No 727481 RESERVE

D1.2 *Requirements placed on energy systems on transition to 100% RES*

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Abstract

Discussed in this report are the required components and functions that future automation systems must have for frequency and voltage control in a power system with 100% RES. The requirements listed in this document are based on 1) the scenarios identified in D1.1 for future 100% RES penetration, 2) the frequency control architectures developing in WP2, and 3) the voltage control architectures developing in WP3. The requirements listed here were derived based on the challenges that come with increasing RES penetration and its effects in the frequency and voltage dynamics. Live and field trials in WP5 and WP4, as well as progress in WP2 and WP3 will confirm or refine the requirements listed in this report. The validated and refined list of requirements will be provided in D1.5 in the future.

Keyword list

Energy System Requirements, 100% RES Energy Networks

Executive Summary

The 100% penetration of renewable energy sources (RES) in a power system (a.k.a. power grid) brings several challenges to automation systems that provide frequency and voltage control. In this document, the power system components and functions needed in automation systems to address these challenges are identified and discussed.

Today, frequency control benefits from the stabilization effects of mechanical inertia from synchronous machines used in fossil-fired, nuclear, hydro, and geothermal plants. On the other hand, solar plants do not have mechanical inertia. Wind plants have mechanical inertia, but the inertia is not injected to the power system because of the plants' power converter. Instead of relying on the natural rotational inertia, future frequency control will use the new Rate-of-Change-of-Frequency (RoCoF) Control. Following a disturbance in the power system, the RoCoF control will provide synthetic inertia to the power system to stabilize frequency.

The RoCoF control may be implemented through the individual and independent control of local plant controllers. It may also be implemented through a RoCoF unit, which commands local controllers based on frequency measurements and estimations.

To support RoCoF control, metering infrastructure must have high-enough granularity and accuracy. Power converters must also have enough power-transfer capabilities to inject large amounts of energy in a relatively short time frame.

Another challenge to frequency control is the intermittency of solar and wind plants. It challenges future frequency control to provide enough reserves to implement the Primary Control (a.k.a. frequency containment) and the Secondary Control (a.k.a. frequency restoration) stages. To address these concerns, future frequency control requires energy storage systems (ESSs) and high-voltage DC (HVDC) links.

To get the benefits from the small, but numerous renewable energy sources (RES), ESS, and load flexibility at the distribution level, future frequency control will also require the participation of emerging actors such as microgrids, aggregators, and/or virtual power plants. DSOs may also have new responsibilities to help in frequency control.

In the project, the application of Linear Swing Dynamics (LSD) is also investigated for controlling frequency in power systems with no mechanical inertia from power generation. This scenario is possible in countries without hydro or geothermal capacities. In this scenario, the expected frequency dynamics are very fast.

Furthermore, the numerous RES and ESSs in the power system will add numerous power converters at the distribution level of the power system. With the presence of numerous power converters, maintaining dynamic voltage becomes an issue.

Maintaining dynamic voltage stability requires the use of Wideband System Identification (WSI) and Virtual Output Impedance (VOI) control. Future power converters must be equipped with WSI tools and VOI controllers to maintain dynamic voltage stability.

WSI involves the injection of noise to the power system. Thus, it is important that WSI does not violate future power quality requirements in the power system.

WSI tools determine the VOI of power converters, as well as relevant grid impedances. These impedances are sent to a Secondary Substation Automation Unit (SSAU) in real-time. The SSAU determines the stability margins of the power system based on the impedances. The SSAU needs to communicate control commands to VOI controllers. These commands will make the power system more stable by modifying the VOI of power converters. Thus, future power systems require a method for determining the desired values for the VOIs. Moreover, DSOs should be allowed to intervene in the process if the SSAU finds dynamic instability in the power system.

The numerous power converters in the distribution level also presents the opportunity to perform active voltage management (AVM). AVM uses optimization to accomplish different objectives such as minimizing power system losses or costs. AVM requires the coordination among the power converter control with the present voltage control devices (e.g. shunt capacitors). AVM will also require power converters to be able to inject or draw reactive power from the grid. Furthermore, AVM requires the optimized Volt-VAR curves that may entail massive data collection.

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Table of Contents

1. Introduction

"What are the equipment and functionalities that future automation systems must have to control frequency and voltage in future power systems with 100% RES?" - this is the question that this document answers in the context of RESERVE.

1.1 Task 1.2

This deliverable is an output of the work done in Task (T) 1.2. This task collects and analyses the requirements in transmission and distribution networks for frequency control and voltage control.

The requirements are identified and analyzed in the context of the scenarios investigated in RESERVE. These scenarios were identified in Deliverable (D) 1.1 through a multidimensional analysis. However, this deliverable uses the updated versions of this scenarios. Updated versions of the scenarios reflect the progress in Work Package (WP) 2 and WP3.

