also without participation of the distribution utility.)

region is operated by Nord Pool [8]), and the price penalty imposed by mining company.

The price penalty transforms mining company's electricity consumption to monetary disincentives. Its calculation is based on the mine's electricity consumption for the next h hour, $Load(h)$, and a scaling factor f. $Load(h)$ can be forecasted by process simulation, which has been implemented in the mining company's SCADA system. Scaling factor f is decided and adjusted according to statistical analysis, and is subject to further research. The actual calculation of price penalty is out of the scope of this paper.

The locally manipulated electricity price ensures that the DR unit will opt to heat houses at non-peak hours in the local grid. Of course, on the other hand, the return for the household use of hourly pricing of electricity will diminish somewhat. But this can be compensated by some settlement agreement between the mining company and customers. As the mine is the communitys largest employer, social acceptance for the community-wide DR scheme is perceived as being particularly favorable.

Participants in the DR scheme are also required to allow the temperature set-point to temporarily drop up to two degrees during situations when the risk of grid congestion would otherwise be imminent. Grid congestion can be predicted with the help of mining company's SCADA system – within a test-bench, measured transfer capacity of the overhead power line (using dynamic line rating) and load estimates from real-time simulation of the mine's processes are presented in the SCADA system. In addition, SCADA operator is also presented with the aggregated load profile for electric heating in the nearby residential area, as well as the combined load reduction capability.

This community-wide DR scheme only concerns residential heating load, because spatial heating constitutes the majority of consumer energy consumption in Scandinavian countries, especially during the winter. Also, demands controlled by the temperature are the most important flexible demands in households [9], which creates a large potential for Demand-Response application.

The focus of this paper is communication solution and ICT system implementation for this community-wide DR system. This will be covered in the remaining part of the paper.

III. IEC 61850-based DR Communication Solution

The implementation of the DR scheme presented in Section II-B relies on extensive information exchanges between DR units and local utility, or in this use case, a local industry that acts as Aggregator.

As indicated in Figure 1, the information flown from Aggregator towards each DR unit includes:

1) locally adjusted price signals for next 24 hours
2) command to decrease customer's room temperature set-point from 0 to 2 degrees

This will ensure that the energy consumption of spatical heating is shifted to the time of low grid congestion and market price. Among these information, price signal is sent once per day, while the temperature decrease command is sent in case of imminent grid congestion, but it could also be sent more frequently. In prototype implementation, this command is sent every 60 seconds in order to monitor the availability of DR units.

Information sent from DR units towards Aggregator includes:

1) temperature measurement for each room
2) electric heating on/off status in each room [1]
3) connected heating load (energy) in each room

These information are sent every 10 to 30 minutes. They are needed for deriving customer load profiles and calculating shiftable loads, and will be anonymized, aggregated and presented in mining company's SCADA screen.

Among all those exchanged information, "locally adjusted price signals" can be easily transmitted by using FTP or HTTP protocol; the rest of information, as will be shortly discussed, can be transmitted by using IEC 61850 power utility automation standards, over a secured VPN connection such as that used by VHPready [10].

A. IEC 61850 standards

IEC 61850 is an information model and communication architecture standard designed to allow interoperability within power utility automation systems. Its major and original application scope is focused at primary substations, and it is now becoming the most common substation communication solution at higher voltage levels in many countries [2]. However, the application of IEC 61850 is not only limited at primary substation automation. Some research initiatives uses this standard at secondary substations [11], [12]. Also at IEC TC57 working groups, extensions for this standard are underway to expand it to various new application domains.

[1]Note: this information is optional. In prototype implementation, this information was not sent.

TABLE I
IEC 61850 data models for the DR Unit (part 1)

Data sent to or from DR Unit	Logical Node class	Data Object	Common Data Class	Data Attribute
temperature measurement	STMP	Tmp	MV	mag
on/off status of the switch for electric heating	XCBR	Pos	DPC	stVal
connected heating load	MMTR	DmdWh	BCR	actVal
set point for minimum indoor temperature	STMP	MinTmp	ASG	setMag[SP]

IEC 61850 uses object-oriented structure for information modeling [13]. In 61850, a power utility automation function is realized by a set of collaborating Logical Nodes distributed over Intelligent Electronic Devices (IEDs), which are typically used for protection, control and monitoring. A Logical Node (LN) is a virtual representation of the communication interface for a primary apparatus, protection and control function or measurement value. It encapsulates multiple Data Objects, which contains numerous attributes including quality, time stamp, etc. Logical Nodes are grouped into Logical Devices that are implemented in IEDs. The standard allows free allocation of functionality to various IEDs [2].

As distribution grids are shifting towards "smarter" grid, IEC 61850 standard also evolves accordingly. Extensions and revisions of this standard are ongoing to cover new application areas at lower voltage level. For instance, IEC 61850-7-420 adds new LNs for the monitoring and control of Distributed Energy Resources (DERs), and its second edition is now available; the upcoming technical report IEC 61850-90-15 will address DER-grid integration, especially the VPP(virtual power plant), DER aggregation and management.

In this paper, IEC 61850 is used by the DR scheme to implement the communication between DR unit and mining company's SCADA system. Using IEC 61850 standard to engineer communication solution typically involves two steps:

Step 1: mapping exchanged information to 61850 data models.
Step 2: mapping communication requirement to 61850 services.

B. Step 1: Mapping to IEC 61850 Data Models

The data modeling for DR unit utilizes Logical Nodes from IEC 61850-7-4, edition 2.0 and IEC 61850-7-420, edition 1.0. As shown in Table I, the three upper rows are IEC 61850 data models for information sent from DR units towards SCADA; the bottom row is the data model for room temperature set-point control command, sent from SCADA towards DR units.

Furthermore, in this DR scheme, SCADA needs to know the location where the DR unit is installed. For a utility the location would be the customer or meter id that associates the DR unit to secondary substation. For other Aggregator like a local industry, it could be street address or other id. Besides,

TABLE II
IEC 61850 DATA MODELS FOR THE DR UNIT (PART 2)

Data sent from DR Unit	Logical Node class	Data Object	Common Data Class	Data Attribute
location	LPHD	PhyNam	DPL	location
IP address	LPHD	PhyNam	DPL	*serNum*

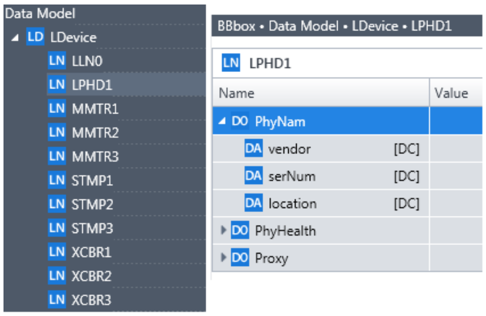

Figure 2. IEC61850 Data Models for DR Unit (screenshot from IEDScout)

SCADA needs to know IP address of the DR unit – as will be shortly explained, the IP address is needed for realizing auto-detection and auto-configuration mechanism. These information are mapped to IEC 61850 data models as in Table II. Note that in IEC 61850 standard, the Data Attribute "serNum" is intended for serial number instead of IP address. But it is "borrowed" here for modeling IP address, otherwise additional extension needs to be added to LPHD Logical Node.

The overall IEC 61850 data models for one DR unit is depicted in Figure 2. This DR unit can control a residential house with three rooms, each room installed with one controllable heating load. In Figure 2, the whole DR unit is mapped to one Physical Device and one Logical Device (LD), which contains 11 LNs. Among them are three MMTRs, STMPs and XCBRs, each of which for one room. In case the house has more room heating, additional MMTR, STMP and XCBR LNs are added.

C. Step 2: Mapping to IEC 61850 Communication Services

One challenge this paper tries to tackle is: how to provide some kind of dynamic system management mechanism that can allow each individual DR unit being automatically detected, registered and integrated into existing DR system – ideally, through only its IP address?

This kind of auto-detection and auto-configuration mechanism is especially useful for wide scale deployment of DR scheme. It is worth mentioning that although the upcoming IEC 61850-90-15 standard will include a number of administration functions for the registry of DER units, the auto-detection, auto-configuration service is lacking in this standard [2].

The DR communication solution in this paper realizes the auto-detection, auto-configuration service by multicasting GOOSE (Generic Object Oriented Substation Event) messages in an unconventional way. The solution looks like Figure 3.

As shown in Figure 3, each individual DR unit announces its IP address by sending GOOSE messages across the

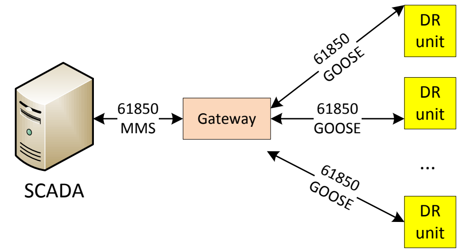

Figure 3. Using GOOSE Communication to realize auto-detection and auto-configuration

communication network. The receiver (subscriber) of these GOOSE messages is one gateway, which sits between DR units and SCADA. This gateway maintains a simple form of registry for all DR units. If the received GOOSE message contains a new IP address, then the gateway knows a new DR unit has arrived, and as a result, it adds this new DR unit's IP address to its registry. In this way, DR units are registered to the gateway with almost zero-configuration.

This is a very different way of using GOOSE communication, as GOOSE is commonly used for IED-IED communications (i.e., so-called horizontal communication), in applications like protection. However, the multicast, publisher/subscriber and peer-to-peer style of messaging pattern offered by GOOSE provides a straightforward solution to automatically integrate DR units with the rest of DR system.

In addition to IP address, each DR unit also multicasts measurement values (including room temperature and connected heating load) though GOOSE messages. These GOOSE messages are received by the gateway, which then forwards these measurements to SCADA using IEC 61850 Reporting service.

This is again a nontraditional way of using IEC 61850. For sending data from IEDs to gateways or directly to SCADA (i.e., vertical communication), it is common to adopt IEC 61850 MMS client-server communication, using services like Reporting and Read. In this DR communication scenario, however, if directly transmitting measurements from DR units to SCADA using Reporting or Read service, there will be scalability issue – the IEC 61850 client (in this case, SCADA) needs to have the IP address for each server (i.e., DR unit) pre-configured, before it can start polling data or receiving reports from each DR unit. This will result in tremendous configuration overhead when hundreds or thousands of DR units are integrated to the DR system.

In the other direction, to issue temperature decrease command, the SCADA first sends the temperature set-point to gateway by using IEC 61850 Write service (MMS client-server communication). The gateway then multicasts this information by publishing GOOSE messages, which are received by all DR units. DR units will then lower their temperature set-point.

This communication and aggregation solution implies that

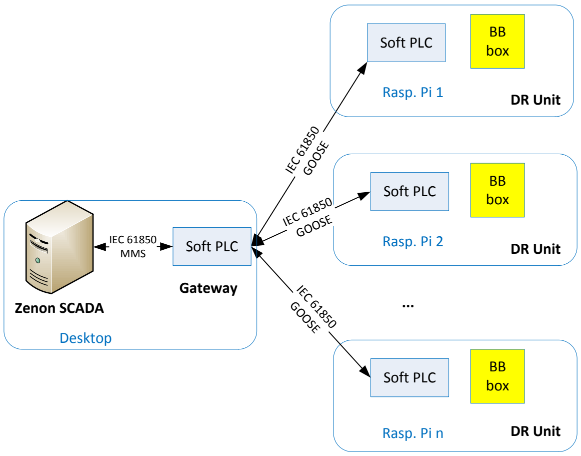

Figure 4. Implementation architecture of the DR communication solution

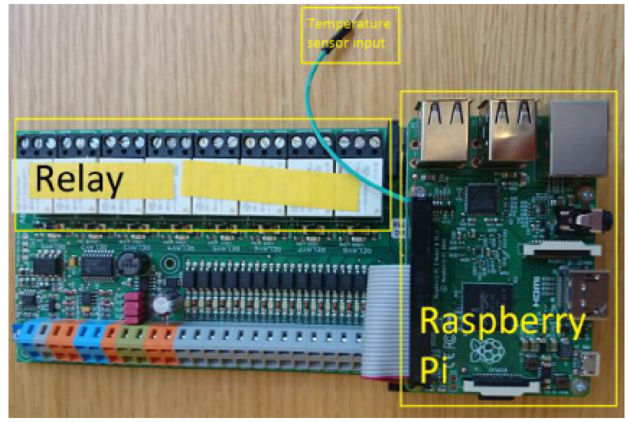

Figure 5. Implementation of DR unit on Raspberry Pi single-board computer (with relays and temperature sensor input for controlling electric radiators or floor heating in eight rooms)

the SCADA needs to have 61850 client interface, which is nowadays becoming more and more common. Furthermore, every DR unit, as well as the gateway, needs to contain a built-in IEC 61850 server. The gateway has the similar 61850 data models as DR unit, as presented in Section III-B.

IV. IT System Implementation

This DR communication solution is implemented as a flexible, multi-level, hierarchical structure as illustrated by Figure 4. It consists of three layers – DR units, Gateway and SCADA,

- DR unit – The whole DR unit is running on Raspberry Pi (a credit card-sized single-board computer). It contains two parts, one is functionality part, called “BBbox”; the other is IEC 61850 interface, implemented in a commercial soft PLC (programmable logic controller) system [14].
- Gateway – It is also implemented in a soft PLC system. It functions as a communication middlebox that allows DR units to integrate with SCADA using GOOSE.
- SCADA – a commercial SCADA system called “Zenon SCADA”.

A. DR Unit

The DR unit looks like Figure 5, and can be installed at residential house. Its functionality part, BBbox, is a spatial heating controller, which plans and controls residential heating. It is built on top of a Raspberry Pi, connected with several temperature sensors and relays (one for each room) [7].

When planning room temperature set-points for the next 24 hours, BBbox takes into account three factors. The first is acceptable maximum and minimum temperature for each room, which is configured by customers through Web interface. The second is electricity price. The temperature is set lower during those hours with expensive electricity price, but before and after these hours, it is set higher. By original design, BBbox retrieves electricity spot price by sending request to Nordspot server every afternoon. However, for those customers who participate in the community-wide DR scheme, this request is redirected to a local FTP server, which provides locally manipulated market price as explained in Section II-B. The third factor is temperature decrease commands issued by Aggregator’s SCADA. This only applies to the next 4 hours.

The control of room heating is realized by automatically switching on or off the relay according to temperature set-point and its real-time measurement.

The second part of DR unit is IEC 61850 interface, which contains a built-in IEC 61850 server for sending and receiving GOOSE messages as described in Section III-C. The IEC 61850 server is implemented in a commercial soft PLC system, deployed on the same Raspberry Pi that runs BBbox.

B. Gateway

Similar as DR unit IEC 61850 communication interface, the gateway also has a built-in IEC 61850 server, and is implemented in a soft PLC system. In current prototype implementation, the gateway is configured and maintained from the same commercial engineering environment as the SCADA [14], and it is deployed on the same desktop computer as the SCADA run-time application. But it could also run independently on a PLC system, installed at substation for instance.

Figure 6 and Figure 7 are screenshots captured during runtime testings for GOOSE communications between the gateway and DR unit. Figure 6 shows the GOOSE message sent out by DR unit, which broadcasts its own IP address. The lower part of this figure highlights the GOOSE Control Block for this message. Figure 7 is a screenshot taken from the soft PLC runtime environment which implements the gateway. It shows the GOOSE message containing IP address of a DR unit has been received by the gateway.

C. SCADA

The SCADA system has a IEC 61850 client driver, which allows it to conduct IEC 61850 MMS communication with Gateway. To realize the community-wide DR scheme, some

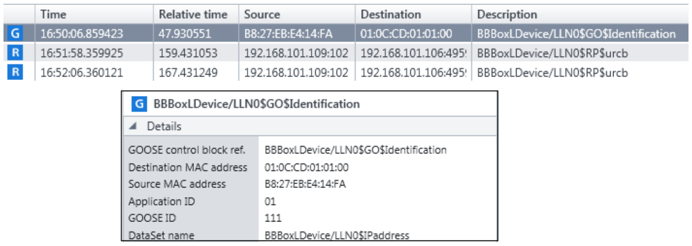

Figure 6. A GOOSE message is captured by IEC61850 traffic sniffer tool. This message is sent out by DR unit. The lower part of this figure shows the GOOSE Control Block for multicasting IP address.

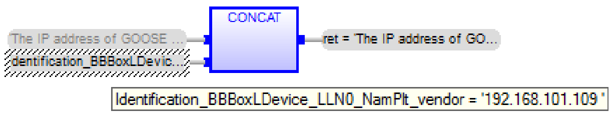

Figure 7. The GOOSE message is received by the gateway. The gateway is also implemented on a soft PLC system.

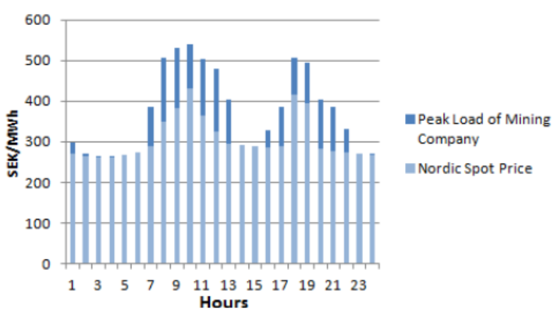

Figure 8. Local electricity price manipulation is implemented as one function in SCADA system

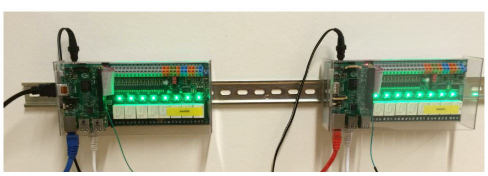

Figure 9. Installation setup of two DR units at STRI's VPP test bed

additional functions are implemented in the SCADA, including data aggregation, shiftable loads calculation, and local price manipulation. Figure 8 shows the screenshot of the price manipulation function implemented in Zenon SCADA. The manipulated price can then be hosted on a local FTP server.

Be design, the SCADA is deployed at Aggregator's control room. In prototype implementation, the SCADA system, together with the gateway and a dozen of DR units, are installed in STRI's Virtual Power Plant (VPP) test bed. Figure 9 is a picture of the installation of two DR units in the VPP test bed.

V. Future work and Conclusion

In the final deployment, both SCADA and the gateway will be on the Aggregator's WAN (wide area network). IT-security firewall functionality is required in the gateway as it is a zone border between high security operation network of the Aggregator and low security extension of the WAN extending to end-customer DR units. Also in the final implementation, DR units are to be pre-configured with a VPN tunnel to access this network, similar as defined in VHPReady [10].

To summarize, this paper presents an IEC 61850-based communication and integration solution for Demand-Response systems, and applies it to one community-wide DR application. This "auto-detection", "auto-configuration" communication solution enables seamless integration of DR end devices, with no need for manual configuration of individual DR end device when it entering or leaving the DR scheme. This dramatically increases the efficiency of system integration, making large scale of DR deployment feasible. The same solution could also be applied to other sources such as EV chargers and home battery energy storage systems connected to PV generation.

This DR communication solution is implemented in a flexible, three-layer architecture consisting of SCADA, gateway and low cost DR end devices. The DR end device hardware costs just 100 EUR (Raspberry Pi plus sensors and relays), and installation cost is estimated at 2 hours per house.