1.2 Objectives of the Work Report in this Deliverable

- To discuss the challenges in frequency control and voltage control due to the proliferation of renewable energy sources (RES) and energy storage systems (ESSs).
- To summarize how the challenges can be addressed by the control concepts proposed in RESERVE.
- To compare control methods and requirements in the present scenario and those in the scenarios investigated in RESERVE.
- To identify and discuss the required power equipment, control equipment, and control functions in transmission and distribution networks. These required equipment and functions are needed to implement frequency control and voltage control in the scenarios investigated in RESERVE.
- To provide a roll-out outlook for the scenarios and their requirements.
- To discuss how the requirements could possibly affect present network codes.
- To discuss the needed support from emerging actors in putting the requirements in place.

1.3 Outline of the Deliverable

The remainder of this report is organized as follows:

Chapter 2 provides a fundamental background of frequency and voltage control. It also discusses the challenges that future automation systems will face due to 100% RES. The chapter ends with an overview of the scenarios studied in RESERVE in relation to the challenges mentioned.

Chapter 3 contains the discussions about the power system requirements for the frequency control scenarios. In other words, the required devices and functions in future automation systems for controlling frequency. It also provides a roll-out outlook for the requirements. In addition, Chapter 3 contains discussions on how emerging actors in the power industry could support the implementation of frequency control in the future. The requirements listed in this chapter will be updated in the future, as research work in WP2 progress.

Chapter 4 provides the power system requirements for the voltage control scenarios. Like Chapter 3, it also provides a roll-out outlook for the requirements, as well as the support needed from emerging actors. The requirements listed in this chapter will be updated in the future, as research work in WP3 progress.

Chapter 5 concludes this report, summarizing the main observations and findings about the challenges and requirements for implementing the control concepts in future automation systems.

Annex A.1 analyses the requirements listed in this document from the perspective of the present network codes.

Annex B.1 summarizes the vision, research questions, assumptions, and scope of the different scenarios investigated in reserve. The scenario descriptions here are still expected to change as progress in WP2 and WP3 continues in the future.

1.4 How to Read this Document

This document could be read on its own. The concepts of frequency control and voltage control are introduced. This allows the reader to appreciate the requirements and discussions contained in this document. The main contributions of this deliverable are the component and functional requirements placed on future-automation systems for voltage and frequency control.

For more in-depth discussions on frequency control methods and concepts, the reader may read D2.1 and D2.2. For more in-depth discussions on voltage control methods and concepts, the reader may read D3.1 and D3.2

D1.1 also provides the multidimensional analysis used to identify the three of the four scenarios investigated in RESERVE. These scenarios are SF_A, SF_B, and SV_A. The remaining scenario, SV_B, was identified in for the project after the submission of D1.1.

Figure 1 shows how D1.2 is related with other deliverables and work packages. The contents of D1.2 are based on the scenarios identified in D1.1 and the architectures developing in WP2 and WP3. The requirements listed here in D1.2 will be updated and refined in the future versions of D1.5. D1.5, which is iterative, will capture the results from simulations, live tests, and field trials in WP2, WP3, WP4, and WP5.

Furthermore, the requirements listed here in D1.2 help in identifying the ICT requirements in D1.3 and defining the use-cases in D1.4.

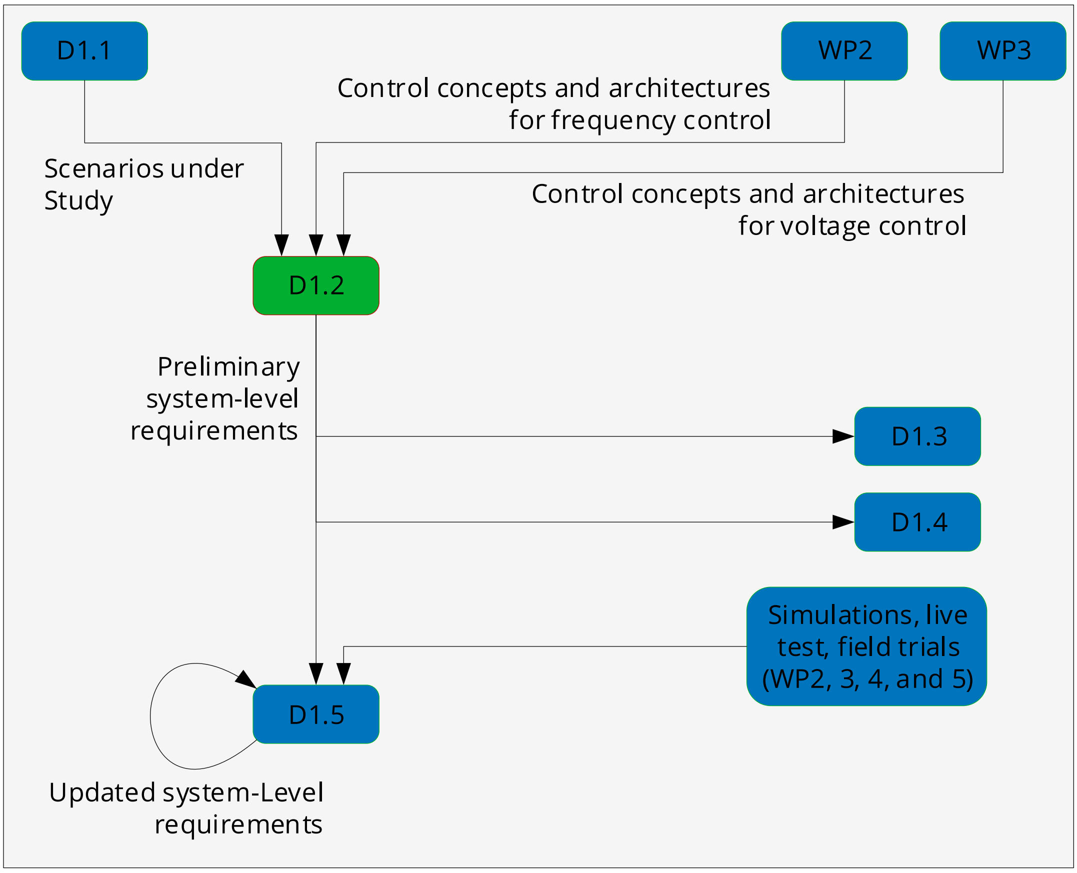

Figure 1. Relation of D1.2 with the other deliverables and work packages in RESERVE

1.5 Approach used to Undertake the Work

The contents of this report developed through the following iterative steps:

1. The descriptions in D1.1 for the scenarios investigated in RESERVE were updated. The updates are based on the progress in WP2 and WP3 since Month 6. Based on the updated scenario descriptions. The challenges in frequency and voltage control addressed by the scenarios were also reviewed

2. Details about the control schemes studied in the different scenarios were collected from project partners and published literature.
3. The component and functional requirements for each scenario were defined and listed. The Smart Grid Architecture Model (SGAM) was used to facilitate the discussions for defining the control architectures and their requirements. The discussions involve the different partners in WP1, WP2, and WP3.
4. The requirements and control architectures were compared to their present counterparts.
5. A roll-out outlook for the requirements were provided based on discussions involving partners from WP1, WP2, and WP3.
6. The requirements were examined to see the support needed from emerging actors to have the requirements in place.
7. A preliminary analysis on the possible effects of the requirements to the present network codes was done.

2. Summary of Trends, Technical Issues, and Challenges in Voltage and Frequency Control

2.1 The AC Voltage Waveform

The power system is a huge and complex system that converts electric energy from different sources. It also facilitates how electric energy moves from the generating units to the electric consumers. The electric energy comes in the form of voltages and currents in the power system.

To facilitate the design and operation of the millions of devices in the power system, power system operators agree to use standard voltages in the power system. Power systems using AC voltages are called AC power systems or AC grids. Likewise, power systems using DC voltages are called DC power systems or DC grids. At the present, most power systems use AC voltages. There is an increasing trend in the use of DC grids. However, the engineering practice and equipment in DC grids are yet to mature in a global scope [1].

AC power systems use sinusoidal AC voltages. These voltages have frequencies and root-mean-square values. For example, the AC voltages at the socket outlets in Germany, Ireland, and Romania use a nominal frequency of 50 Hz. These voltages also use a nominal RMS value of 230 V [2].

2.2 Challenges in control due to 100% RES penetration

This document contains the requirements placed on future automation systems to perform frequency control and voltage control. To perform both controls, automation systems need to overcome the challenges brought by the transition to 100% renewable energy sources (RES). These challenges are summarized as follows:

1. Fossil, nuclear, hydro, geothermal, and biogas plants have mechanical inertia that stabilizes the frequency. With less generation share from fossil and nuclear plants, there will be less mechanical inertia in the power system. With less mechanical inertia, the frequency will change faster following a disturbance in future power systems. Thus, the automation systems must respond faster. Future plant controllers, measurement systems, and communication infrastructures must facilitate the faster response.

2. There will be more control endpoints in future power systems. This is because solar and wind plants come in smaller ratings than the present fossil-fuel and nuclear plants. For example, it will require more than sixty 10-MW solar plants to replace one 600-MW coal plant. More than sixty because each solar plant cannot produce 10 MW consistently due to varying weather conditions [3]. In addition to the generating units in power plants, many consumers will also have their own generating units at their own premises. This further adds more control points for future automation systems. Future automation systems must be able to utilize enabling communication systems to coordinate the operation and response of a vast number of generating units.

3. Because of the intermittency of solar and wind generation, keeping sufficient generating reserves in the grid becomes more challenging in power systems with 100% RES. Future automation systems must be able to take advantage of energy storage systems and transmission interconnections to address this challenge.

4. Numerous installations of RES at the distribution system and consumer premises will add many active power converters in the distribution system. This may reduce the dynamic stability of the power system and may lead to unstable oscillations. New infrastructures for monitoring and controlling the grid stability will help address this challenge.

5. Numerous installations of RES at the distribution system and consumer premises will not only add more control points, but it will also change the conventional flow of energy in the power system. This increases the demand for coordination and communication among controllers of RES.

The first three challenges above concern frequency control. The aim of frequency control is it to keep the frequency within the allowed range. These challenges are the concern of two future scenarios investigated in RESERVE, SF_A and SF_B. In both scenarios, all electric energy in the system comes from RES.

In SF_A, hydro plants act as sources of mechanical inertia. This scenario applies to future power systems in countries like Romania where hydro capacity is available.