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Research Article

Hierarchical and distributed control concept for distribution network congestion management

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Abstract: Congestion management is one of the core enablers of smart distribution systems where distributed energy resources are utilised in network control to enable cost-effective network interconnection of distributed generation (DG) and better utilisation of network assets. The primary aim of congestion management is to prevent voltage violations and network overloading. Congestion management algorithms can also be used to optimise the network state. This study proposes a hierarchical and distributed congestion management concept for future distribution networks having large-scale DG and other controllable resources in MV and LV networks. The control concept aims at operating the network at minimum costs while retaining an acceptable network state. The hierarchy consists of three levels: primary controllers operate based on local measurements, secondary control optimises the set points of the primary controllers in real-time and tertiary control utilises load and production forecasts as its inputs and realises network reconfiguration algorithm and connection to the market. Primary controllers are located at the connection point of the controllable resource, secondary controllers at primary and secondary substations and tertiary control at the control centre. Hence, the control is spatially distributed and operates in different time frames.

1 Introduction

The amount of distributed generation (DG) is constantly increasing and other controllable resources such as controllable loads, electric vehicles and energy storages are becoming more common in distribution networks. At present, the control possibilities of these resources are not utilised in distribution network operation and network reinforcement is used to solve problems caused by DG. Active network management methods can also be used to mitigate voltage rise caused by DG or prevent network overloading. In many cases, the active congestion management methods lead to considerably lower network total costs than the currently used passive approach [1].

Distribution network congestion management has been studied extensively in the past years. The proposed methods range from simple methods based only on local measurements (e.g. local reactive power control of DG units) to advanced methods utilising all DERs in a coordinated manner. Two approaches to coordinate the controllable resources have been proposed in publications. Methods can operate in real-time based on measurements or state estimation data (e.g. [2–17]) or predetermine a control schedule for the controllable resources based on forecasted load and production (e.g. [18–21]) or combine the two approaches [22]. The challenges are different depending on the selected approach. In the methods operating in real-time, the algorithm convergence needs to be guaranteed and the execution time has to be short enough. Moreover, the real-time algorithms often operate based only on the current network state and, hence, do not necessarily find the overall optimal operation of the network. For instance, consecutive on-load tap changer (OLTC) operations can be initiated although the momentary network condition change could have been managed also without OLTC operations. In the methods that operate based on forecasts, the execution time is not that critical and it is possible to consider the whole control horizon in the calculations. The accuracy of these methods, however, depends on the accuracy of the load and production forecasts. Without any real-time control part, they are not adequate for congestion management purposes since the congestions always need to be removed to avoid unacceptable voltage quality or network component overloading that can cause malfunction of customer equipment or even breakdown of network components or customer devices. The forecasts always have uncertainty and, hence, responsibility on guaranteeing an acceptable network state cannot be given to algorithms operating only based on forecasts.

The coordinated congestion management methods can be divided into centralised and distributed methods. In centralised methods (e.g. [2–13]), measurement data is gathered to one point in the network (usually the control centre), control decisions are made based on that data and control commands are then sent to the controllable resources. The advantages of centralised methods are that they can take into account the whole network when determining the control actions and that they can be relatively easily integrated into existing systems of distribution system operators (DSOs). The amount of input measurement data and controllable resources that they can handle is, however, limited by data transfer and computational limitations, i.e. they are not particularly scalable. They are also vulnerable to component failures since all the data transfer is to and from one centralised controller. In the distributed methods (e.g. [14–17]), the intelligence is distributed to several points in the network. The distributed methods are more scalable and more robust to component failures since a single component is not responsible for controlling the whole network. On the other hand, in distributed methods the controllers do not have a global view of the system and might not be able to find a global optimum for the system.

The congestion management concept proposed in this paper is hierarchical and distributed. The control hierarchy has three levels that are located in different places, operate in different time frames and utilise different types of input data. The architecture combines the advantages of centralised and distributed methods and includes algorithms operating both in real-time and based on forecasts. Also the DSO's interface to the market is defined which is often omitted in congestion management studies. The control concept is scalable and modular and enables easy addition of new DERs to the system.

2 Distributed automation architecture and control system hierarchy

The proposed congestion management concept operates on a distributed automation architecture represented in Fig. 1. Currently DSOs conduct all network operations from the control centre using distribution management system (DMS) and SCADA. In the proposed distributed automation architecture [23], many of the monitoring and control functionalities are executed in substation automation units (SAUs) located at primary and secondary substations. Primary SAUs (PSAUs) are responsible for the MV network and secondary SAUs (SSAUs) take care of the LV network. The SAUs include control functions, a database for storing and exchanging information and interfaces to measurement devices, controllable resources, other SAUs and in case of PSAUs to the control centre. New functionality is added also to the control centre.

The control system hierarchy consists of primary, secondary and tertiary controllers. Primary controllers such as automatic voltage control relays of the OLTCs, real and reactive power controllers of DG units, reactive power controllers of reactive power compensators and real power controllers of controllable loads are located next to the controllable resource and are the most distributed part of the control hierarchy. They operate independently based only on local measurements and, therefore, respond immediately to disturbances. The set points of primary controllers can be adjusted remotely. These devices already exist in the distribution networks, but are used with a constant set point.

Secondary controllers are located at PSAUs and SSAUs depending on which network, MV or LV, they are managing. They operate in real-time and their primary aim is to keep the network state acceptable in all loading and generation situations. As a secondary goal they aim at optimising the network state. Secondary control operates through changing the set points of primary controllers and needs information on the current network state as its input.

Tertiary control is located at the control centre and can be implemented as a part of the current DMS or as an individual controller. While primary and secondary controllers operate in real-time, the tertiary controller operates day-ahead based on the load and production forecasts. The tertiary controller consists of several functionalities: The network reconfiguration algorithm determines the optimal network topology for the next 24 h based on forecasted states of the network. Tertiary control is responsible also for interactions with the market operators. It purchases

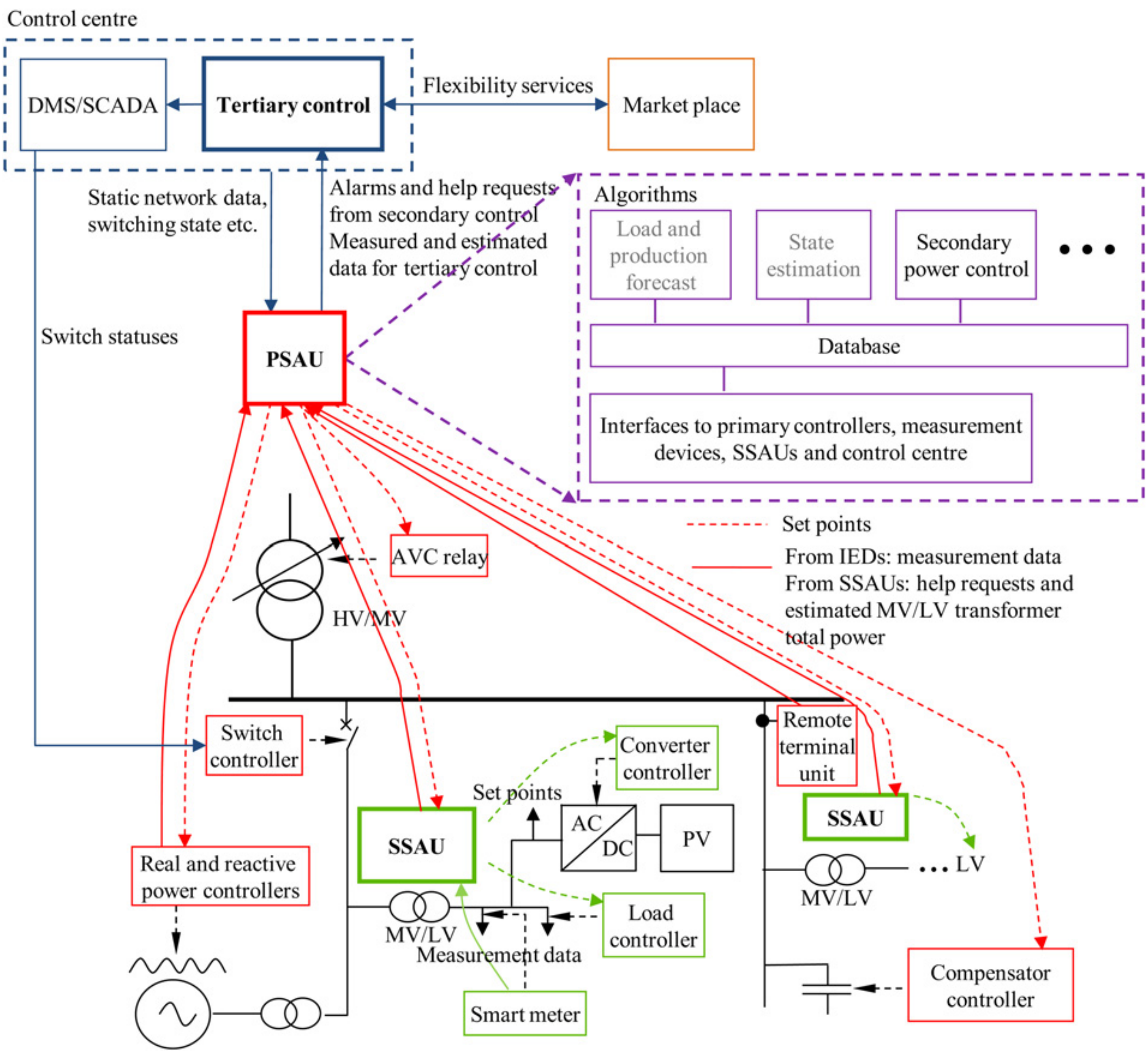

Fig. 1 *Distributed automation architecture and data flows between different components. Parts of the automation architecture that are proposed to be added to the current systems are bolded*

flexibility services from the flexibility market if needed to solve congestions during the following 24 h. It also validates the flexibility products procured by other actors than the DSO. Also real-time operation can be requested from the tertiary controller in certain situations. In post-fault situations, network reconfiguration algorithm is used to maximise the area which can be supplied through backup connections. The secondary control can also send a help request to the tertiary control if it is unable to keep its network in an acceptable state. Due to scalability reasons the tertiary controller considers only the MV network.

In the distributed control architecture each SAU is responsible for monitoring and controlling either one MV or one LV network which makes the system scalable. In a centralised approach the data transfer to and from the control centre is directly proportional to the size of the controlled network and the number of controllable resources. Also, very high computational capacity would be required to calculate the state estimates and optimal primary controller set points in real-time for the whole distribution network. In the distributed approach the amount of data transfer is significantly reduced as only necessary data is transferred between the different level SAUs and the control centre.

The control architecture and SAU implementation is such that adding a new controllable resource to the network is simple. The static data model of the DER needs to be added to the database of the SAU to whose network the resource is connected and the interface between the SAU and the primary controller of the DER needs to be configured. The SAU database utilises standardised data models (IEC 61850 and CIM) which enhances the interoperability of the system. As soon as the information on the new DER is available in the SAU database, the SAU algorithms read the data from the database and start to utilise the DER. Relevant information on the new resource is automatically sent to other SAUs and to the control centre using CIM data exchange.

All information exchange inside the SAU is realised through the database. Hence, the SAU implementation is modular and the internal implementation of each function can be easily replaced with another implementation as long as the database interface remains intact.

3 Interactions of the control system

The proposed control hierarchy operates in different time frames and utilises different types of input data. Moreover, the different hierarchical levels (primary, secondary, tertiary) consist of several different functionalities. The different parts of the control system need to operate in correct order and exchange relevant information to achieve good control performance. The detailed description of interactions between the hierarchical levels of the control system and the functioning of the congestion management in different time frames is presented in Fig. 2. The time frames consist of three slots called day-ahead, intra-hour, and real-time. Different functionalities of the controllers are presented in separate blocks in order to illustrate the interactions of the control system more

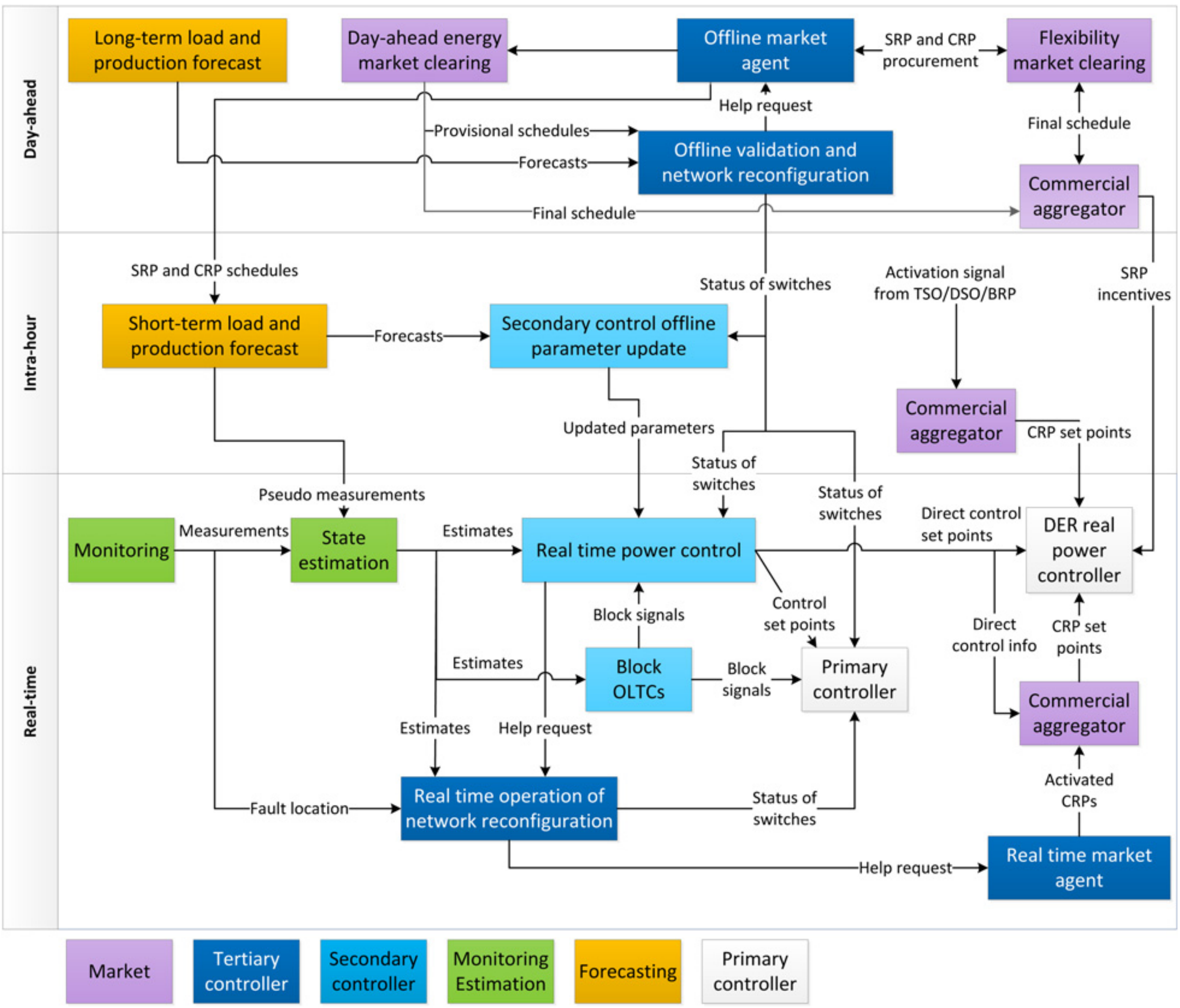

Fig. 2 *Detailed interactions of the hierarchical congestion management system*

clearly. Also supporting functionalities such as forecasting, monitoring/estimation and market functionalities are depicted in Fig. 2 to achieve a complete view on the system operation. The aim of the whole control system is to prevent network congestions and to minimise the network total costs. If real-power control of DERs is needed (production curtailment or load shedding), operating through the market operators is preferred, but also direct control of real power is possible in emergency situations.

3.1 Day-ahead time frame

The sequence of congestion management starts before day-ahead market closing. After the market bidding process, the DSO validates whether the proposed load and production schedules lead to congestions in the distribution network. If congestions do not exist, the market is closed. Otherwise the tertiary control takes action to prevent the forecasted congestions. At first, it aims to solve the congestions using the network reconfiguration algorithm. The algorithm directly controls only the switching state of the distribution network, but considers also the expected secondary control actions regarding other DERs such as transformer OLTCs and reactive power control devices when validating network state acceptability and determining its control actions. Real-power control of DERs is not utilised at this point. If network switching state is changed, the new network topology is communicated to secondary control.

If the network reconfiguration algorithm is unable to solve network congestions, it sends an execution request to the tertiary control market agent. The market agent aims at finding the cheapest solution to solve network congestions using market tools. It can purchase scheduled and/or conditional re-profiling (SRPs and/or CRPs) services [24] from commercial aggregators in the day-ahead flexibility market or reject energy bids from the day-ahead market. The flexibility market does not exist yet and before it is available bilateral contracts can be used to procure flexibility products. Scheduled re-profiling means that a DER offers to produce/consume an assigned power during an assigned period of time and conditional re-profiling means that a DER offers to be ready to change its production/consumption in a certain range at an assigned period of time [24].

After finalising its operation, the market agent informs the short-term load and production forecast about purchased flexibility services in order to adapt intraday and intra-hour forecasts. The commercial aggregator combines the information on the accepted bids received from the day-ahead energy market and flexibility market clearing to create its final schedule. The price incentives are then sent to the consumers/prosumers in order to activate SRPs.

3.2 Intra-hour time frame

The intra-hour time frame contains three functionalities. The short-term load and production forecast is executed to produce pseudo measurements for the state estimator [25] operating in real-time. The commercial aggregator can receive CRP activation requests from other actors such as transmission system operators and balance responsible parties during the intra-hour time frame. From congestion management point of view, the most significant operation during the intra-hour time frame is the offline cost parameter update of secondary control which aims at preventing unnecessary OLTC actions. This function uses the forecasted load and production data to examine and modify the operation of the real-time secondary power control based on a longer time period and not only on single time step as is done in the real-time control part.

3.3 Real-time time frame

The real-time operations of the control architecture consist of monitoring, state estimation and primary and secondary controllers. Also tertiary control includes a real-time part. Monitoring, state estimation and secondary power control operate on an SAU (see Fig. 1 for SAU structure) that is responsible for a single MV or LV network. The monitoring functionality collects all measurement and status information from the control area. Since measurements are not usually available from every distribution network node and because they can have errors, state estimation is needed to provide necessary inputs to the secondary power control. In network nodes where measurement data is not available, the state estimator utilises pseudo measurements. In the proposed control architecture, the pseudo measurements are produced by the short-term load and production forecaster which also takes weather data into account. If the forecaster output is not available, fixed load and production profiles obtained from smart metering data are used as pseudo measurements.

The secondary controller operates through changing the set points of primary controllers. The controllable variables can be divided into two categories: The variables whose operation is optimised only by the secondary controller such as transformer OLTCs and reactive power resources and the variables that are preferably controlled by tertiary control through the market and by the secondary control only in emergency situations. The emergency mode of the secondary controller is activated if the congestion remains for a predefined time (e.g. 15 min). The required response time depends on the type and severity of the congestion and for instance in case of component overloading on the thermo-dynamic time constant of the overloaded component. The different types of control variables are indicated in Fig. 2 by representing DER real power controllers with an own block although they are also primary controllers. It should be noted that a DER can include both types of control variables. For example, for DG, reactive power control capability can be a network interconnection requirement, but real-power control available only in emergency situations. If the DG connection contract is non-firm [26], also real-power control can belong to the first group of variables. The commercial aggregator is informed of the direct real-power control implemented by secondary control.

The real-time parts of tertiary control are executed only by request in post-fault situations or when the MV network secondary control is unable to solve congestion problems in its network. In real-time operation, tertiary control utilises network reconfiguration first and if congestion remains after network reconfiguration, the market agent is activated. The real-time market agent operates through activating previously bought CRPs. Since the real-time tertiary control operates only by request, no conflicts between real-time secondary and tertiary control can occur. The secondary control is suspended during fault location, isolation and supply restoration.