In SF_B, there are no hydro plants, and all generating units connect to the grid via power converters. Thus, the grid has zero mechanical inertia in SF_B. It is important to investigate this scenario in RESERVE to include the worst possible conditions in countries without hydro and geothermal resources.

The fourth challenge concerns dynamic voltage stability. This challenge is the concern of SV_A. SV_A is a scenario investigated in RESERVE for voltage control. In this scenario, future automation systems require a new infrastructure that will track and control the dynamic stability of the power system.

Moreover, the fifth challenge presents an opportunity for voltage management. This opportunity is the concern of SV_B. Like SV_A, SV_B is another scenario investigated in RESERVE for voltage control. Here, we envision using an active voltage management architecture using the power converters of electric customers. This architecture will control the RMS value of the voltages in the power system for various objectives. The aim could be to cut energy losses, cut costs, or balance loads among the phases of the feeder.

2.3 Overview of the scenarios studied in RESERVE

In total, there are four scenarios investigated in RESERVE. Two scenarios, SF_A and SF_B, are concerned with frequency control. The other two scenarios, SV_A and SV_B, are concerned with voltage control. Scenarios SF_A, SF_B, and SV_A were identified in D1.1 using multi-dimensional analysis. SV_B, on the other hand, developed after the submission of D1.1. The next subsection gives an overview of these four scenarios.

2.3.1 Scenarios for Frequency Control

In future power systems with 100% RES, a significant share of generating units will connect to the grid via power converters. This leads to less mechanical inertia in the power system. With less mechanical inertia, disturbances in the power system will result in faster and bigger frequency deviations, as shown in Figure 2. In Figure 2, the acceleration time constant (TA) of the power system represents power system inertia. The lower the time constant, the lower the inertia.

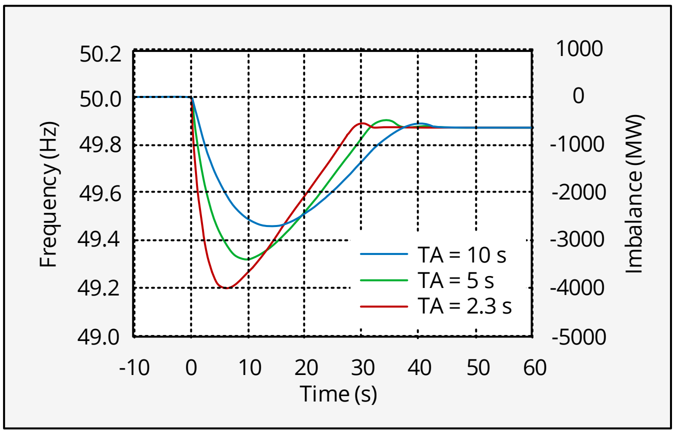

Figure 2. Effect of inertia on the frequency deviations following a disturbance [4].

Without improvements from its present state, frequency control will not be able to do the following tasks in power systems with low inertia:

1) Slow down the changes in frequency following disturbance.

2) Maintain the maximum deviations in frequency within the allowable range.

3) Use future ESSs and intermittent reserves from solar and wind to contain the frequency and bring it back to the ideal value.

Thus, we look at the research work for SF_A to address these concerns for the future power systems with 100% RES including hydro. Like the case in SF_A, the research work for SF_B also addresses these concerns for future power systems. However, in SF_B, there will be no hydro plants providing inertia to the power systems.

Through the concept of linear swing dynamics (LSD), the researchers work in SF_B envision a faster control scheme for SF_B compared to that in SF_A. One of the reason is that the frequency will change faster and violate the limits sooner if the control systems are not fast enough. Another reason is that the power converters can provide control faster than the regulation provided by synchronous machine controllers (e.g. turbine governors). The synchronous machines are responding naturally to provide the inertia, but they have very slow response compared to those of converter-interfaced generating units.

Furthermore, SF_B also accounts the presence of DC grids in the future power systems. The research work in SF_B envision that DC grids will not only make the power system more efficient, but also help in frequency control as proposed in literature [5], [6], [7].

The control schemes studied in both SF_A and SF_B have the following control stages:

1. RoCoF control (a.k.a. inertial control) that will allow ESSs, wind plants, storage-connected solar plants provide synthetic inertia to the power system to slow down the changes in frequency.

2. Primary control (a.k.a. frequency containment) that will make the frequency settle within an allowed range.

3. Secondary control (a.k.a. frequency restoration or automatic generation control) that will restore the frequency to its ideal value.

These stages may still change as research work in SF_A and SF_B progress.

The research work in SF_A and SF_B focus on the high- and medium-level voltage part of the grid since bigger generating units will connect to it. Individual customers will generate less compared to the power plants. Yet, aggregation of customer RES and ESSs allow these units to act as one, enabling operators to use them for frequency control. The aggregation of RES and ESSs can come in the form of commercial virtual power plants (CVPP), technical virtual power plants (TVPP), and microgrids [8]. Both SF_A and SF_B consider the aggregation of RES and ESSs in the future.

The researchers in WP2 expect that the investigation and results in both SF_A and SF_B will be applicable in future power systems (2030+). However, isolated microgrids in the next generation power systems (2020+) running on 100% RES may adopt the control architecture studied in SF_A or SF_B sooner.