4 Secondary control

The primary objective of the secondary control is to mitigate congestions in the distribution network, i.e. to keep network voltages between acceptable limits and feeder and transformer currents below the thermal limits. The second objective of the secondary control is to minimise the total costs of the network. The proposed secondary control consists of three parts (see Fig. 2): Real-time power control is the actual optimisation algorithm that controls the primary controller set points. It aims to keep the network in an acceptable state and to optimise its operation based on the current network state. Secondary control offline parameter update and block OLTCs are supplementary parts aiming to prevent unnecessary control actions such as multiple OLTC actions during a short period of time. Reliable, correct and relatively fast operation of the real-time power control is vital to the distribution network because if this algorithm fails the network can remain in an unacceptable network state. Hence, it is the most important part of the secondary control. The other parts enhance the operation of the control system, but are not critical to the distribution system operation.

The control architecture is modular and each algorithm is implemented as its own independent instance. All data transfer goes through the database and database flags are used to coordinate the operation between different algorithms (e.g. state estimation results need to be available before real-time power

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control can be executed). The implementation is such that if either of the non-critical secondary control algorithms (secondary control offline parameter update or block OLTCs) fails, the real-time power control still operates.

4.1 Real-time power control

The implemented real-time power control algorithm solves an optimal power flow (OPF) problem. The optimisation of distribution network operation is a mixed integer non-linear programming (MINLP) problem

$$\begin{aligned} \text{minimise} \quad & f(\boldsymbol{x}, \boldsymbol{u}_\text{d}, \boldsymbol{u}_\text{c}) \\ \text{subject to} \quad & g(\boldsymbol{x}, \boldsymbol{u}_\text{d}, \boldsymbol{u}_\text{c}) = 0 \\ & h(\boldsymbol{x}, \boldsymbol{u}_\text{d}, \boldsymbol{u}_\text{c}) \le 0 \end{aligned} \tag{1}$$

where $\boldsymbol{x}$ is the vector of dependent variables, $\boldsymbol{u}_\text{d}$ is the vector of discrete control variables and $\boldsymbol{u}_\text{c}$ is the vector of continuous control variables. The optimisation aims to minimise the objective function $f(\boldsymbol{x}, \boldsymbol{u}_\text{d}, \boldsymbol{u}_\text{c})$ subject to equality constraints $g(\boldsymbol{x}, \boldsymbol{u}_\text{d}, \boldsymbol{u}_\text{c}) = 0$ and inequality constraints $h(\boldsymbol{x}, \boldsymbol{u}_\text{d}, \boldsymbol{u}_\text{c}) \le 0$ [27].

In the implemented real-time power control algorithm, nonlinear programming is used to solve the MINLP problem and a heuristic method is used to assign the discrete variables [4, 28]. The controllable variables are transformer OLTC positions, real and reactive powers of distributed generators, reactive powers of reactive power compensators and real powers of controllable loads. The algorithm is implemented as an Octave program [29] and utilises the sequential quadratic programming solver of Octave.

The vector of dependent variables consists of voltage magnitudes and angles of all distribution network nodes. The continuous variables are DG real powers, reactive powers of controllable resources and real power changes of controllable loads. The only discrete variable is the transformer tap changer. The objective function is formulated to minimise network losses, production curtailment, load control actions, the number of OLTC operations and the voltage variation at each node. Feeder voltage limits, branch current limits and the constraints on control variables (e.g. reactive power limits of DG) are taken into account in the inequality constraints of the OPF and the equality constraints model the power flow equations at each network node. The full formulation of the optimisation problem can be found in [4, 28].

The output of an optimisation algorithm depends on the objective function and, hence, the operational principles of the implemented control algorithm can be determined by selecting suitable objective function weighting factors, i.e. cost parameters. In the proposed method, the cost parameters are selected such that real-power control is used only as a last resort and they can be altered by the cost parameter update function.

The real-time power control algorithms are located at SSAUs and PSAUs and optimise the set points of primary controllers connected to the network of that SAU. Static network data (e.g. feeder parameters, switching state etc.), state estimation results and data on the controllable resources is needed as input to the algorithm.

4.2 Offline cost parameter update

Secondary control offline parameter update determines the cost parameter values used in the real-time power control objective function. It utilises load and production forecasts as its input and its purpose is to prevent unnecessary control actions. The proposed control algorithm concentrates on preventing continuous OLTC actions. The algorithm uses load and production forecasts to determine the control actions that the real-time power control algorithm will take in future time steps. If it observes frequent OLTC operations back and forth, it changes the optimisation function cost parameters such that other resources than the OLTC are used during the short-term changes in the network state. In practice this means that the weighting factor for OLTC operation is increased. Other objectives could also be taken into account in the cost parameter update function. Due to the modular implementation, only the internal implementation of the function would need to be changed to implement different objectives. The parameter update functions are located both at PSAUs and SSAUs similarly as the real-time power control functions [28].

4.3 Block OLTCs

Since the secondary controllers only utilise information of one MV or LV network in their operation, adverse interactions between the controllers can occur. The most problematic case is when there are cascaded transformer OLTCs in the network, i.e. also the secondary substation has a tap changer. For these cases, a coordinating function (in Fig. 2 Block OLTCs) is proposed. The block OLTCs unit is located at the PSAU and sends block signals to the SSAU real-time power control algorithms and the AVC relays of MV/LV transformers when the HV/MV OLTC is operating to avoid back-and-forth operation of the MV/LV OLTCs. The same operation could be obtained also by traditional time grading of cascaded OLTCs [30]. The benefit of the block OLTCs unit is the enhancement of power quality during rapid changes, but requires fast real-time monitoring of the network. In many cases, time grading is an equally good solution [28, 31].

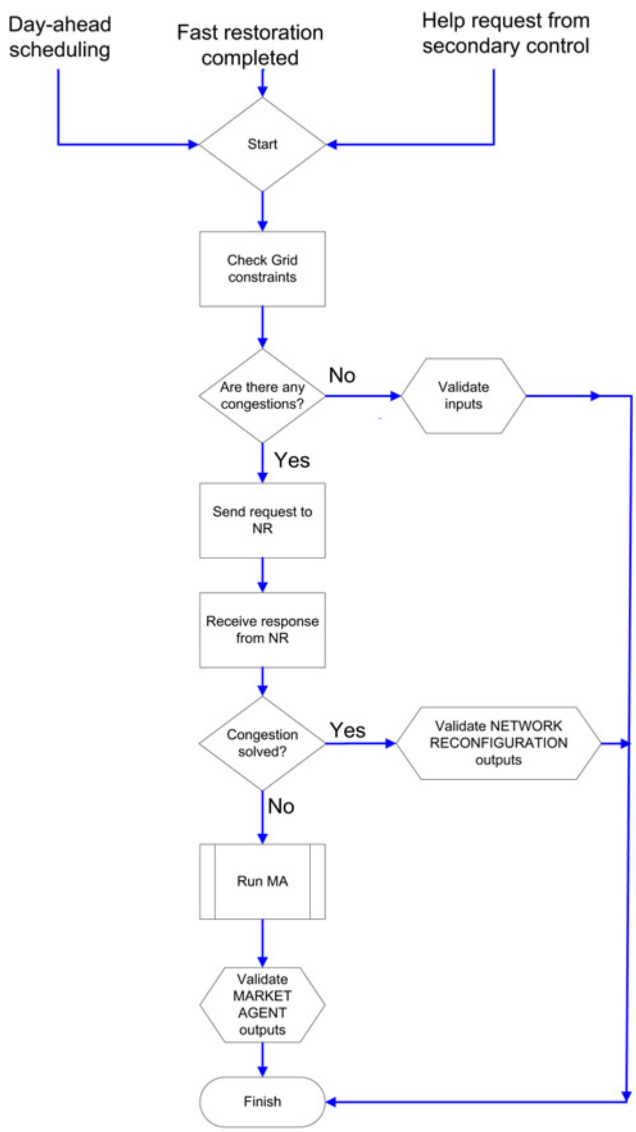

Fig. 3 *General flowchart of tertiary controller functions*

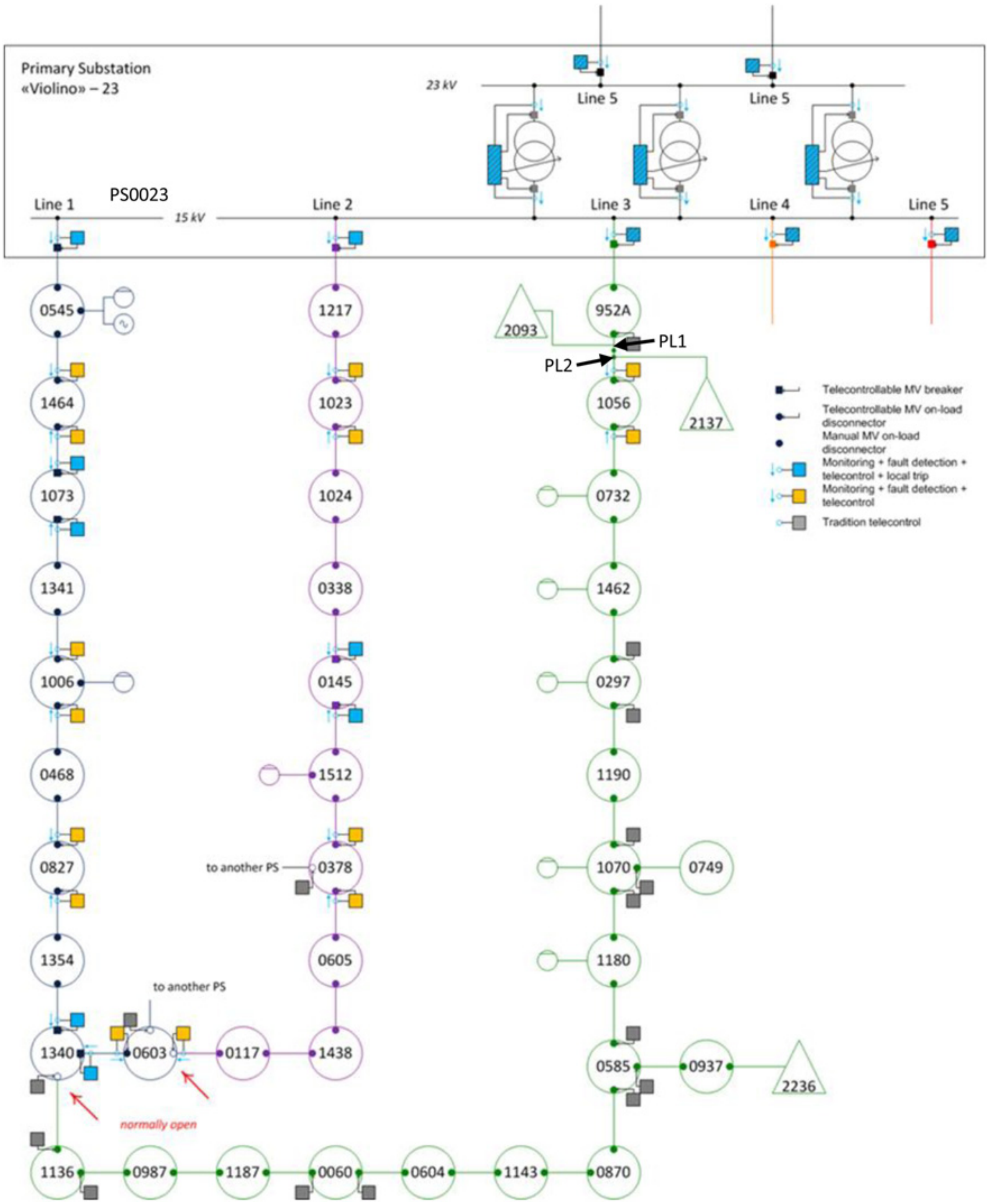

Fig. 4 *Unareti MV network*

5 Tertiary control

The tertiary control functions are implemented on control centre level and consider only the MV network. Tertiary control consists of network reconfiguration (NR) and market agent (MA) algorithms and the general flowchart of tertiary control is represented in Fig. 3.

The tertiary controller operates both in offline mode (day-ahead scheduling) and in real-time mode. The day-ahead scheduling is triggered before the day-ahead market closing when provisional aggregated generation/demand schedule is available. The real-time operation can be triggered either by the fault location, isolation and supply restoration (FLISR) algorithm (fast restoration completed message) or by the secondary MV network control (help request from secondary control). The tertiary control uses network reconfiguration as primary means to solve detected congestions. If the NR algorithm is not able to find a network topology that removes all congestions, the market agent algorithm that utilises flexibility products to solve the congestion is invoked. When all congestions have been removed, the network topology and the generation/demand schedule are validated. If congestions remain also after MA algorithm operation, an alarm signal is sent to the operator.

5.1 Network reconfiguration

The goal of the NR algorithm is to change the topological structure of the distribution feeders by closing some normally open switches and opening some normally closed switches in their place. The network configuration should remain radial after the switching operations. The problem of distribution network reconfiguration is a highly complex, combinatorial, non-differentiable MINLP optimisation

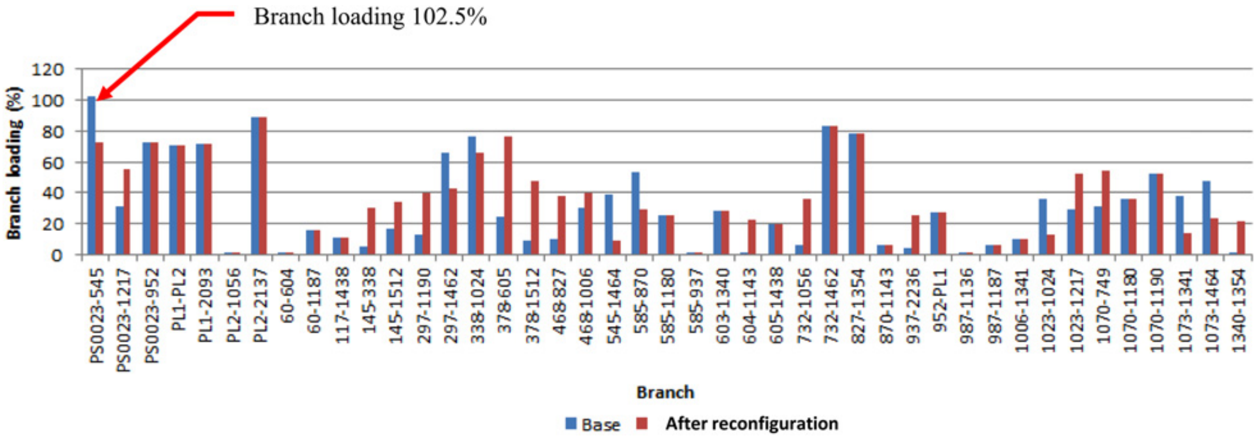

Fig. 5 *Branch loading before and after applying the network reconfiguration algorithm*

problem because of the large number of discrete switching elements [32]. In addition, the radial constraint typically introduces additional complexity in the reconfiguration problem for large distribution networks [33]. Classical methods such as mixed-integer linear programming have been used for solving reconfiguration problems in large-scale distribution systems, but these methods are prone to converge to a local minimum and not to the global minimum. Heuristic algorithms have been applied to the problem of network reconfiguration for loss reduction in several studies (e.g. [34]). The radial topology constraint of the system is imposed implicitly by the heuristic algorithms and not explicitly in the model. Evolutionary algorithms, genetic algorithms, simulated annealing and ant colony optimisation are examples of heuristic algorithms that have been used for network reconfiguration.

In the proposed control scheme, the tertiary controller finds the optimal network configuration by means of genetic algorithms. The optimisation problem minimises network losses and switch operations. The optimal topology found by the NR must be radial and keep voltage and branch current within established limits. The expected secondary control actions are taken into account in the optimisation but only switch statuses are directly controlled by the NR algorithm. Static network data (e.g. feeder parameters, switching state etc.), state estimation results (in real-time operation) or load and production forecaster results (in offline mode), fault details (in post-fault operation) and operational costs are needed as inputs to the algorithm [28].

In offline mode, NR algorithm will be executed to reduce system losses, balance loads (exchange between feeders) and avoid overload of network elements. In post-fault situations the NR algorithm is run after the FLISR algorithm has completed its operation. It aims to restore the remaining unrestored customers and to solve congestions (voltage violations or component overloading) caused by the fast restoration (FLISR). If a help request is received from the secondary control, the NR algorithm tries to solve congestions that the secondary control was unable to solve.

5.2 Market agent

The market agent utilises flexibility services (SRPs and CRPs [24]) for MV network congestion management. Its main objective is to propose changes of scheduled generation/demand values of DER units through flexibility offers/bids to provide a feasible combination of schedules. Also the market agent solves an OPF problem. The controllable variables are the DER real power changes activated by the purchased flexibility products and the objective function is formulated to minimise the cost of purchased flexibility products. The algorithm is implemented as a Matlab program and utilises the primal/dual interior point solver of Matlab [28].

The operation of the MA algorithm is different in offline and real-time modes since different flexibility services are available depending on the time frame. In the offline mode, the market agent can purchase SRPs and CRPs from the flexibility market or reject energy bids from the day-ahead market. As an input, the offline MA needs static network data, load and production forecasts, the provisional schedule from the market and the market clearing prices. In the real-time mode, the MA can activate previously purchased CRPs. State estimation data is used as an input instead of the forecast data [28].

6 Simulation results

The operation of the proposed control framework is demonstrated using simulations of one example distribution network. The study network is a real distribution network of the Italian DSO Unareti and is located in Brescia. The study MV network consists of three 15 kV feeders ranging from the same primary substation and is depicted in Fig. 4. In the MV network model, the low voltage customers are aggregated at the MV/LV substations. A detailed

Table 1 Power factor and decomposition into flexible and non-flexible demand for each load type

Load type	Power factor	Fixed, %	Flexible, %
domestic	0.9	59	41
non-domestic (LV)	0.9	53	47
MV load	0.95	53	47

Table 2 Price of flexibility by type of consumer

Type of flexibility	Flexibility price, €/kWh
domestic consumers	0.15
non-domestic consumers	0.12[a]
MV consumers	0.09

[a]Obtained by interpolation.

Table 3 Flexibility used per node

Node	Flexibility, kW	Node	Flexibility, kW
60	26.4	1056	13.7
297	15.1	1070	18.6
585	3.7	1136	31.2
604	6.1	1143	7.8
732	6.2	1180	21.3
749	11.1	1187	3.9
870	7.2	1190	1.5
937	1.2	1462	6.2
987	39.2	2236	0.9

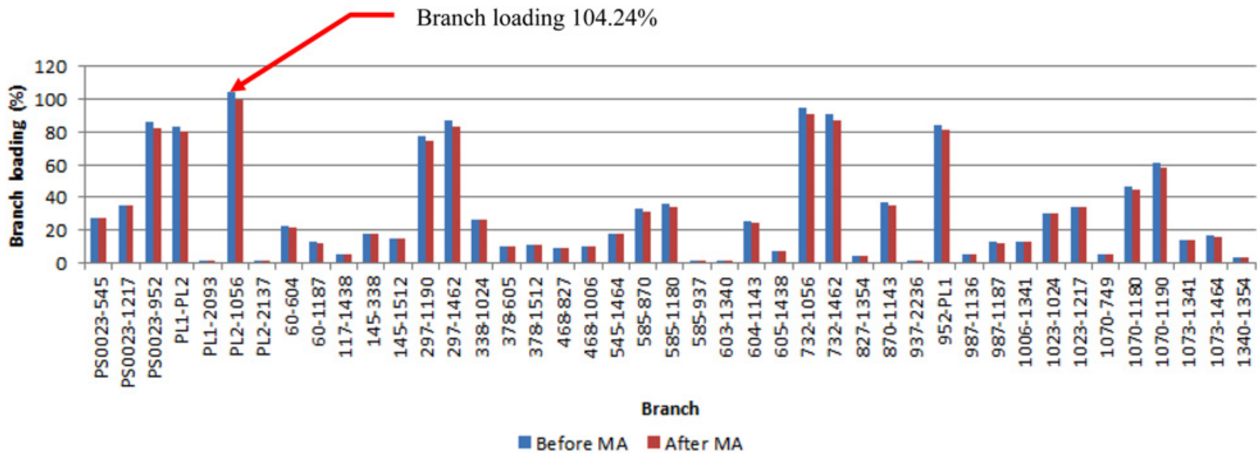

Fig. 6 *Branch loading before and after applying the market agent*

model of one of the LV networks (connected to MV network node 1056) is also composed to enable simulating the LV network operation of secondary control.

The simulation cases have been selected such that the demonstrated parts of the hierarchical congestion management system are the day-ahead operation of the tertiary control and the real-time operation of the secondary control.

6.1 Tertiary control results

The tertiary control operates only on MV network level and the network model of Fig. 4 has been used to test its operation. The day-ahead operation of the tertiary controller has been simulated using a high demand scenario of a winter day in January. Load and production forecasts for 24 h have been composed and the tertiary controller runs a load flow for each of the forecasted hours to determine whether congestions are foreseen. The voltage limits are set to ±5% and the real nominal capacities of lines and transformers are used in the simulations as overloading limits. The load and production ratings are larger than in the real network because with the real values congestions, naturally, do not occur. Using the composed 24-hour load and production profiles, the tertiary controller detects a congestion during two different hours (12 p.m. and 22 p.m.). These hours with congestions are used to test the tertiary controller operation.

6.1.1 Network reconfiguration: At time 22 p.m., the first section of feeder 1 between nodes PS0023 and 545 is loaded at 102.5% of its nominal capacity. The tertiary control invokes NR algorithm that shifts part of the load of feeder 1 to feeder 2 by opening the breaker 468-827 and closing the breaker 603-117.

Fig. 5 shows the branch loading using the original switching state and with the new topology calculated by the NR algorithm. After the NR operation, all line loadings are below 90% of the nominal rating and all node voltages are at an acceptable level. The losses of the study network have been increased by 5%.

6.1.2 Market agent: At time 12 p.m., a line section at the beginning of feeder 3 between nodes PL2 and 1056 is loaded at 104.24% of its nominal capacity. Also this congestion could have been solved by the NR algorithm, but its operation was suppressed to be able to demonstrate also the operation of the MA algorithm.

The MA utilises flexibility services to solve the congestion. In the study case, the sources of flexibility are heating and cooling devices, the electrical appliances and other sources of flexibility coming from industrial processes of non-domestic customers in LV and MV. The assumed decomposition into flexible and non-flexible demand for each load type is given in Table 1.

It is assumed that the aggregator collects the flexibility from its customers and aggregates it by type of customer (domestic, non-domestic and MV). Since no real flexibility bids were

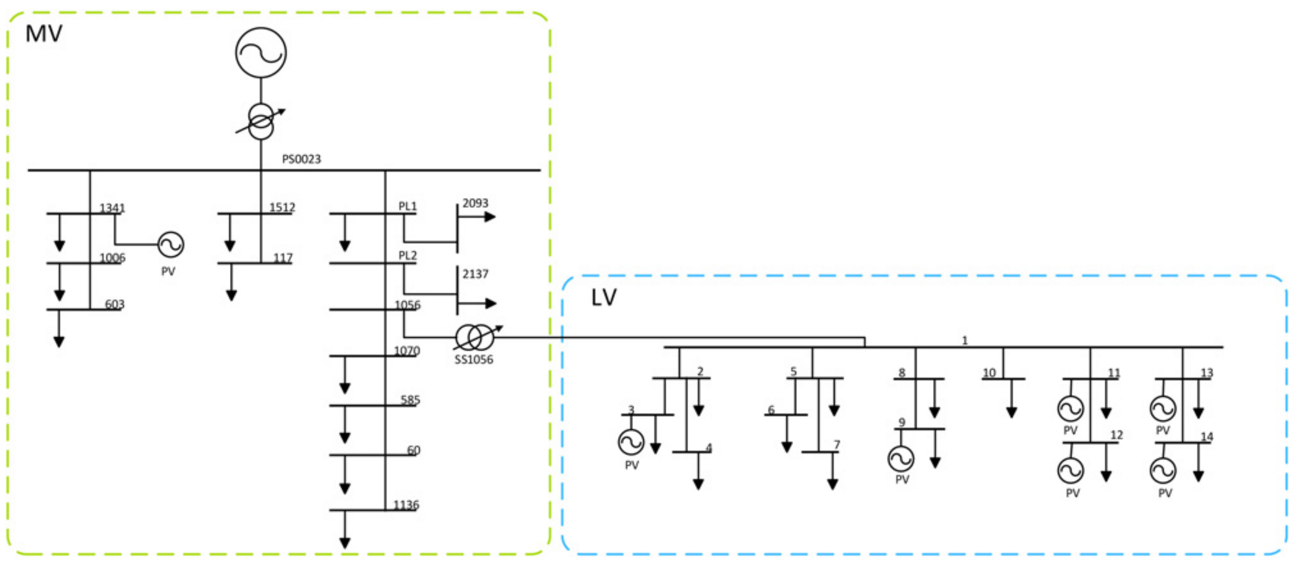

Fig. 7 *Network model used in RTDS simulations*

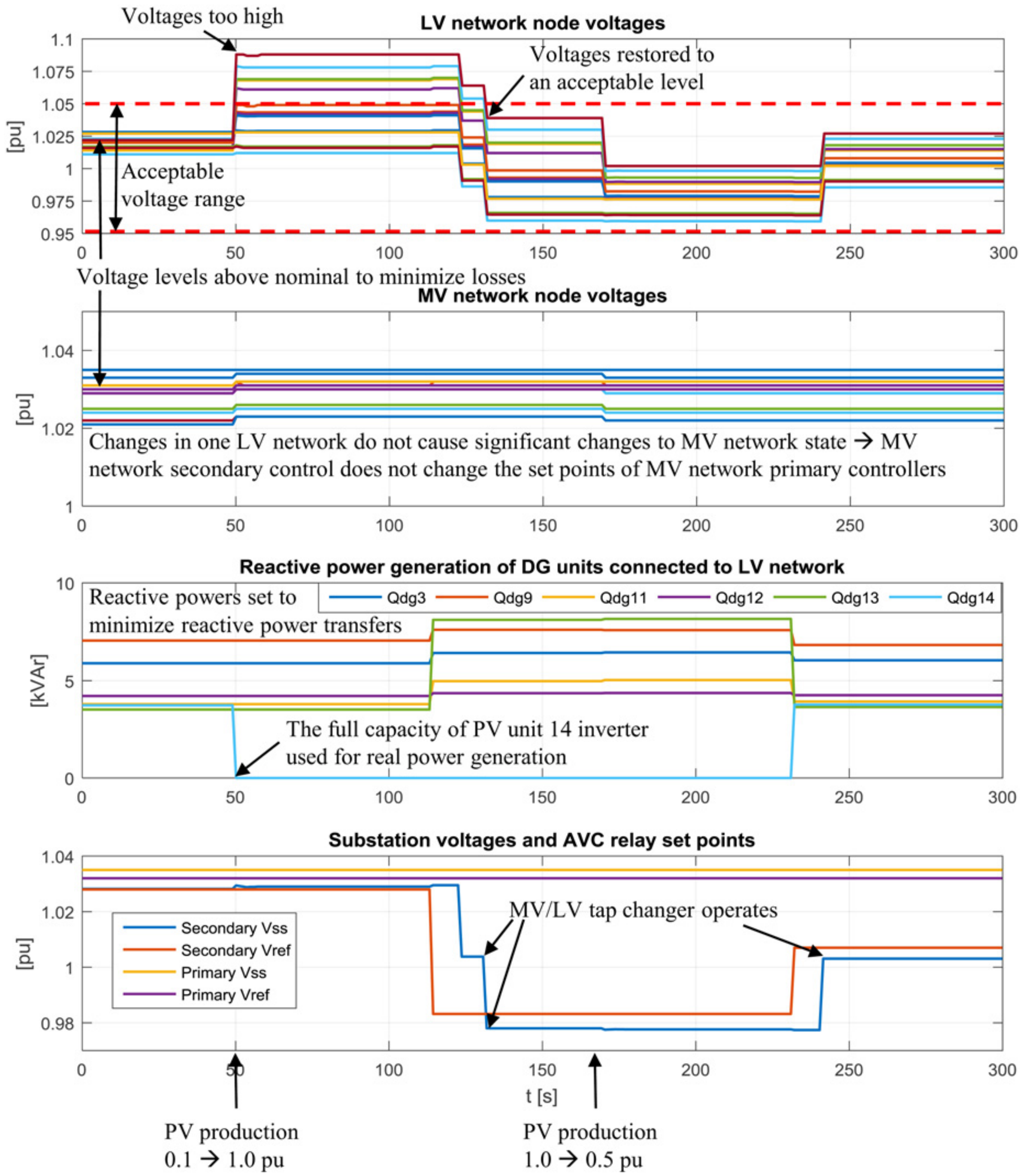

Fig. 8 *Real-time simulation results of the secondary control. Generated reactive power of the DG unit connected to the MV network is not represented in the figure to have proper scaling for the LV network connected units. Reactive power of the MV network connected DG unit remains constant 52,15 kVAr throughout the whole simulation time*

available, flexibility bids have been built from information of Table 1 and electricity prices by type of customer taken from EUROSTAT database [35], using data from the second semester of 2015. The average base price (price without taxes and levies) in Italy for medium standard industrial consumers (with an annual electricity consumption between 500 and 2000 MWh) is about 0.09 €/kWh, and the average base price for household consumers (with annual electricity consumption between 2500 and 5000 kWh) is about 0.15 €/kWh. Hence, flexibility bids have been built applying the prices shown in Table 2. In the study, the single national price in Italy (Prezzo Unico Nazionale, PUN) in 2015 has been used as the wholesale electricity market price. The average value of PUN in 2015 was 0.052 €/kWh.

In the example case, the total amount of flexibility needed is 221.3 kW and is distributed among different nodes on feeder 3 as indicated in Table 3. The total cost of the purchased flexibility is 25.13 €/h.

The loading of each network branch before and after applying the MA is shown in Fig. 6. The MA is able to solve the congestion, but the originally overloaded line section remains loaded at 100%. By applying security factors and purchasing more flexibility the final loading can be further decreased.

6.2 Secondary control results

The operation of the tertiary control was demonstrated using load flow simulations which is an adequate method to demonstrate its operation since also in reality it is operating based on hourly load and production forecasts. The secondary control operates in

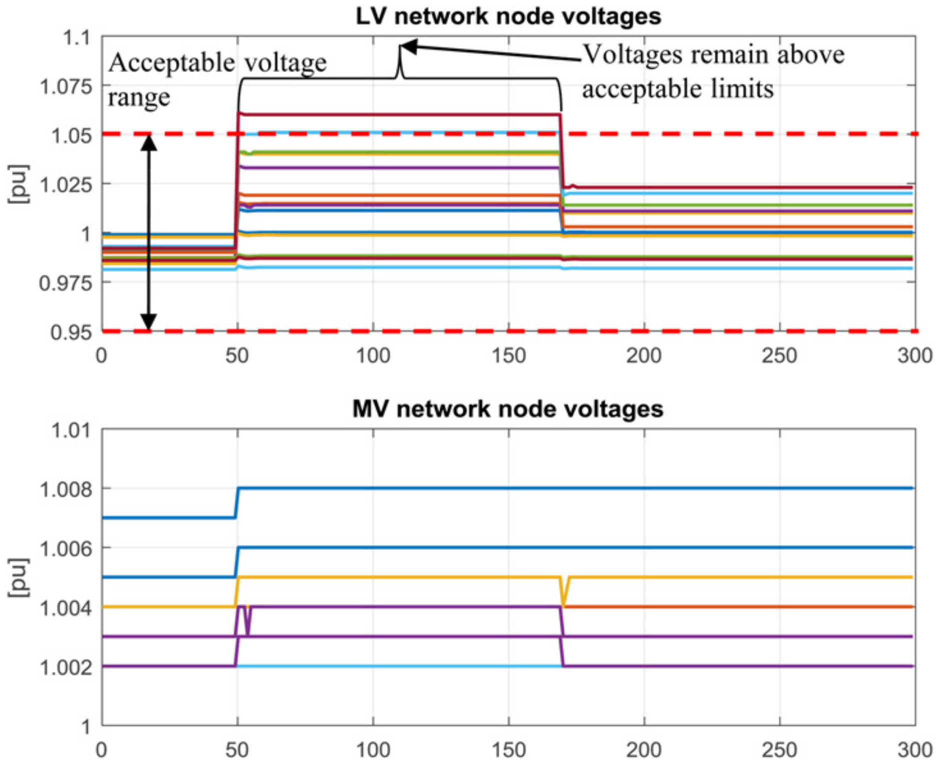

Fig. 9 *Network voltages without secondary control. AVC relays operate with constant voltage set point of 1.0 pu and the PV units are operated with unity power factor*

real-time and, therefore, time domain simulations are required to demonstrate its operation properly. The secondary control simulations have been conducted in the Real Time Digital Simulator (RTDS) laboratory of Tampere University of Technology. Real implementations of PSAU and SSAU including interfaces, database and state estimation and secondary power control functionalities are used in the simulations.

The model of Unareti network has been reduced to 15 MV network nodes and 14 LV nodes due to the node limitations of RTDS (see Fig. 7). The controllable resources at the MV network include the HV/MV transformer OLTC and real and reactive power of the PV unit depicted in Fig. 7. The controllable resources at the LV network include the MV/LV transformer OLTC (not present in the real Unareti network) and real and reactive powers of the 6 PV units (size increased compared with the real Unareti network) depicted in Fig. 7. The cost parameters of the optimisation algorithm objective functions are set to minimise only losses and curtailed generation and the cost parameter for generation curtailment is larger than the cost parameter for losses.

According to the measurement data from the DSO, the maximum PV production in the area occurs between 10 a.m. and 1 p.m. and the minimum loading during this time period occurs at 10 a.m. Therefore, 10 a.m. is selected as the simulation hour to be able to demonstrate the operation of the secondary control in case of voltage rise problems. Tertiary controller did not observe any congestions in the MV network at this time and the switching state calculated by the tertiary controller is the one depicted in Fig. 4.

The example simulation shows the operation of the real-time power control both in the MV and in the LV networks at the selected simulation hour. The load and production in the MV network differ somewhat from the forecasted values used by the tertiary controller, but the situation remains such that no MV network congestions appear. In the simulation sequence, step-wise changes in the PV production in the LV network occur. The time domain operation of the real-time power control algorithms both in the MV and in the LV networks is depicted in Fig. 8. The algorithms have been configured to be executed once a minute such that the LV network algorithm is started at the beginning of each minute and the MV network algorithm 30 s after the start of each minute.

Fig. 8 shows that the proposed secondary control algorithm is able to restore network voltages in all the simulated production conditions after a delay consisting of the time to wait for the next execution round of the algorithm, i.e. the start of the minute, the state estimation execution time, the power control execution time, the delay caused by the data transfer between the SAU and the RTDS and the AVC relay delay (8 s in the example case). Network voltages without the secondary control are presented in Fig. 9. When secondary control is not used, the network voltage can remain at an unacceptably high level until a further change in the production occurs which is not acceptable.

7 Conclusions

The control principles of distribution networks need to be altered when large-scale DG and other DER is connected to MV and LV networks. In this paper, a distributed control architecture and hierarchical congestion management concept for the future distribution networks has been presented. The proposed control concept enables scalable active network management utilising existing control centre software and distribution automation in an innovative way. Hence, there is no need to totally rebuild the distribution automation which makes the proposed solution applicable also in practice. The proposed concept integrates flexibility market to real-time automation of distribution network. Conflicts of interests between DSO and other market participants have been considered and therefore acceptance from all market participants is guaranteed. The control architecture is scalable, modular and enables easy addition of new DERs to the system. This paper presents both the proposed control concept and simulation results that validate its operation.

8 Acknowledgments

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Avoiding Adverse Interactions between Transformer Tap Changer Control and Local Reactive Power Control of Distributed Generators

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***Abstract*—Local reactive power control of distributed generators (DG) can be used to mitigate the voltage rise effect caused by themselves. In this paper, dynamic interactions between local voltage controllers of the DG units and transformer on load tap changers (OLTCs) are studied using time domain simulations. Studies are conducted with different control modes of DG unit and OLTC control and also secondary substation tap changers are considered. Several types of adverse interactions are identified in the simulations: unnecessary OLTC operations can occur, reactive power transfers can unnecessarily increase and consecutive tap changer operations can occur in case of cascaded OLTCs. The paper gives also some general planning guidelines to avoid the adverse interactions identified in the simulations.**

***Index Terms*-- Cascaded tap changers, Distributed generation, Distribution network dynamics, Decentralized control, Voltage control**

I. INTRODUCTION

Distributed generation (DG) can cause voltage rise problems in the existing distribution networks and local reactive power control of the DG units is one of the measures that can be taken to mitigate the voltage rise. In many countries (e.g. in Germany [1]), local reactive power control is a requirement for DG network interconnection. When DG reactive power control is taken into use, distribution network voltage is no longer controlled only by the primary substation on load tap changer (OLTC) and dynamic interactions between the different local voltage controllers will occur. Some studies on these dynamic interactions have been previously conducted and also adverse interactions have been reported. The number of tap changer operations can increase, the reactive power flows can increase and in some cases DG local reactive power control can in fact worsen the network voltage profile [2], [3].

In this paper, the adverse interactions between OLTC and DG voltage controllers are further studied. In the previous studies, a tap changer was available only at the primary substation. Installing tap changers also to secondary substations has, however, been suggested [4] and MV/LV transformers with tap changers already exist. This paper considers besides the HV/MV OLTCs the MV/LV OLTCs and voltage controllers of generators. This paper also deepens the analysis on the reasons for the different types of adverse interactions and gives general guidelines to prevent them.

II. STUDY METHOD

Time domain simulations conducted using PSCAD transient simulation program are used to study the interactions between OLTC and DG unit local controllers in distribution networks. Simulations have been conducted using two different network models having adjustable network parameters. Different control modes and parameters of the local controllers are used in the simulations.

A. Network models

The structure of the two simulation networks is presented in Fig. 1. In the first simulation case the DG units are connected to the MV network and the main aim is to study the interactions between the primary substation OLTC and the DG units. Also the operation of MV/LV tap changers is examined but their effect on the controller interactions is small as they can affect the operation of other controllers only through changing the voltage-dependent loads connected to their secondary. In the second simulation case the DG units are connected to the LV networks and the main aim is to study the interactions between the OLTCs both on primary and secondary substations and the DG units. If the MV/LV tap changers are not used, the studies do not significantly differ from the studies using the first simulation case.