2.3.2 Scenarios for Voltage Control

There are two scenarios for voltage control studied under RESERVE, SV_A and SV_B. These two scenarios address two different problems: dynamic voltage stability and voltage management.

The research work in SV_A addresses the dynamic instability attributed to the power converters of RES and customers. The research work in SV_A aims to utilize a novel virtual output impedance (VOI) control to prevent the occurrence of unstable voltage oscillations in distribution systems. The researchers in SV_A expect to have these oscillations because of the proliferation of power-electronic-based RES, ESSs, and loads.

Dynamic instability due to the power converters will most likely occur at the low-voltage level, where more power converters will be present compared to the high- and medium voltage levels. Therefore, the research in SV_A focuses on the low-voltage AC grid. However, the control concept in SV_A also applies to low-voltage DC grids. More DC grids will be present in the future to improve efficiency in future power systems with many DC sources and DC electronic loads.

The second scenario for voltage control is SV_B. SV_B focuses on the opportunity to manage the voltage and energy flows using power converters. The research work in SV_B aims to keep the voltage RMS within the allowed range while optimizing the voltages and energy injections from RES and ESSs. Like in SV_A, the researchers in SV_B expect that power converter will be ubiquitous in future power systems, especially at the low-voltage level. Today, the power system operators manage the voltage through on-line tap changing transformers, and shunt devices that inject or draw reactive power. The research work in SV_B may offer a simpler solution in the future as it will not need extra devices installed in the grid.

The researchers in WP3 expect the investigations and results for both SV_A and SV_B to be applicable in the next generation power systems (2020+). However, the researchers expect that SV_B will be relevant to automation systems sooner than SV_A.

2.3.3 Research work for the scenarios

In total, there are four scenarios studied in RESERVE concerning the power system. Two for frequency control and two scenarios for voltage control. Table 1 gives the vision and research questions of each scenario. At the time of writing of this document, the scenario definitions, control concepts, and control architectures for the four scenarios are still developing in WP2 and WP3.

Table 1. Overview of the scenarios

	Scenario	Vision	Research Questions
Frequency Scenarios	**SF_A: Mixed Mechanical-Synthetic Inertia**	Study of frequency in a 100% RES power system with hydro generation, where system inertia will decrease a lot and new dynamic issues will arise.	How to provide synthetic inertia, implement primary and secondary frequency controls considering a decrease in mechanical inertia in a power system with intermittent generation and operating reserves?
	SF_B: Full Synthetic Inertia	Study of frequency in a futuristic power system with HVDC, hybrid AC/DC and very low inertia (from hydro) or with no inertia	How to provide frequency control through the concept of linear swing dynamics (LSD) considering a power system with zero mechanical inertia from generators, intermittent generation, and intermittent operating reserves?
Voltage Scenarios	**SV_A: Dynamic Voltage Stability**	Study of voltage transients, under load and local changes; It deals with voltage harmonics and stability	How to maintain dynamic voltage stability through Virtual Output Impedance (VOI) control in a distribution system where the number of controllable power converters increases?
	SV_B: Active Voltage Management	Study of steady-state voltages in a distribution grid. The focus is on voltage management and not stability.	How to maintain the steady-state voltage within acceptable limits in the face of variable generation and demand growth from RES? Can the inverter technology inherent to a RES be used in a strategic manner to better manage the reactive power needs of a power system towards 100% RES penetration?

3. Frequency Control Scenarios and Requirements

3.1 Control Architectures for Frequency Control

3.1.1 Present Scenario

Four stages of frequency control are defined in ENTSO-E. These are the primary, secondary, tertiary, and time control. The scenarios in RESERVE focus on the primary and secondary stages since the challenges from 100% RES will involve adaptations in the automation systems for these stages. Figure 3 illustrates the effect of the primary and secondary control to the frequency deviation following a disturbance.

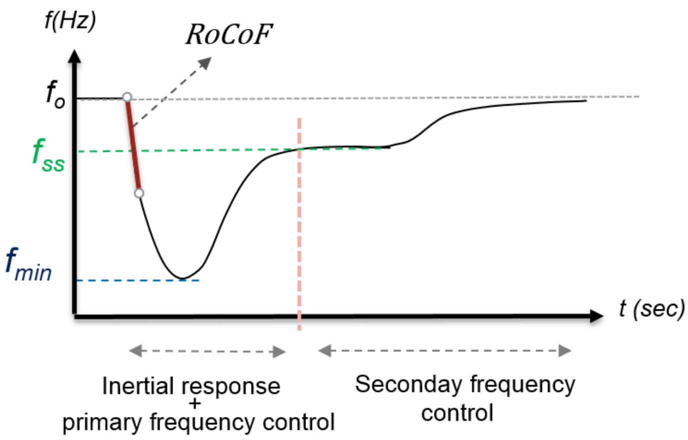

Figure 3. Frequency deviations following a loss in power generation [Source: D1.1]

The primary control is the first control response of today's power systems to limit frequency deviation. The effect of primary control happens on top of the inertial response of the power systems, which is the effect of the mechanical inertia of the power plants' turbines. The objective of primary control is to restore the balance between power generation and power consumption. In the present power systems, each local controller of generating units and participating loads performs primary control and adjusts the generation or consumption based on local measurements. The primary control actions of different generators and loads lead to a steady, albeit non-nominal value of the frequency, as shown in Figure 3. Primary control also uses up reserve generating capacities in the power system. Furthermore, primary control leads to power exchanges between transmission systems that are not equal to the desired or contracted values. At the present, primary control may take up to 30 seconds after the initial frequency deviations occur.

The secondary control starts several seconds after the disturbance and typically lasts 15 minutes after the disturbance. It uses a centralized controller for one control area. It adjusts the generation set points of different generating units to restore the frequency and the power exchanges among transmission systems back to their desired values. The Secondary control also frees up the reserves used in primary control so that they will be available when needed again. Furthermore, it uses measurements and information from different generating units. This information, which includes frequency measurements and power flows, must be transmitted in a reliable manner (e.g. using parallel data links). Secondary controllers are also required to have high availability and reliability, with a back-up system ready to take over control action when necessary.

For secondary control, virtual power plants (VPPs) coordinate the contribution of small DERs, ESSs, and flexible loads connected in the power system. Virtual power plants comprise various distributed generating units, loads, and ESSs. The components participating in the virtual power plant coordinate their operation as to act like one single plant. VPPs can be one of two types: Technical VPP (TVPP) or commercial VPP (CVPP). A TVPP consists of DERs from the same geographic location and provides support for power system operator in running local distribution systems. TVPPs can be considered as active distribution networks, utilizing DERs to optimize the power system operation. In contrast, a CVPP consists of DERs that may or may not be from the same geographic location. In addition, the impact of distribution networks is not considered in

CVPP. CVPPs uses the aggregated operating and cost profile of DERs and flexible loads allowing them to participate in energy markets.

3.1.2 SF_A: Mixed mechanical-synthetic inertia

Figure 4 shows the changes in the power system and the automation systems from the present scenario to the SF_A scenario. In SF_A, all power generation will come from RES, with only the synchronous generation from hydro plants providing mechanical inertia. The higher penetration of converter-interfaced generating units (i.e. solar, wind, and batteries) causes the power system in SF_A to have less mechanical inertia compared to today's power system. Electrical ESSs will also be present in the SF_A scenario, providing support to the system to address the intermittency of solar and wind plants. In addition, AC grids will dominate the power system in SF_A like in today's power systems.

One adaptation in SF_A to address the reduction in mechanical inertia is to make converter-interfaced generating units provide synthetic inertia. This is accomplished through the RoCoF control. The RoCoF unit captures the changes in frequency immediately after the disturbances, and sends the information to the different remote terminal units (RTUs) of the different units participating in frequency control. The local controllers now will have to respond to the information to make the generating units or flexible loads provide synthetic inertia. Synthetic inertia is a sudden release of energy from converter-interfaced generating units to the grid to reduce the changes of frequency in the grid. This is contrast with mechanical inertia, where the sudden release of energy happens due to the rotational inertia of rotating components of the power plant. Wind turbines also have mechanical inertia, but this inertia does not reach the power system due to the power conversion processes in power converters. And so, local controllers in SF_A must perform RoCoF control on top of primary control. The transmission of measurements from the RoCoF units to the local controllers also needs to be allow the controllers to provide synthetic inertia immediately after the disturbance. Multiple RoCoF units are required to measure the frequency of the power system, because it is assumed in SF_A that the frequency in different parts of the power system may be different from each other.

The primary control and secondary control in SF_A will be like their present counterparts in terms of objectives. The primary control will still contain the frequency within allowed values. Likewise, the secondary control will still restore the frequency back to its nominal value. The secondary control will also restore the power exchanges among transmission systems back to their desired values. In terms of timeframe, the research work in SF_A seeks to speed-up both primary and secondary control. Another change in the power system that future automation systems must consider is the increase in the number of control points. Solar and wind plants have smaller ratings compared to the fossil and nuclear plants that they will displace. Therefore, in terms of number, there are more plants, thus more control points, required to meet the same demand with the penetration and wind.

The tertiary control is placed outside the scope of the scenarios under study for frequency control. This is because fast communication systems are not critical in it. The power system operator can even perform it manually. The goal of tertiary control is to free up reserves used in secondary control, and redistribute generation in an economic manner [9].

The time control is also placed outside the scope of scenarios under study for frequency control. Time control only corrects the synchronous time so it becomes equal to the universal coordinated time (UTC). Discrepancies between the synchronous time and the UTC are due to the discrepancies between the mean frequency and the nominal frequency. These discrepancies serve as a performance index for the primary, secondary and tertiary control [9].