In both simulation networks, the distribution lines are modeled using a π-connection and the lengths of feeders can be varied. Load type can be set to constant impedance, constant current or constant power. The primary substation HV/MV transformer always contains a tap changer and in part

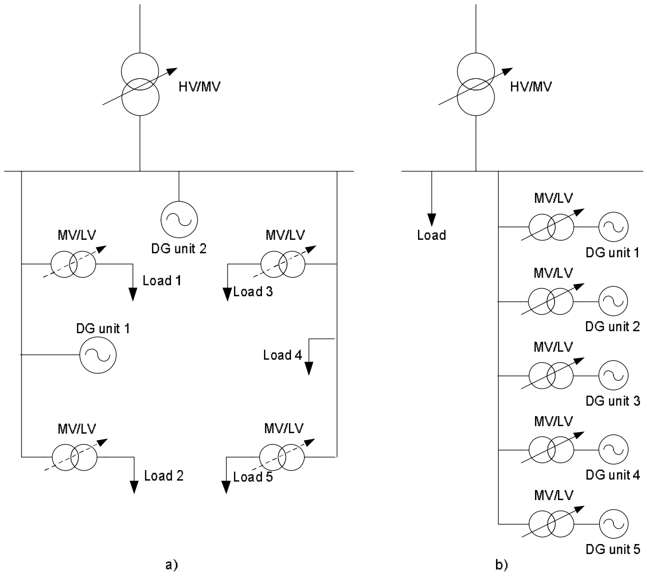

Figure 1. The structure of a) the first and b) the second simulation network.

of the simulations tap changer is available also at the secondary substation MV/LV transformers. HV network voltage can also be changed. Parameters of network components are similar in both simulation cases and are presented in Table 1.

TABLE I. NETWORK PARAMETERS ARE BASED ON PARAMETERS OF REAL NETWORK COMPONENTS.

HV network	S_k = 1 GVA, R/X=1/6
MV line	R = 0.281 Ω/km, X = 0.344 Ω/km, B = 3.46 μS/km, lengths varied
HV/MV transformer	110 kV/30 kV, 32 MVA, Ux=11.09 %, Ur= 0.41 %, tap step = 1.67 %, 25 tap positions (±12), mechanical tap delay = 2 s
MV/LV transformer	30 kV/0.4 kV, 1 MVA, Ux=4.97 %, Ur= 0.5 %, tap step = 2 %, 7 tap positions (±3), mechanical tap delay = 2 s

The network models include a time domain model of the automatic voltage control (AVC) relays that control the transformer tap changers [5]. The AVC relay measures the substation voltage and compares it with its reference voltage U_{ref}. If the measured voltage U_{meas} differs more than the AVC relay dead band *DB* from the reference voltage, a delay counter is started. This counter remains active as long as the measured voltage is outside the hysteresis limits of the relay and a tap change operation is initiated when the counter reaches the delay setting value. The delay can be constant or dependent on the voltage difference between the measured and the reference voltages. In this paper, inverse time characteristic is used and the delay T_d is

$$T_d = T_{d0}\frac{DB}{|U_{ref}-U_{meas}|}, \quad (1)$$

where T_{d0} is the delay set to the relay [5]-[6]. In case of cascaded OLTCs, time grading is used to coordinate the time domain operation of them i.e. MV/LV transformer AVC relays have larger delays than HV/MV transformer AVC relays [7]. Both constant voltage mode and line-drop compensation (LDC) mode are considered in this paper. In LDC mode the substation voltage is not kept constant but depends on the current flowing through the transformer. The substation voltage is increased at high transformer load and decreased at low transformer load. [5]

The DG units are modeled in PSCAD using a current source model. Three reactive power control modes of DG units are used in the simulations: constant power factor, $\cos\varphi(P)$ and $Q(U)$ as mentioned in [1]. In constant power factor and $\cos\varphi(P)$ control modes, the reactive power set point of the inverter depends on the measured real power and in the $Q(U)$ control mode on the measured voltage at the connection point. The characteristics of the $\cos\varphi(P)$ and $Q(U)$ control modes are represented in Fig. 2. The inverter dynamics related to the reactive current controller are represented using a first order transfer function

$$H_{inv} = \frac{1}{1+\tau_{inv}s}, \quad (2)$$

where the time constant τ_{inv} can be adjusted [8].

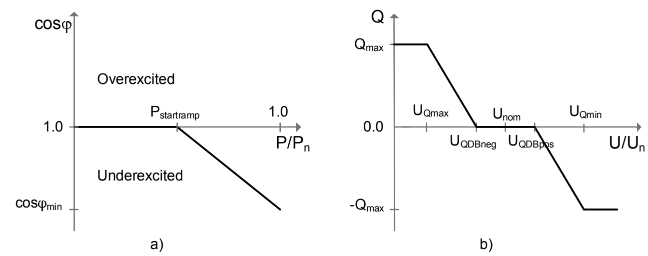

Figure 2. Characteristic of the a) $\cos\varphi(P)$ and b) $Q(U)$ control mode [1].

Two types of disturbances are used in the simulations presented in this paper to initiate control actions: DG real power changes and HV network voltage changes. In the former case, the DG unit reactive power control reacts to the disturbance in all control modes whereas, in the latter case, only the DG units in $Q(U)$ control mode react. Also simulations with loading changes were conducted but the results are quite similar to the results in case of HV network voltage changes and are not presented in the paper.

B. Control performance evaluation

The main aim of distribution network voltage control is to keep network voltage quality acceptable [9]. This objective should be achieved utilizing the available control resources cost-effectively. The following issues need to be addressed when the performance of the combined controller operation is evaluated.

- The voltage quality has to be always acceptable and the control operation stable.
- The tap changers should be used only when they are really needed. Tap changer operations cause wear of the tap changer and can increase its maintenance need which increases the costs of the distribution system operator (DSO).

- Reactive power control should not unnecessarily increase losses. Losses increase when the reactive power flow in the network increases. In most distribution networks, the losses increase when the DG units consume reactive power and, hence, reactive power consumption should be used only when it is really needed. There are, however, also networks where for instance lightly loaded cables produce reactive power and DG unit's reactive power consumption can help to decrease the losses [10].

- Reactive power control should not unnecessarily increase the reactive power fees paid by the DSO to the transmission system operator (TSO). In Finland, the reactive power flow between the distribution and transmission networks has to be kept inside a reactive power window determined by the Finnish TSO Fingrid [11]. In [12], the authors report of large reactive power fees which motivate the installation of compensation equipment. With the publication of the Demand Connection Code [13], the technical framework for the requirements on the reactive power exchange between transmission and distribution networks will be specified and harmonized.

The first bullet is critical and its terms need to be fulfilled always. The following ones describe the desired operation of the control system but the distribution network operation is not compromised if they are not always complied with.

III. Identified Adverse Interactions

A. DG reactive power control causes unnecessary OLTC operation

When some simplifying assumptions are made, the voltage change ΔU caused by a DG unit can be calculated as follows:

$$\Delta U = \frac{RP+XQ}{U_N}, \tag{3}$$

where R and X are the network resistance and reactance seen by the DG unit, P and Q are the real and reactive powers of the DG unit and U_N is the nominal voltage. Because the R/X-ratio of distribution feeders is not negligibly small, DG real power production causes voltage rise in the network. This voltage rise can be mitigated by DG reactive power consumption.

On the other hand, the R/X-ratio upwards from the primary substation is quite small and the transformer has also an almost purely inductive reactance which is non-neglibigle. Hence, the combined effect of the DG real and reactive powers is not similar on distribution network feeders and on the primary substation. It is possible that the voltage at the DG connection point on the feeder increases but the voltage at the substation decreases at the same time due to the different R/X-ratios. This difference in the R/X-ratios leads to adverse interactions between the OLTC and DG unit voltage controllers in certain situations.

Fig. 3 shows example simulation results in the first simulation network where the DG units operate in $\cos\varphi(P)$ control mode with the parameters P_{start} = 0.5 p.u. and $\cos\varphi_{min}$ = 0.8 (see Fig. 2) and the nominal power of both DG units is 10 MVA. The primary substation AVC relay is operating in constant voltage mode with a reference voltage of 1.0 p.u.. The dead band is ±1 % and the delay of inverse time operation T_{d0} is 30 s. DG unit 1 is located 30 km from the substation and DG unit 2 1 km from the substation. Changes in the real power of the DG units are used as disturbances. Fig. 4 presents simulation results using the same simulation sequence but with the DG units operating in $Q(U)$ control mode. The dead band U_{QDBneg} – U_{QDBpos} is 0.99-1.01 p.u., U_{Qmax} is 0.96 p.u., U_{Qmin} 1.04 p.u. and Q_{max} 0.75 p.u. (see Fig. 2). The inverter time constant is in both cases 1 s.

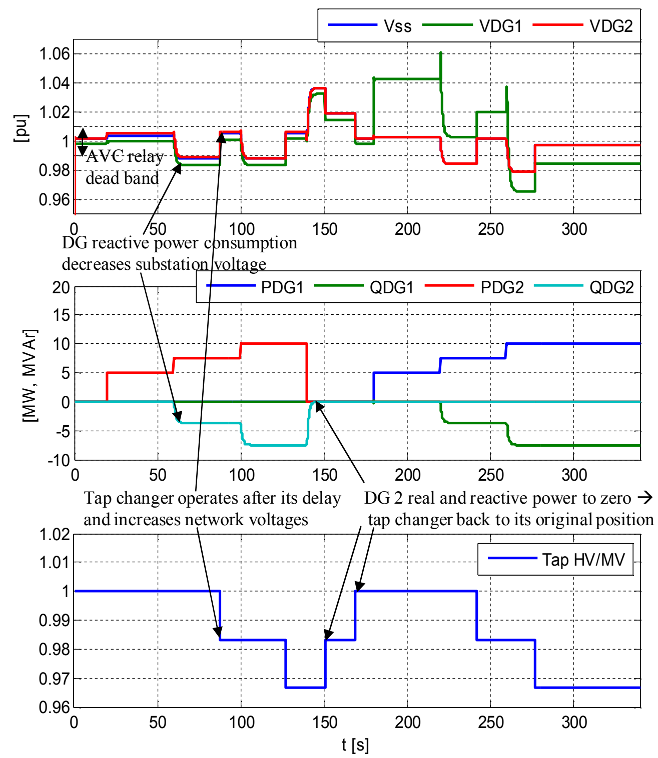

Figure 3. Unnecessary tap changer operations when the DG units operate in $\cos\varphi(P)$ control . The uppermost figure presents the substation voltage V_{ss} and the terminal voltages of the two DG units. The second figure presents the real and reactive powers of the two DG units and the lowest figure includes the HV/MV-transformer tap position.

Unnecessary tap changer operations can be seen both in Fig. 3 and in Fig. 4. The mechanism that causes these tap changer operations is the same in both cases: The DG units consume reactive power based on their control characteristics that are required to mitigate the distribution network voltage rise caused by the DG units. The reactive power, however, affects the voltage at the substation and at the DG connection point differently. The R/X-ratio upwards from the primary substation is usually relatively small and, therefore, the substation voltage often decreases although the feeder voltages can be larger than without the DG unit. If the substation voltage decreases below the AVC relay dead band limit, the tap changer operates to increase the network voltages. Hence, there is an interaction between the two local controllers where the DG reactive power controller aims to decrease DG connection point voltage and the AVC relay opposes this control action by increasing the network voltages.

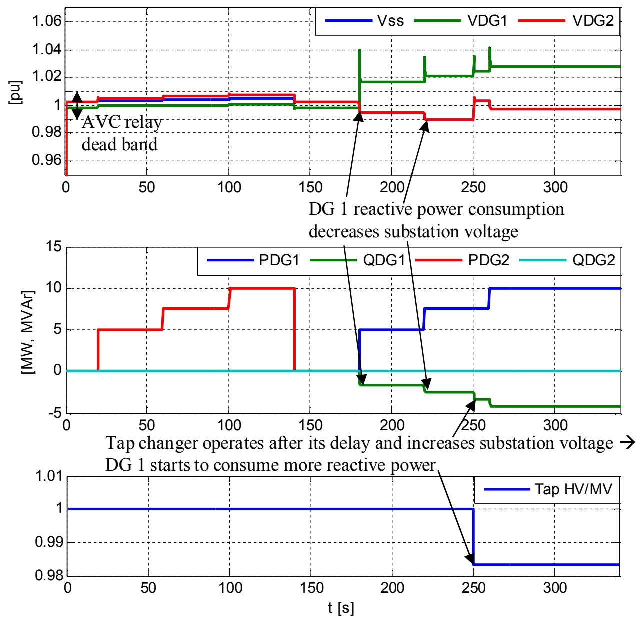

Figure 4. Unnecessary tap changer operations when the DG units operate in *Q*(*U*)-control mode.

The number of unnecessary tap changer operations is different depending on the control mode. In *cosφ*(*P*) control mode the reactive power output of the generators is dependent only on the real power output of the units. The location of the DG unit does not affect its reactive power output and the reactive power outputs of DG units 1 and 2 are equal in Fig. 3. When the real power of either of the DG units is increased from zero to the nominal power, two tap changer actions are initiated. It should be noted that when *cosφ*(*P*) control mode is used, reactive power is consumed also when it would not be necessary. DG unit 2 is located close to the substation and its real power production does not affect network voltages significantly. The reactive power consumption, however, does have an effect on the voltages because the *R/X*-ratio seen by the DG unit is relatively small and several unnecessary control actions are performed.

When the DG units operate in *Q(U)* control mode, reactive power is consumed only if the terminal voltage of the DG unit increases enough. As DG unit 2 is located close to the substation, its real power production is not able to increase the terminal voltage significantly and reactive power is not consumed. DG unit 1 is located farther away from the substation and real power production increases the feeder voltages. Reactive power is consumed to mitigate the voltage rise. On the feeder, the voltage level remains higher than without the DG unit but at the substation the voltage decreases and the tap changer operates to increase the substation voltage. This change in substation voltage increases also the DG unit connection point voltage and the reactive power consumption increases based on the control characteristics.

The same simulation sequence was run also using constant power factor control. In the case of unity power factor, the real power changes alone are not able to change the substation voltage substantially and, hence, additional tap changer actions do not occur in the example case. DG 1 connection point voltage, however, increases to 1.08 p.u. at nominal DG power. In this case, the MV feeder voltage limits are set to 0.95-1.05 p.u. and, therefore, the unity power factor operation is not acceptable. The cases with constant inductive power factor are quite similar to cos*φ*(*P*) control case.

The example cases shown in Fig. 3 and Fig. 4 were selected such that the adverse interactions would be easily visible. The DG units are large and have relatively large reactive power capability. Simulations have been conducted also in several other cases. Unnecessary tap changer operations are possible in all control modes that use reactive power consumption to mitigate the voltage rise caused by the DG units. In the simulations, the probability of unnecessary tap changer operations increases when the nominal power and/or reactive power capability of the DG units is increased. In case of cos*φ*(*P*) control, the location of the DG unit does not change its effect on tap changer operation but in case of *Q*(*U*) control the amount of consumed reactive power increases when the DG unit is located farther away from the substation and, hence, also unnecessary tap changer operations can be seen more often. If the dead band in the *Q*(*U*) control is decreased, DG units closer to the substation will start to cause unnecessary tap changer operations and vice versa. Also the original HV voltage level affects the simulation results. If the transformer secondary side voltage is already near the dead band limit at the start of the simulation, even small changes in DG unit powers can lead to tap changer operations whereas if the voltage is at the center, relatively large changes are needed to cause a tap changer operation.

The control mode and parameters of the substation AVC relay affect the results significantly. In the simulation results of Fig. 3 and Fig. 4, the AVC relay is operating in constant voltage mode. If the AVC relay is operated in LDC mode and the parameters are properly selected, the unnecessary tap changer operations can be prevented because the substation voltage set point is decreased when the transformer loading decreases due to increase in production. This is a suitable choice if all network voltages remain at an acceptable level in all possible loading and production conditions also with the LDC. If the effect of DG has not, however, been taken into account when selecting the LDC parameters, it is possible that a production increase on one feeder causes too low voltages in some adjacent pure load feeder [14].

The operation of the MV/LV-transformer OLTCs is shown in Fig. 5 in the case where DG unit 1 operates at constant power factor of 0.9. The real power output the DG unit is increased from zero to 5 MW at time 20 s. The DG unit is located 30 km from the substation, load 1 15 km from the substation and load 2 1 km after the DG unit. At the adjacent feeder, load 3 and 5 are located 1 and 12 km from the substation, respectively. All the AVC relays are operating in constant voltage mode and the dead bands are set to ±1 % in the HV/MV-transformer and to ±1.2 % in the MV/LV-transformers (1.2*tap step). The delay of inverse time operation T_{d0} is 30 s in the HV/MV OLTC and 60 s in the MV/LV OLTCs. In this example case, the unnecessary tap changer action in the primary substation leads to tapping of all the MV/LV-transformers on the DG feeder to the opposite direction. These tap changer operations are advantageous from

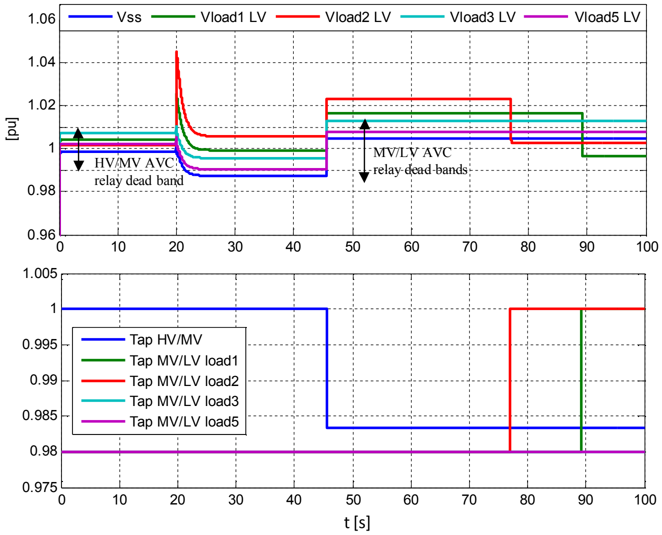

Figure 5. Unnecessary primary substation operation causes secondary substation tap changer operations. The upper figure contains the transformer secondary voltages used in AVC relay control and the lower figure the tap positions. DG 1 real power increases from 0 MW to 5 MW at time 20 s.

the customer voltage point of view but the number of tap changer operations can become large which increases the tap changer maintenance costs. A large number of secondary substation OLTC operations can occur also in cases where the unnecessary primary substation OLTC operations are prevented by using the primary substation AVC relay in LDC mode. In this case, DG real power production decreases the primary substation voltage and, hence, also voltages on all feeders that do not include DG. If these feeders include MV/LV OLTCs, they will operate to keep the LV side voltage within their control limits introducing a large amount of tap changer operations.

B. DG reactive power flow increases unnecessarily

DG units operating in $Q(U)$ control mode respond also to network voltage changes originating from other sources than the DG unit itself (changes in HV network voltage, loading changes etc.). If the voltage controllers of the DG units are faster than the OLTC controller, it is possible that the DG units start consuming or producing a large amount of reactive power and prevent the operation of the OLTC in situations where OLTC operation would be the preferred control operation. In Fig. 6 one such example case is represented. DG unit 1 is producing its nominal power 10 MW and operates in $Q(U)$ control mode with the same parameters as in Fig. 4. The DG reactive power control is significantly faster than the OLTC control (inverter time constant is 1 s and the AVC relay delay of inverse time operation T_{d0} is 30 s). When the HV voltage increases, the DG unit starts to consume more reactive power and the substation voltage re-enters the AVC relay band and the tap changer does not operate. The reactive power transfer in the network remains higher than before the change in the HV network voltage. This kind of operation can occur when the $Q(U)$ control is operating at the droop part of its control characteristic and is more pronounced if the DG unit is located closer to the substation. On the other hand, DG units located close to the substation operate usually in the dead band area of their control characteristic if the parameters have been properly selected.