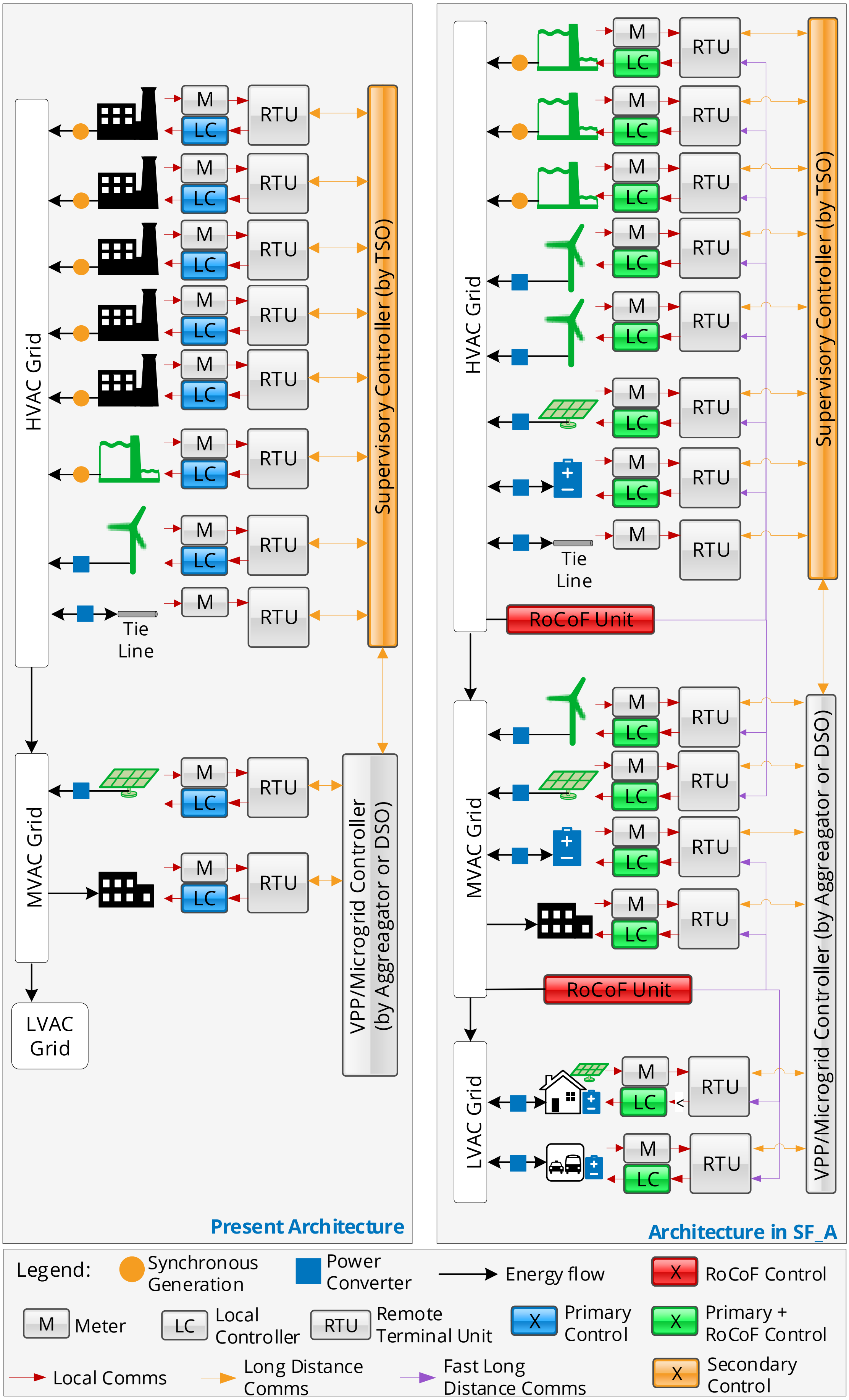

Figure 4. Frequency control architectures today and in SF_A

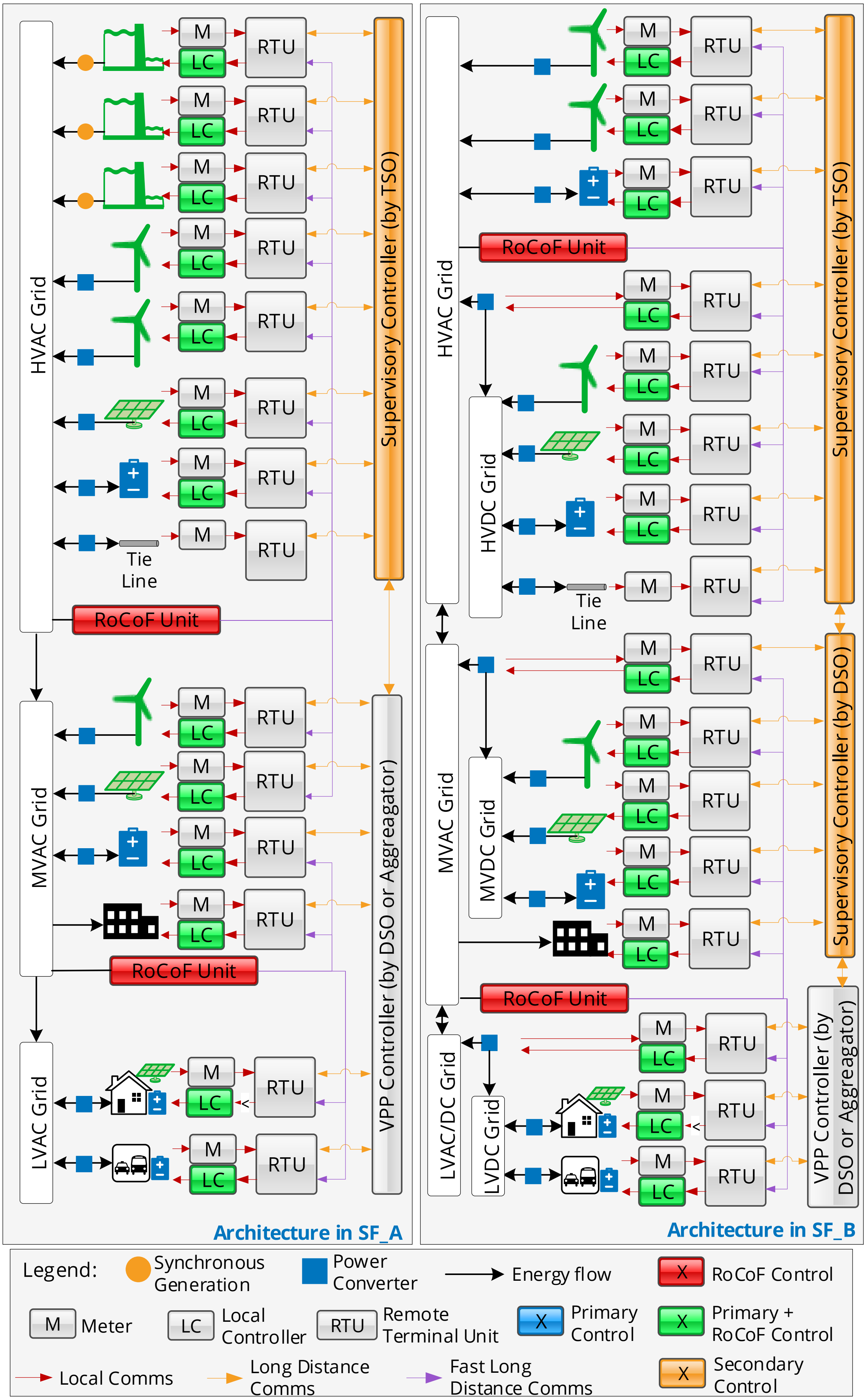

Figure 5. Frequency control architectures in SF_A and SF_B

3.1.3 SF_B: Full Synthetic Inertia

The differences in SF_A and SF_B in terms of power and automation systems requirements are shown in Figure 5.

In SF_B, there will 100% penetration of solar and wind generation. This means that all generating units are interfaced with power system via power converters. This also means that no generating units will supply mechanical inertia to the power system.

Also, in contrast with SF_A, SF_B will consider the use of DC grids in the different voltage levels of the power system. In SF_B, generating units can either connect to AC grids or DC grids. In addition, the AC grids and DC grids will be connected to each other via power converters. These power converters will have their own controllers and will participate in frequency control.

Like the case of SF_A, SF_B will also have RoCoF units to capture the changes in frequency following a disturbance. The RoCoF measurements will also be transmitted from the RoCoF units to the plant RTUs. However, the communication required may be faster since there is no inertia in the power system and the frequency changes very fast. Provisions for maximizing the trade-offs between frequency measurements and frequency estimations should be made.

The high penetration of RES in the medium-voltage and low-voltage DC grids may give several DSOs their own supervisory control to implement secondary control. This has been discussed in [10], showing that the active power management distributed resources and demand-side response will be helpful in maintaining frequency balances and help in solving congestions in both transmission and distribution networks. Nevertheless, aggregators will still have a role for the aggregation of small RES and ESS in the low-voltage grid.