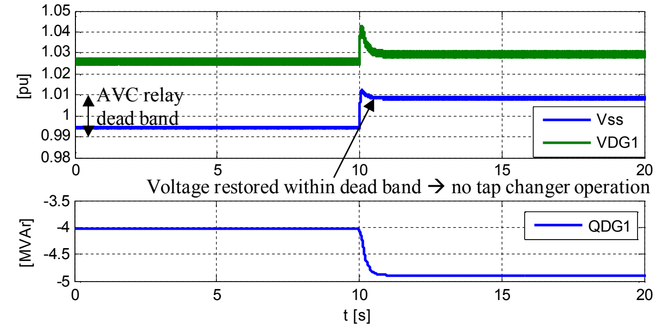

Figure 6. DG reactive power control prevents OLTC operation. The HV voltage increases at time 10 s.

C. Secondary substation OLTC operations cause operation of the primary substation OLTC

In the second simulation case, the DG units are connected to LV networks and there are OLTCs on the MV/LV – transformers. If the reactive power of the DG units does not depend on the measured voltage i.e. they are operated in constant power factor or $\cos\varphi(P)$ mode, the interactions between controllers are similar to the ones presented in section III.A. If the DG units are, however, operated in $Q(U)$ control mode, new type of interaction is introduced. When the MV/LV OLTC operates and the LV network connected DG units are used in $Q(U)$ control mode, the voltages at the primary and secondary substations change in opposite directions. If the MV/LV OLTCs increase their secondary side voltages, the DG units increase their reactive power consumption and, hence, the primary substation voltage decreases. This can induce an HV/MV OLTC operation. This interaction is illustrated in Fig. 7. No dead band is used in

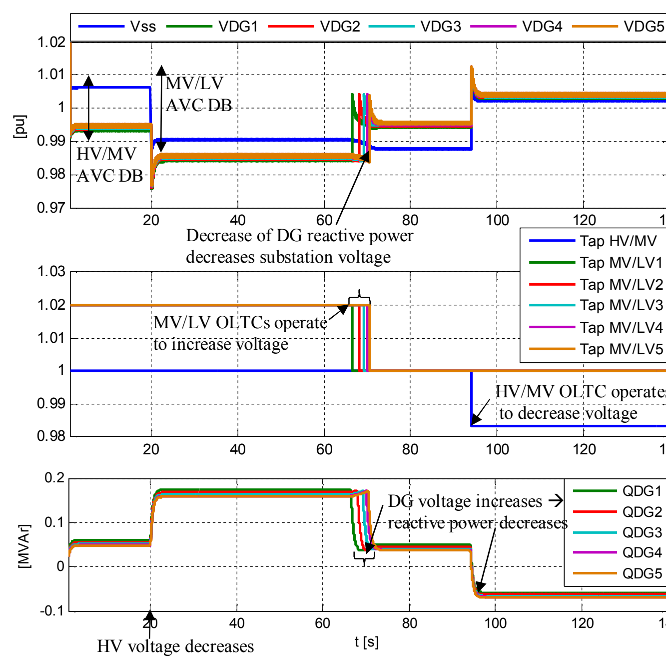

Figure 7. MV/LV OLTC operations cause HV/MV OLTC operation.

$Q(U)$ control and U_{Qmax} is 0.96 pu, U_{Qmin} 1.04 pu and Q_{max} 0.5 p.u.. All feeder lengths are set to 1 km.

Several simulations were conducted to determine whether tap changer hunting could be possible due to the opposite voltage change in primary and secondary substation after MV/LV OLTC operation. Unstable operation was not visible in any of the simulations even when the control system parameters were purposely poorly selected trying to invoke hunting. With unrealistic controller parameters it was possible to invoke three tap changer operation steps i.e. one additional operation of all MV/LV OLTCs occurred after the HV/MV OLTC operation of Fig. 7 but after that the system stabilized.

IV. Preventing the Adverse Interactions

If only local controllers are utilized, it is not possible to avoid all unnecessary control actions presented in the previous chapter. Proper selection of control modes and control parameters can, however, decrease the number of unnecessary control actions substantially.

Unity power factor control is usually the most advisable option if reactive power control is not needed either to mitigate the voltage rise caused by the DG unit or to control the reactive power transfer between the distribution and transmission systems. If the DG unit is connected near the substation it does not cause a significant voltage rise. If the DG unit is connected on a dedicated feeder, the magnitude of the supply voltage is not determined by the standard EN 50160 [9] and can, hence, be agreed to a suitable value. DG reactive power control is not needed for distribution network voltage control purposes in either case. If reactive power control is in these cases needed to keep the reactive power transfer between the distribution and transmission systems at an acceptable level, constant power factor or constant reactive power control mode should be used.

Reactive power control should, naturally, be used if it is needed for distribution network voltage control. Selecting the control mode is not, however, obvious. The number of unnecessary tap changer operations due to changes in DG unit real power is larger when constant power factor or $\cos\varphi(P)$ control is used compared to $Q(U)$ control. Therefore, the wear of the tap changer is larger using those control modes. On the other hand, the interactions introduced in sections III.B and III.C are possible only if the DG units operate in $Q(U)$ control mode. Moreover, if the parameters of the $Q(U)$ control are not properly selected, the local control can become unstable [8].

In $Q(U)$ control, using a dead band is advisable. Suitably selected dead band decreases the probability for large reactive power transfers (section III.B) and consecutive MV/LV and HV/MV OLTC operations (section III.C). Also the number of unnecessary primary substation OLTC operations (section III.A) is smaller when a dead band is used. Also, the droop should not be too steep to guarantee stability of the local control and to decrease the probability for the aforementioned adverse interactions.

The dead band of the AVC relays should be also properly selected. If it is too small, the number of unnecessary OLTC operations increases and the interaction presented in section III.C will be seen more often. If it is too large, the voltage quality of the network can be worsened and it is more probable that large reactive power flows will replace the tap changer operations (section III.B). Unnecessary OLTC operations can, in some cases, be prevented by using the AVC relay in LDC mode but it has to be made sure that the network voltage quality is secured, meaning that the LDC parameters must be tuned to the individual network situation.

V. Conclusions

Three types of adverse interactions between local transformer tap changer control and local reactive power control of distributed generators have been identified and simulated in this paper. In addition to introducing the adverse interactions, the paper also discusses the reasons for them and provides general guidelines for selecting the control modes and parameters of voltage controllers properly.

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Real-time distributed monitoring and control system of MV and LV distribution network with large-scale distributed energy resources

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Abstract--**The aim of the paper is to provide a holistic overview of Active Network Management utilizing hierarchical decentralized distribution automation and flexibility services from Commercial Aggregators. Interactions of Commercial Aggregators, Distribution System Operator and different markets will be explained at European market and regulatory regime. Descriptions of the real-time medium and low voltage grid monitoring and control use cases that characterize the proposed approach will be provided. The proposed distribution automation concept will be analyzed and discussed in the paper based on experiences of laboratory and field demonstration implementations. The proposed concepts and distribution automation will lead to significant improvement of network efficiency and increase in network hosting capacity.**

Index Terms—**Decentralized control, Distributed power generation, IEC standards, Monitoring, Power distribution, Power system management, Smart grids, Substation automation.**

I. Introduction

THE trend toward increasing the share of Renewable Energy Sources in the electricity system and to improving energy efficiency (e.g. electric vehicles and heat pumps) have put strains on the local distribution networks. The basic aims of Active Network Management (ANM) are to enhance the reliability and power quality of network and to increase the network hosting capacity for renewables. ANM is based on Distribution Automation (DA) and flexibility services of Distributed Energy Resources (DERs) like Distributed Generation (DG), demand response, storage and micro-grids. Secondly the concept of Commercial Aggregator (CA) offering flexibility services is integrated with ANM.

The objective of the paper is to show how the general concepts of ANM and CA may be implemented and what that requires from DA viewpoint. The aim of the paper is to provide a holistic overview for the concept, DA architecture and functionalities, and therefore many details are included in references. The paper reports experiences of demonstration project and therefore it is not a review of different proposals.

The Chapter II provides a holistic overview of ANM and flexibility services, and interactions of CAs, Distribution System Operator (DSO) and different markets. The automation system is described in Chapter III. The real-time Medium Voltage (MV) and Low Voltage (LV) grid monitoring and control use cases that characterize the proposed approach and the interference of use cases is described in Chapter IV. The analysis of proposed architecture and functionalities are evaluated in the Chapter V.

II. Concepts

A. Active Network Management

Electricity distribution networks have so far been designed and operated as passive networks according to a design point that requires them to handle all probable loading conditions to meet quality of supply obligations. This result into sub-optimized network efficiency because the full network capacity is utilized seldom. With that design point, the only way to increase the number of serviced DERs is adding network infrastructure assets in proportion. Firm connection capacity offered for DERs is always available but the infrastructure cost may become very high when the hosting capacity of existing network has exceeded.

The ANM integrates DERs into the grid management instead of connecting them to the network with the “fit and forget” principle. Controllability and flexibility of DERs is exploited to optimize network investments and operational costs. Synergy benefits may be achieved by coordinating the operation of DERs from the whole system viewpoint instead of optimizing their operation individually from a single party’s, like retailer, viewpoint. Retailer and DSO must be separate companies in European regulatory context.

The ANM may be enabled by several ways like grid codes, grid tariff schemes, bilateral control contracts, or market based flexibility services. The control of customer owned DERs may be realized by direct control (e.g. grid code or bilateral contract based on volume signals where control response is quite deterministic) or by indirect control (e.g. tariff schemes or market based flexibility services based on price signals

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where the control response is more stochastic compared to direct control). Non-firm connection contract between a customer and DSO is an example of bilateral contract, where DSO has chance to curtail production or shift controllable loads to off-peak periods. Grid code, which is determining connection rules for DERs, might be used to mandate control and communication capabilities for DERs (e.g. reactive power control capability of a DG unit which is available for DSO). Indirect control of DERs is based on flexibility services offered by CAs. Dynamic (e.g. time-of-use) or power based grid tariff incentives customers for load shifting and self-consumption of generated power.

Essential part of the implementation of ANM is DA and integration of it to other parties of electricity market and power system management. DA includes control centre information systems, substation automation, secondary substation automation and customer interface (e.g. smart meters). It realizes the real-time monitoring and controlling of the whole MV and LV networks, and direct control of DERs. Traditional DA solutions (e.g. centralized SCADA/DMS (Distribution Management System)) are not rapid and scalable enough to monitor and control large-scale DERs in real-time both MV and LV networks. Therefore novel hierarchical decentralized automation architecture is proposed for ANM. Integration of IT systems and coordination of control actions of CAs and DSO/TSO (Transmission System Operator) are essential for management of complete system.

B. Commercial Aggregator and interaction with DSO

As defined in [1] flexibility can be described as the modification of consumption patterns and generation injection in reaction to a price signal or activation request in order to provide a service within the energy system. The sole source of flexibility are prosumers – meaning consumers capable of producing their own energy – in the form of industrial, commercial and domestic providers [2].

Potential services to be provided by means of flexibility within the power system are traded in electricity markets. Given that most consumers and prosumers do not have nor the means nor the size to trade directly into wholesale electricity markets, they require the services of a CA to access them [3]. Main role of the CA will be therefore to gather flexibility from its consumers/prosumers portfolio and to optimize its trading in electricity markets aiming to maximize profits.

In order to ensure a transparent and equitable market design for flexibility aggregation, the role of CA towards other market parties (i.e. customers, Balance Responsible Parties (BRPs)/suppliers and TSOs/DSOs) should be clarified. CAs are entering several European electricity markets, some of them acting as third parties, contacting directly with customers for flexibility services and selling them in an aggregated manner on wholesale electricity or TSO's ancillary service markets [4]. In this context it should be ensured that BRPs/suppliers are compensated for the energy they inject and that is re-routed by these CAs acting as third parties – as it is already done in Switzerland, where clear rules on imbalances management have been recently settled [3]. For the future, the simplest scheme – as it is proposed here – is the one where BRP/suppliers act as CAs, making the chain of balance responsibility remain intact and delivers simple arrangements such as one main contact point for the customer [5].

To ensure safe, secure and cost-efficient distribution and transmission network operation and development, CAs will have to coordinate with DSOs and TSOs, that must also coordinate to each other and have access to flexibility services and all technical relevant data needed to perform their activities both at pre-qualification and operation stages.

From DSO perspective, flexibility should be integrated as part of ANM where new functionalities should be integrated aiming to realize the new roles of DSO: (i) flexibility procurer to feed DMS and its functions to hinder network congestion; and (ii) responsible for technical validation of distribution network located flexibility products coming from day-ahead and intra-day markets and technical validation before its activation when requested by third parties (TSOs, BRPs, etc.).

In relation to role (i), as described below the ANM will include a market agent functionality in charge of flexibility procurement on a day-ahead and intra-day basis, and activation of already procured conditional re-profiling products from CAs for addressing short-term grid contingencies when they become the most cost-effective measure. Flexibility services offered by CA to DSO could be for example active power flexibility for power flow management (by means of production curtailment, load shedding or demand shifting). Proper principles of coordination between DSOs and TSOs should be defined for validation of conditional re-profiling products when its activation could potentially affect the TSO network.

Regarding role (ii), in order to ensure DSOs having visibility of the planned aggregation actions connected to their networks, and ensuring that market schedules are not in conflict with network operation, the ANM will use its tertiary control system as described below for validation purposes both during the off-line time frame (at day-ahead and intra-day markets), and during real-time periods. In Fig. 1 the interaction among actors and its functionalities is depicted. As shown in the figure, a flexibility market where TSOs and DSOs can access to is proposed to avoid fragmentation of markets and ensuring effectiveness of system operation [6].

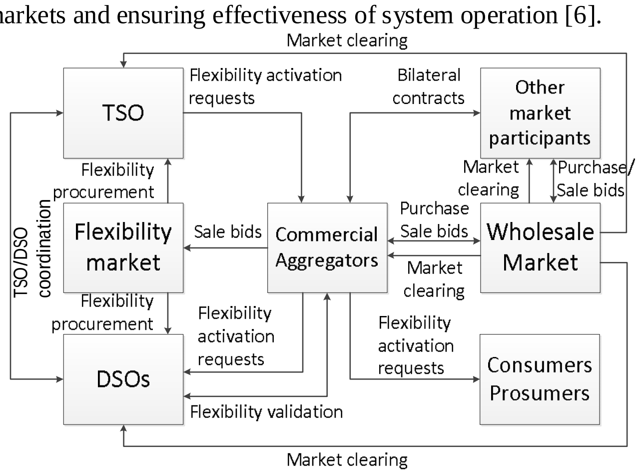

Fig. 1. Commercial aggregator market setup.

III. Automation System

Real-time monitoring must be extended from primary substations only, to secondary substations up to final customer where the Advanced Metering Infrastructure is present or underway in many countries. Power quality meters, fault recorders and Phasor Measurement Units are examples of new sources of measurements that are integrated in the DA.

The control of distribution grid, which is active at all voltage levels and equipped with pervasive monitoring, should be designed coherently: distributed, to use the measurements and estimates available locally, and coordinated to smoothly control over different time horizons and vertical locations within the distribution network, and to harmonize commercial and technical decisions. From the actuation standpoint, this requires Intelligent Electronic Devices (IEDs) as control units and Substation Automation Units (SAUs) to decentralize decision making and shift it from control centre to primary substations, secondary substations and DERs. [7]

A. *Schematic Model*

The high level, semantic model of the architecture and its domain (rectangles with solid line) is represented in Fig. 2 together with external parties (dashed boxes). Within the ANM, the DMS is the central control and monitoring arm of the DSO, realizing centralized and grid wide control decisions and interfacing with the CA via market operator. Other centralized systems like Automatic Metering Management (AMM), Customer Information System (CIS), Geographic Information System (GIS) and Network Information System (NIS) are integrated with DMS. CA interacts directly with the IEDs of the resources (e.g. home energy management systems) that the CA manages. DSO owned IEDs are installed in the substations and along MV feeders, and interact with the Substation Automation Unit (SAU), which is the brain and communication/data hub of the monitoring and control area. The Microgrid Central Controller (MGCC), which is itself a specialized instance of SAU, interacts with CA for commercial purposes and with DSO’s SAUs for technical purposes. SAU represents a general concept, where Primary and Secondary SAUs are instances of the same SAU concept. Also each block is represented by data (that it owns, and stores), interfaces (through which it interacts to get data or provide services through its functions; all this defined according to the standards), and functions they can host. [7,8].

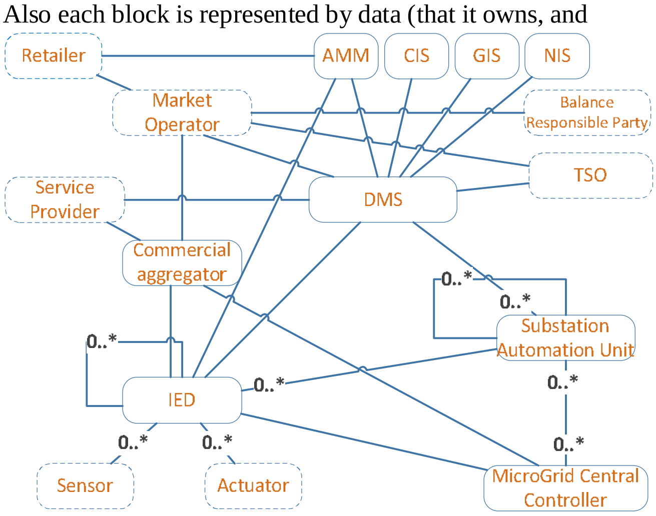

Fig. 2. Semantic model of automation system.

B. *Requirements for Automation System*

Scalability is a critical feature in DA, because of the large number of nodes, substations and DERs. Therefore the proposed architecture is distributed and modular. The monitoring system that supports this automation architecture is expected, within the next decade, to be able to handle millions of measurement points and a large volume of data. Therefore the architecture is based on a hierarchical structure where on-line and automatic handling and analysis of data is performed to reduce the amount of data transfer to control centre. Distributed data storage allows tracking every detail without real-time communication to control centre [9]. Same can be said for the functionalities like distributed Fault Location Isolation and Supply Restoration (FLISR) and power control, which are carried out in IEDs and SAUs, without resuming to the control centre.

The automation system should also be based on standards. From a design standpoint, this is needed to enhance and simplify the integration of subsystems, which is an essential requirement of DSOs. The IEC 61850 is now assuming the role of de-facto standard for the DA. Data acquisition and the interfaces between the SAU and the peripheral devices has been implemented using standard protocol such as DLMS/COSEM for smart meters and IEC 61850 MMS messages for IEDs. Quasi-static information such as the network topologies and network asset information is however encompassed by the CIM standard. [9,10]

IV. Monitoring and Control Use Cases

A. *Real-time Monitoring, Forecasting and Estimation*

The optimal control and high performance management of a grid requires knowledge of all network levels. For this reason the monitoring encompasses all network levels, aggregating and processing the collected information in a hierarchical and distributed structure with the aim to manage the complexity and the big amount of data.

In the monitoring system, SAU is in charge of collecting values, events and signals from its subnet to monitor the grid and reporting an aggregated view of network, after an internal elaboration phase, to the upper level. Measurement and static network data are stored in a local database with an increased granularity from the underlying grid to the control centre and it is maintained only where it is needed to perform forecasting, estimation and control algorithms locally. State estimation provides system quantities which are not directly measured and because real implementations of monitoring system are subject to errors in measurements, due to communication failures, corruption of the data or temporal unavailability of a meter. Load and production forecasting algorithms are needed to predict the state of the network few hours and day-ahead.

B. *Power Control*

Fig. 3 illustrates the hierarchy of the controllers and their

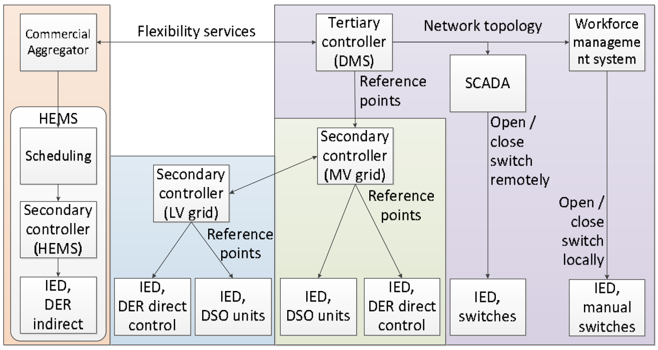

Fig. 3. Hierarchy of controllers. (colours are for visual clarity)

interactions. Primary controllers (IEDs) operate autonomously with fast response and the set points may be adjusted remotely. Secondary controller (SC) coordinates the operation of primary controllers within a control area. SCs are located at primary or secondary SAUs depending on which network, MV or LV grid, they are managing. Tertiary controller (TC) manages the whole system. It is located in DMS and it communicates with CAs via market operator to validate and to request flexibility services, and it adjusts network topology remotely via SCADA and workforce management system. It may also advise SCs from system and day-ahead viewpoints.

SC addressing power flow and voltage control may enhance the network hosting capacity for DERs compared to primary voltage control schemes [11]. SC is running in real-time and it is based on Optimal Power Flow (OPF) to define set points for primary controllers to minimize operational costs like losses, production curtailment and demand response.

TC manages the TSO-DSO interface and MV grid and it is running both day-ahead and real-time. TC is planning the optimal network topology (network reconfiguration) for the next day while considering boundary conditions between control areas and forecasted states of the network to prevent congestion. In addition TC takes responsibility to validate network acceptance for flexibility service actions within DSO's network, and to purchase flexibility services if needed to solve congestion. In real-time mode the TC is supporting FLISR functionality by acting as slow restoration functionality after fast FLISR in order to enlarge the restoration area. Further details about the design and implementation of SC and TC are given in [12].

C. *Interference of use cases*

The use cases are interdependent, in that they exchange data and take actions that other use cases have to cope with. As a consequence use case "interfere". The coordination of control use cases, from a conceptual viewpoint, is realized through a primary-secondary-tertiary scheme and control areas. The monitoring use cases interfere with control use cases by providing current and forecasted data. The way of interfere of these two groups of use cases defines most of the data exchange requirements in the architecture design.

Fig. 4 presents the detailed description of interferences between hierarchical levels of the control system and functioning of grid management in different time frames (day-ahead, intra-hour, and real-time). TC is indicated by dark blue colour and consists of grid tariff calculation, off-line validation (network reconfiguration and market agent), slow restoration (real-time implementation of network reconfiguration), and real-time validation. SC is indicated by light blue colour and consists of secondary power control, Block OLTC of Transformers and power control parameter update. Primary controllers are indicated by white colour. In addition to controllers figure includes supporting functionalities like forecasting (orange), monitoring/estimation (green) and market functionalities (purple).

Day-ahead hourly forecasts of load demand and production are fed in tariff calculation and off-line validation. Dynamic grid tariffs are published for all CAs to intensifying for load shifting from network peak to off-peak hours [12]. After the day-ahead market bidding process, DSO will validate if proposed schedules of all market parties for load demand and production will fit in local distribution network constraints. If congestion does not exist then market may be closed, otherwise the TC will try to mitigate congestion by reconfiguring the network or requesting help from market agent to seek for the cheapest solution by means of rejecting/activating Scheduled ReProfilings (SRPs) and/or Conditional ReProfilings (CRPs) from the market and/or from bilateral contracts. SRP services may be purchased from day-ahead energy market but also from other markets like intra-day or intra-hour markets. CRP is purchased from flexibility market for example organized by DSO in similar way as balancing power market by TSO.

Intra-hour time frame links day-ahead decisions to real-time frame. Power control parameter update functionality modifies the cost parameters of OPF within real-time SCs in order to adapt them to changes in forecasted network state and in MV network topology.

Real-time follows similar structure as previous time frames except real-time monitoring is utilized instead of forecasting. State estimation provides necessary inputs for the real-time SC. The State estimation utilizes in addition to real-time measurements customer specific load and production forecasts and customer group based load profiles as pseudo

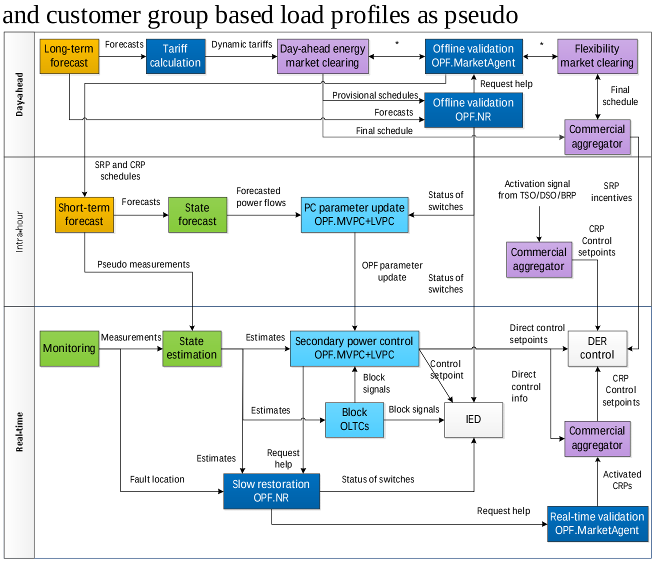

Fig. 4. Interferences of congestion management.

measurements to enhance the observability of the network.

The SC is focusing on coordination of voltage controllers which are under direct control of DSO and to minimize the amount of production curtailment or load control needed in the control area. Therefore the SC is adjusting settings of two different kinds of primary controllers: IED and DER control. IED includes e.g. Automatic Voltage Controller (AVC) of OLTC and Automatic Voltage Regulator (AVR) of dSTATCOM both owned by DSO. DER control includes both the contracted control and the emergency control of DERs. Contracted control includes e.g. AVR of DG or production curtailment in case of non-firm connection contract. SC will also inform CA in case of emergency control of DERs. Block OLTC is coordinating the functioning of real-time SCs and AVC of OLTCs when two or more OLTCs are operated in cascade and AVC delay grading is not efficient enough method from voltage quality viewpoint. [12]

Real-time SCs may also request help from the TC to solve the congestion. Slow restoration will reconfigure the network and if this is not enough, then the real-time validation is requested. OPF of market agent is activated to activate already procured CRPs, and to refuse/curtail new CRPs requested to be activated by third parties. If a fault has occurred, then the slow restoration is activated to isolate fault and restore supply.

The benefit of integrating day-ahead, intra-hour and real-time scales consists of minimizing the unanticipated interventions on the more demanding real-time scale, exploiting at best all available knowledge of the system state and evolution, being able to accommodate business and technical interactions on very different time scales.

V. Analysis of proposed system and use cases

A. Monitoring

The proposed monitoring architecture covers all the levels of the grid including primary substations, secondary substations and collecting data also from MV and LV customer connections points. With the aim of managing the complexity and the big amount of data coming from the distribution grid a hierarchical and distributed architecture has been proposed. Following the hierarchy of the system, two data acquisition points can be identified.

Secondary Substation data acquisition: it is the lowest layer of the grid and the most detailed monitoring system which permits to acquire electrical measurements (powers, voltages, currents, etc.) with the highest granularity. To implement this layer a new generation of smart meters has been installed in each of the LV customers and in some LV grid nodes. These meters, using a broadband power line communication infrastructure and the DLMS/COSEM protocol, provide real-time measures and energies profiles to the secondary SAU [13]. In the SAU measures are stored in a local database and they are used, together with measures of secondary substation measurement units, controllers (e.g. feeder breakers) and protection devices, to perform state estimation/forecast and secondary power control in the LV grid. Some aggregated values (e.g the load of the MV/LV transformer are then exposed to the MV monitoring functions instantiated in the primary substation SAU through an IEC61850 MMS server with a dedicated data model. In this way each measure is transmitted and managed till the level where it is useful.

Primary Substation data acquisition: this layer acquires data from the MV grid using a set of protection devices and retrieving data from the secondary SAUs (here a IEC61850 MMS client is present). The communication infrastructure could take advantage of several physical communication channels (broadband power line, fiber optics, public ADSL, WiFi, etc.) [14] and the IEC61850 MMS protocol. The collected data is used locally by MV grid state estimation/forecast and secondary power control.

These two layers covered the requirements defined by the monitoring use cases. The proposed architecture provides the amount of measurements with the needed detail level to control the entire distribution network. At the same time, the distribution of the monitoring actors over all layers of the grid allows a reduction of the data exchanged permitting a reduction of ICT costs and decentralization of data storage and decision making from control centre to substations. This enables the scalability of management approach to complete MV and LV grid where the number of measurement points is increasing exponentially compared to traditional centralized systems. The implementation of proposed automation system is based on international standards used for information models and data exchange which enable seamless data integration and exchange. [7,10]

B. State Estimation

The proposed automation architecture enables for example decentralization of state estimation to primary and secondary substations. Reference [15] provides test results of LV state estimation utilizing real-time measurements of monitoring system, network data, and load profiles. Algorithm is based on the three-phase branch current based state estimator exploiting equality constrained weighted least squares optimization.

Fig. 5 and 6 show how the meter reading frequency and averaging times effect on the state estimation accuracy. The

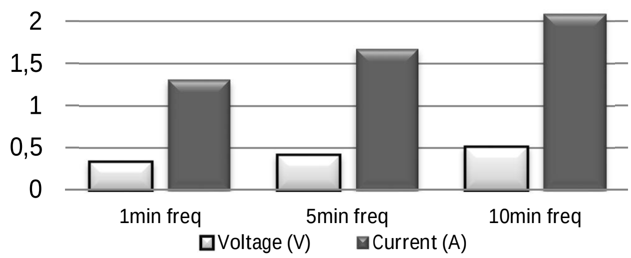

Fig. 5. Average estimation RMS error when smart meter reading frequency is varied. (10 minute averaging time, units are volt and ampere)

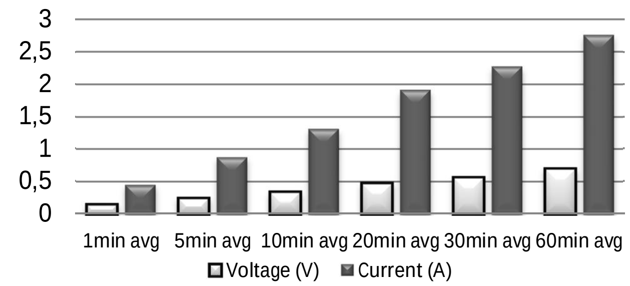

Fig. 6. Average estimation RMS error when smart meter averaging time is varied. (One minute reading frequency, units are volt and ampere)

meter reading frequency should be chosen as high as possible taking technical and economic constraints into account. Then the measurement averaging time is set to the same value, otherwise some of the measurement information will be lost. By combining the low latency RTU measurements with the smart meter measurements, the state estimator is able to improve the estimation accuracy. The accuracy of peak load estimation depends largely on the measurement averaging time. The meter reading frequency affects the response time of peak current observation.

C. Secondary LV Voltage Control

The voltage of European type networks has been controlled by OLTC of HV/MV transformer only. MV feeder capacitors are not utilized, MV/LV transformers may have off-line taps and unity power factor is required for DG units. Recently the rapid development of solar power has challenged the voltage management of LV networks.

The comparison of the voltage control schemes is represented in [16]. While AVC of the OLTC of MV/LV transformer is quite effective alone, it may not detect a situation where the voltage is very high at the end of the LV feeder while substation voltage is within allowed limits. The AVR of the DG unit is able to lower the voltage violation to some degree, but it does not have a high capability. The use of the AVR also clearly increases the network losses. The combined local voltage control scheme (AVC + AVR with dead band) has relatively good performance.

The secondary voltage control scheme may further enhance the network hosting capacity for DG units compared to local voltage control schemes [11,16]. Besides having very low network losses it is also the only control scheme that was capable of maintaining voltages within the allowed limits in every loading case. This is thanks to the optimization of set points of IEDs and the option to curtail production.

LV grid management becomes possible by utilizing hierarchical and distributed automation architecture proposed in the paper. Otherwise real-time data should be delivered to control centre which is not practical for LV grids. Similarly the hierarchical control scheme and dedicated control areas enable the implementation of secondary controller in practice.

VI. Conclusions

Holistic view of active network management utilizing advanced distribution automation and flexibility services from commercial aggregator has been described in the paper. Hierarchical and distributed architecture of distribution automation system has also been described. MV and LV grid monitoring and power control use cases utilizing the proposed automation architecture has been clarified and first set of demonstration results have been given as an example of the performance of proposed system and use cases.

Full exploitation of proposed ideas requires radical changes in distribution network design. However this will lead to significant improvement of distribution network efficiency in terms of network capital and operational costs, and will provide a remarkable increase in network hosting capacity for renewable energy sources and distributed energy resources. The proposed automation system is based on standards, it is scalable to monitor and control of whole distribution grid, and it may be implemented utilizing off-the-self products. The drawback of proposed ideas is notable increment in complexity of distribution network design and operation.

The integration of controllable distributed energy resources is based on market approach where resources are controlled indirectly from distribution system operator’s viewpoint. Distributed energy resources are merges by commercial aggregators which have the roles of retailer and balance responsible party to participate in wholesale market, balancing market and portfolio optimization. Distribution system operator has a role to validate flexibility service requests and to purchase flexibility services like scheduled and conditional re-profiling products from commercial aggregators to solve congestion in the distribution network.

The aim of proposed ideas is to enable active network management by creating a platform for information exchange and functionalities within distribution domain and between domains affecting on it. Active participation of end-customers is a necessary requirement for such system. Technical requirements are scalable and fast responsive automation system to monitor and control whole distribution grid.

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RTDS Simulations of Coordinated Voltage Control in Low Voltage Distribution Network

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Abstract—**Voltage rise effect in distribution networks poses challenges when increasing amounts of Distributed Energy Resources(DERs) are connected to the network. The voltage rise at connection point is usually the limiting factor of the network's DER hosting capacity. Rapid development and deployment of PV generation has introduced the voltage rise problem to LV networks. This paper demonstrates functional performance of coordinated voltage control for voltage rise mitigation in LV networks with several DERs. Real-Time Digital Simulator (RTDS) is used to run the simulations in real-time environment. Implementation of the coordinated voltage control scheme in LV networks is introduced and a new automation architecture is proposed.**

I. Introduction

Increasing amount of distributed energy resources (DERs); distributed generation (DG) and energy storages among others are being connected to the distribution networks. The introduction of these poses challenges to normal distribution network operation as they alter the prevailing assumptions in distribution network planning. Power flows are traditionally expected to be unidirectional from the substation towards customer loads. With connection of DGs near ends of the feeders, the power flows can become bidirectional during times of positive net-generation(generation is higher than consumption). During times of reverse power flow, a voltage rise is introduced at the DG connection point. Distribution System Operators (DSOs) usually limit the allowed voltage rise at DG connection point. The limitation has effect on the DG connection capacity and therefore the profitability of the investment.

In order to increase the network's hosting capacity i.e. allow more DGs to be connected, the network needs to be reinforced or the DERs have to be included in active network management. Reinforcements such as increasing the conductor size or a new feeder are typical but not persevering in terms of the future distribution network operation. Instead, control possibilities of DERs and on-load tap changing (OLTC) transformer can be utilized e.g. in lowering the voltage rise effect, and to optimize the network operation by lowering network losses and increasing hosting capacity simultaneously.

PV generation has been following an exponential worldwide growth during the last decade and now the owners are more often households. LV feeders with high aggregated installed capacity, with long distances or with generation concentrated far from the distribution transformer are prone to similar effects on voltage profile as have been observed in MV networks with DG units at the end of the feeders [1]. Fewer control strategies have been proposed for LV networks compared to the equivalent for MV networks, the difference being efficiency of control methods due to different characteristics of MV and LV networks. Following strategies have been proposed to mitigate the voltage rise caused by the high penetration of renewables in both of these networks:

1) reducing transformer short circuit resistance, and feeder impedance by increasing conductor size [1]
2) OLTC to reduce substation and downstream voltages [2]
3) utilizing reactive power capability of DG units [3]
4) production curtailment of DG units [4]
5) utilizing energy storages [5]
6) demand side management [6]
7) or combining the above [7]-[9].

The strategies can be distinguished to local strategies, where no communication infrastructure is used[3], and coordinated strategies [4],[7], where communication is required between the resources and the coordinating actor. Coordinated voltage control (CVC) schemes of several of the listed resources are extensively studied in MV networks. In LV networks coordinating the control capabilities of DERs with OLTC is found to be superior to the local control of DERs in [10].

Common to studying these voltage control methods is simulation in time domain (PSCAD, OpenDSS) which excludes data transfer, and the complexity of automation and communication architecture of a real network implementation. Instead, real-time simulations are beneficial in confirming the operation and performance of the schemes in real networks before deployment on field. Data transfer from DERs directly to control center can be used if relatively low number of DERs are used in the coordinated control. View of future active distribution network presented in [11] suggests distributed automation architecture with high penetration of DERs. A concept of such architecture has been developed within IDE4L-project where LV network monitoring and control is realized from the secondary substation.

In this paper a LV network CVC scheme with the IDE4L-

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concept automation and communication architecture is put into practice. Performance of the studied scheme is observed in RTDS along with the implemented automation and communication architecture, and real measurement and control devices connected to the simulation system.

II. Automation Architecture

Increasing amount of real-time measurements are available in future distribution networks. Collecting this data from the vicinity of LV customers directly to control center and Distribution Management System (DMS) in real-time causes heavy burden on the communication system. By decentralizing the automation and decision making also at lower levels of automation brings relief to this burden. An automation unit at primary substation monitors and controls MV network and further LV networks are monitored and controlled by similar units at the secondary substations.

The controllers are referred as Substation Automation Units (SAUs). Secondary substation SAU (SSAU) is designed to monitor the LV network and to collect measurements to be stored in a database, and then runs control functions to control the LV network it is responsible of. A SAU consists of functions i.e. algorithms, interfaces and the database. Interfaces are used to communicate with field devices and upper level controllers, other SAUs and DMS, and for algorithm-database two-way data transfer. The SAU and its database are developed in a standard-based manner, which means it is interoperable with any vendor's distribution automation devices. IEC 61850 data model is used in monitoring and control: measurements are read from, and set points and commands calculated by control functions are written to IEDs using IEC 61850 MMS reporting. Common standard in the field of smart metering, DLMS/COSEM, is used to communicate with smart meters.[12]

For the use of functions the SAU needs to store information mainly related to network topology and real-time measurements from the field. The measurements can include smart meter readings from customers, power measurements from generating units and substation measurements from Remote Terminal Unit (RTU). SAU database tables are designed to represent data according to Common Information Model (CIM) and IEC 61850 data model. Dedicated database schemas represent dynamic measurement and control information, and static network information. IEC 61850 data model is used for the former and CIM for the latter. These two schemas are joined together with a bridge model to generate a link between a measurement or control command and specific network location.

III. Coordinated Voltage Control implementation

One of the possible SAU algorithms is the CVC, or Power Control, algorithm. CVC requires extensive information of the current network state as input. Therefore, a weighted least squares based State Estimation (SE) algorithm [13] is used to provide estimates of node voltages and real and reactive powers of each load and production node as dynamic inputs for the CVC. The SE uses substation feeder measurements from RTU, voltage and power measurements from smart meters, and generator real and reactive power measurements directly from RTDS as inputs. If nodes don't have real-time measurements available, forecasts are used as pseudo-measurements. Static network information is maintained in the SAU database. Network topology, network location of controllable resources, and transformer and feeding network parameters are queried by the CVC algorithm during initialization process.

The optimization in CVC algorithm is a mixed-integer nonlinear programming problem. The used optimization algorithm was developed in [9] as a MATLAB program. The current algorithm is run as an Octave program which brings some differences to the earlier MATLAB implementation. Octave, with language which is mostly compatible with MATLAB, is available as a free software. The algorithm has been further developed so that the target function value which the optimization aims to minimize includes, in addition to network losses and curtailed production, a cost parameter for load control, cost for tap changer operations and cost for voltage difference from nominal at each network node. The new target function is formulated as

$$\begin{aligned} f = {} & C_{losses}P_{losses} + C_{cur}\sum P_{cur} \\ & + C_{tap}n_{tap} + C_{Vdiff}\sum (V_{i,r} - V_i)^2 \\ & + C_{DR}\sum \Delta P_{DR}. \end{aligned} \tag{1}$$

Solving of the optimization problem is done using sequential quadratic programming (SQP). In SQP, solving a series of approximates of the original nonlinear problem, which represents behavior at optimal solution of previous iteration round, converges to a solution of the original problem [14].The target function value is also compared to target function value with previous set points. Outputs are not written if the improvement in the network operation is minor. This limits possible hunting behavior and the amount of small incremental changes to e.g. reactive power set points.

With the static and dynamic inputs set points for available controllable resources are calculated once every minute. The CVC algorithm outputs voltage reference value V_{ref} for substation AVC relay, and set points for real power (0-100% of nominal) and reactive power (true value in kVArs) of the PV units. The set points are first stored in dynamic measure&command schema of the SAU database, from where IEC 61850 MMS reading to the control devices is invoked when a new value appears in specific table. Outputs and parameters related to the CVC algorithm execution are stored in dedicated monitoring table in the database. Using these values and historic measurement values in the database the operation and performance of CVC scheme can be evaluated.

Controllable loads are not yet part of the simulation system but the algorithm is capable of utilizing them, which is planned in future work. Earlier implementation assumed symmetrical loading and the network was modeled within the algorithm as single-phase equivalent. Now the algorithm has been remade to use three-phase network model from the SAU database and therefore is also capable of optimizing unbalanced conditions.

IV. RTDS Simulation system

RTDS system in TUT consists of two racks which house the RTDS hardware. New generation PB5 processor cards calculate network solutions and components of the simulation model. All calculations are performed in real-time which enables connection of commercial IEDs to the simulation system. The IEDs can measure the simulation network and perform control actions similarly to real network operation. Included IEDs are an AVC relay controlling the substation voltage reference and the on-load tap changer, an RTU providing power measurements from the substation, and two smart meters connected to measure two critical load nodes in the network model. Amplifiers or adapters are needed with some of the devices when using RTDS signal inputs and outputs. The simulation network model is built and run on RSCAD software which is on a dedicated Windows computer. The computer also runs an instance of MATLAB to provide generator measurements to SAU database and set points from SAU database to modeled PV units through Socket TCP communication. This is for DGs with no IED controlling the unit due to RTDS hardware limitations.

The SAU hardware is a separate Linux computer. Software running on SAU include IEC 61850 MMS server/client, DLMS/COSEM client, PostgreSQL 9.4 database, LV network state estimation algorithm and LV network power control (PC) algorithm. The RTDS simulation environment is depicted in Fig. 1.

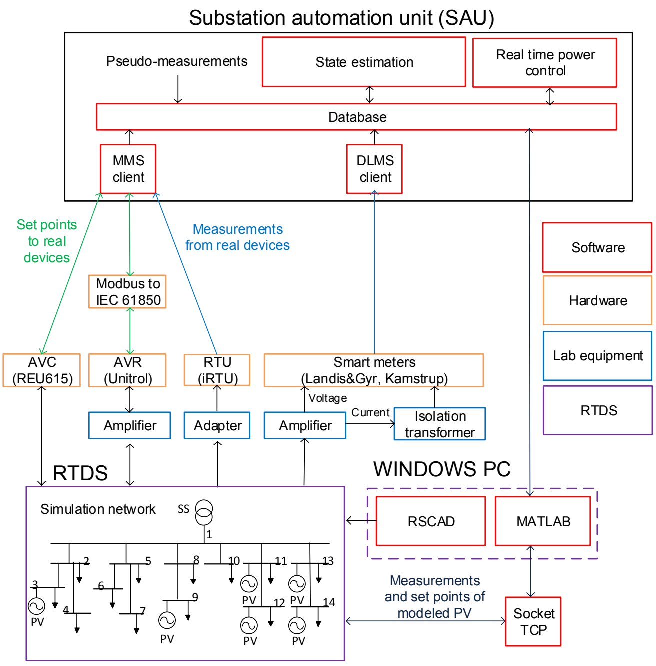

Fig. 1. RTDS laboratory environment

A. Simulation network model

The simulation network model in RSCAD is a real LV network owned by an Italian DSO. The network consists of a secondary substation, where the SAU would be physically located, a transformer with OLTC and six feeders. PV generation in the network is distributed to six nodes on four different feeders. Static constant power loads are connected to each network node to represent customers. The network model is depicted within RTDS in Fig. 1.

Initial real power generation values of the DG units used in the simulations are presented in Table I. The values are slightly below nominal powers of the DG units except at node 14 the DG is at nominal to observe an unit without reactive power capability.

TABLE I
PV unit generation (kW)

DG node	3	9	11	12	13	14
Generation	61.2	60.3	57.6	59.4	62.1	70.02
Nominal power	83.16	87.03	85.14	70.38	88.92	70.02

B. Simulation sequences

Artificial simulation sequences have been created to cause voltage violations in the simulation network. The sequences mimic conditions from real network data gathered by the DSO with PV generation multiplied by a factor of 3 to further observe the operation of the CVC under more demanding conditions. Voltage limits are set to 5% from nominal.

As controllable loads are not included in the simulation system, changing loading conditions is not particularly interesting. Minimum and maximum loading conditions would be found from times of the day with only little or zero PV generation. Thus, the simulation cases are chosen to represent times around noon when the PV generation is expected to peak but can also vary in within time interval of minutes with changing weather conditions. Peak generation can be similar daily, but during these times different loading conditions can be extracted from the DSO's data. Week days typically have less load than Saturdays and Sundays. The difference is estimated to be 2.5 times higher loading on Sundays compared to week days.

Simulation sequence I loops through the worst case loading and generation conditions. MIN load in Table II represents loading scenario on week days and MAX represents loading on Sundays. The DG outputs are percentages of generation column in Table I. The changes are executed every three minutes after the initial change in order to let optimization run a few times during stable network operation.

Feeding MV network voltage can vary due to MV loading conditions and faults in HV network. Sequence II has been created to go through possible worst case scenarios. It is expected that PC algorithm does not proceed into the optimization loop during outside voltage variations. Instead, it detects AVC relay or tap changer operating signal or compares the current

TABLE II
SIMULATION SEQUENCE I - WORST CASE LOADING AND GENERATION SCENARIOS

Time	DG output	Loading
0s	100 %	MIN
50s	30 %	MIN
230s	30 %	MAX
410s	100 %	MAX
600s	End	End

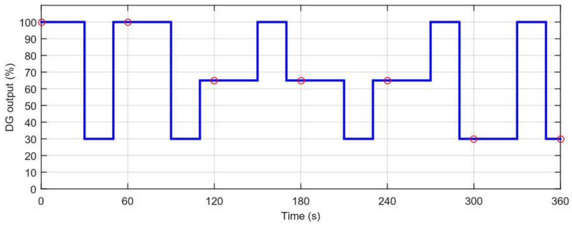

Fig. 2. Simulation sequence III - intra-minute variations

substation voltage to the reference, and waits before AVC relay and tap changer have operated. The sequence introduces disturbances every two minutes to allow PC algorithm to detect prevailing network state after AVC relay has operated.

TABLE III
SIMULATION SEQUENCE II - FEEDING NETWORK VOLTAGE VARIATIONS

Time	Feeding network voltage (kV)
0s	14.63
50s	13.98
170s	14.63
290s	14.98
420s	End

Taking into account measurement retrieval interval, algorithm execution times and communication delays, the algorithms have been chosen to run once every minute. Having the algorithms run once in a minute, events in the network causing voltage fluctuations intra-minute are not detected by the algorithms. Latest measurements or estimates within a validity time are used each time SE and PC algorithms are executed. Sequence III in Fig. 2 demonstrates this case. Red marker points are moments when the algorithms are run.

Lastly as the optimization algorithm tries to minimize the target function value, the cost coefficients have great impact on the outputs. Three cost parameter cases have been considered. First C_{tap} is set to 0 to allow tap changer operation in any case, and C_{cur} is kept high enough to avoid production curtailment. C_{DR} is not considered as there are no controllable loads. The proportion of C_{losses} and C_{Vdiff} is changed in other cases to allow optimization to find values further away from voltage limits at the cost of increased losses. Case2 increases cost for tap changer operations and adds a minor cost for voltage difference, and Case3 further increases the C_{Vdiff}. The effect of cost parameters are then compared. The used parameters are listed Table IV. Simulations of other sequences are run with Case1 parameters.

TABLE IV
COST PARAMETERS CASES, $S_b = 20$

Case	Ctap	Ccur	Closses	CVdiff
1	0	10*Sb	5*Sb	0
2	1	10*Sb	5*Sb	5*Sb
3	1	10*Sb	5*Sb	500*Sb

V. SIMULATION RESULTS

The simulation results are presented using graphs and key performance indicators (KPIs). The graphs are drawn and the KPIs calculated from measurement history of the SAU database or directly from the RTDS. Network node voltages and plots with RTDS suffix are direct measurements from RTDS.

A. *Worst case loading and generation scenarios*

Fig. 3 presents graphs for the sequence I. The first change was made at 12:49:50 by reducing all DG output to 30%. This caused tap changer operation to increase substation voltage and lowering reactive power generation. Next change at 12:52:50 increased the loads by a factor of 2.5 which invoked CVC to increase reactive power generation of all DG units. Last change back to 100% generation caused voltage violations and the tap position was set back to the original.

New set points for reactive powers were given after each change made in the network. Between changes the target function value did not change enough and the reactive power set points were preserved. The voltages remained within limits most of the time, and network losses were optimized by keeping the voltages closer to the allowed limits as no cost for voltage difference is set. The total use of reactive power was moderate considering the available capability.

B. *Feeding network voltage variations*

Fig. 4 presents graphs for simulation sequence II. The sequence started at 13:21:00 and at 13:21:50 the feeding network was lowered to the minimum. Due to tap changer operating delay, the state estimation was run when the tap changer had operated once, even though it operated once more afterwards. This did not cause any unnecessary control actions as PC algorithm detected the outside voltage variations and did not run optimization when AVC relay or tap changer was operating. At 13:23:00 the voltage estimate was then corrected and PC ran again with no changes to set points as voltages were within limits. When feeding network voltage was returned to the original value at 13:23:50, over-voltages were introduced to the network due to the newly set tap position, but were shortly corrected after. Again, PC did not go into optimization loop and waited for tap changer operations. This applied also to the last changes made in the sequence where over-voltages were again introduced. With the voltages

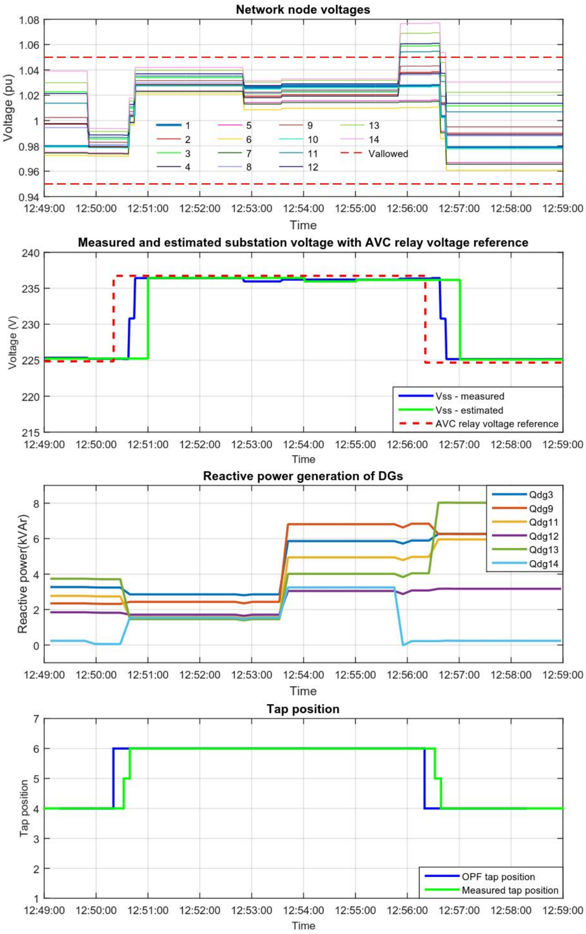

Fig. 3. Sequence I graphs

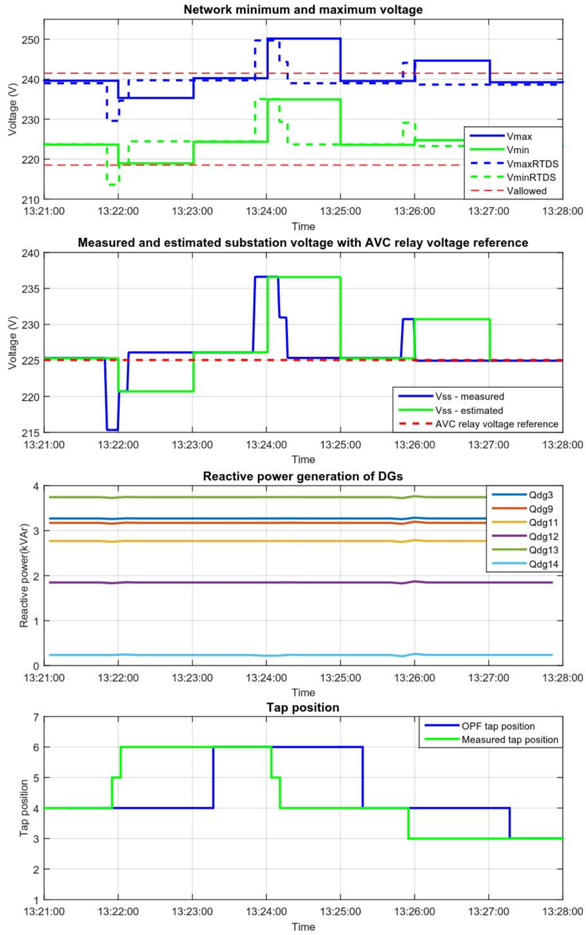

Fig. 4. Sequence II graphs

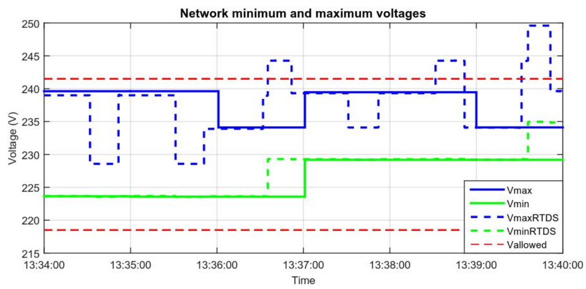

Fig. 5. Network voltage extremes during Sequence III

being within limits, PC did not change reactive power values as the losses are lower when network voltages are closer to the voltage limits. The reactive powers set by PC algorithm initially before running the sequence can be found from the second last graph.

C. Intra-minute voltage variations

Fig. 5 depicts estimated and measured voltages during the Sequence III. Change to 65% DG output 2 minutes after sequence start caused a tap changer operation to increase voltage. What state estimation saw afterwards was the same maximum voltage value until 13:39:00 which in reality had been over the limits twice during this time with the current tap position as the sequence had increased to 100% DG output. This is also visible from Table V sequence III columns where estimated over-voltage volumes and durations voltage is out of bounds were seen by state estimation as zeros but in reality the voltages were violated.

D. Effect of cost parameters

Fig. 6 depicts node voltages and reactive powers in Sequence I when cost parameter for voltage difference was increased to 500*Sb. In contrast to graphs in Fig. 3 the voltages were now much closer to nominal and reactive power was used extensively at the cost of increased losses.

Table V lists calculated KPI values for simulation sequences I and III in all cost parameter cases. In Sequence I over-voltage volumes and voltage out of bounds times were reduced when comparing Cases 2 and 3 with Case 1. In Case 3 longer algorithm execution time allowed over-voltages to remain in the network for longer period of time. In Sequence III the sequential cases reduced over-voltage volume and voltage out of bounds duration down to zero at Case 3. In general Case

TABLE V
COST PARAMETERS CASES

KPI (estimate / RTDS)	I Case 1	I Case 2	I Case 3	III Case 1	III Case 2	III Case 3
Network losses [kWs]	2860 / 2729	2875 / 2775	3271 / 3031	2324 / 2375	2358 / 2440	2952 / 2757
Average target function value	29.62	28.51	108.54	36.12	38.22	161.05
Average PC execution time [s]	16.90	14.89	26.48	17.22	15.05	22.99
OLTC actions [pcs]	4	2	2	2	1	0
V set point changes [pcs]	2	2	2	2	1	0
Q set point changes [pcs]	18	20	47	17	22	34
Over-voltage volume [pu*s]	4.12 / 3.33	0.30 / 0.16	0.80 / 0.38	0 / 2.21	0 / 0.13	0 / 0
Under-voltage volume [pu*s]	0 / 0	0 / 0	0 / 0	0 / 0	0 / 0	0 / 0
Voltage out of bounds [s]	295 / 240.3	60 / 49.3	118 / 64.79	0 / 168.7	0 / 18.3	0 / 0

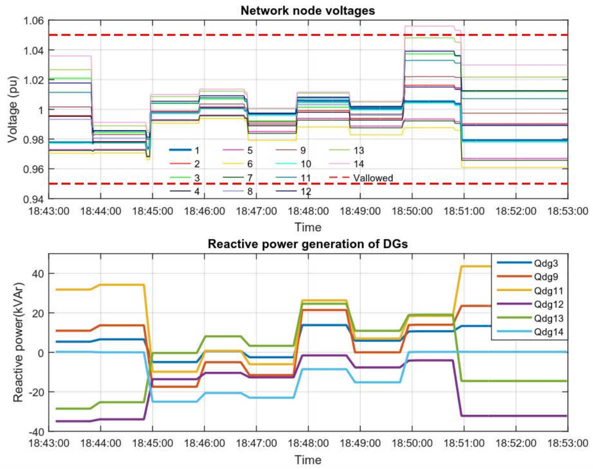

Fig. 6. Cost parameter Case3 graphs in Sequence I

2 reduced the amount of tap changer operations and slightly increased Q set point changes, and Case 3 greatly increased Q set point changes at the cost of network losses and target function value increase.

VI. CONCLUSION

RTDS was used to test the operation of the proposed automation architecture and CVC implementation in modeled real LV network. Real-time environment was used to validate the co-operation of the introduced SAU and its database, algorithms required in the voltage control scheme, and all interfaces with the real measurement and control IEDs, and further to identify practical issues that might arise when implementing the same in real network.

The algorithms operated as expected during the simulations. KPIs and graphs confirm the performance of the CVC scheme under demanding artificial conditions. To avoid over-voltages, the network voltages should be optimized further away from the desired network voltage limits by using the voltage difference cost parameter or lower voltage limits within the optimization algorithm. Communication and operating delays, and algorithm execution times proved to have effect on the performance of the control scheme.

The scheme is ready to be tested with current features in field. The tested scheme is also capable of utilizing production curtailment as last resort resource, and functions under unbalanced network conditions with one-phase PV inverters and unsymmetrical loads. In future load control is possible addition to the controllable resources.

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