Furthermore, the concept of LSD will be used for frequency control in SF_B. At the moment, LSD's application for frequency control is still being developed in WP2. LSD's application in frequency control will be described in D2.3 that is due on Month 18 of the project. This deliverable presents the latest versions of the component and functional requirements in SF_B at the moment of writing. However, these requirements may change depending on future research developments in WP2.

3.2 Frequency Control Requirements placed on Power Systems

The changes from the present power system to the power system in SF_A and SF_B require future frequency control to accommodate the new RoCoF control and faster primary and secondary controls. Further research in frequency control may also lead to new control stages for the future.

Table 2 lists the requirements placed on power systems to enable frequency control in SF_A and SF_B. These requirements must be validated with the field tests that will be conducted during the project.

Table 2. Component and functional requirements for frequency control

SF_A	SF_B
Component Requirements • Hydro, storage-connected solar plants, and wind plants • Power converters • Energy Storage Systems • Tie Lines • Loads • Local Meters • Local Controllers • Remote Terminal Units • RoCoF units • Supervisory Controller (of TSO)	Component Requirements • Storage-connected Solar and wind plants • Power converters • Energy Storage Systems • Tie Lines • Loads • Local Meters • Local Controllers • Remote Terminal Units • RoCoF units • Supervisory Controller (of TSO)

• VPP Controller (of DSO or Aggregator) Functional Requirements (ensured by TSOs)[1,2] • RoCoF control (decentralized or distributed) • Primary Control (decentralized or distributed) • Secondary Control (centralized)	• VPP Controller (of DSO or Aggregator) • DC grids • Power-converters interfacing DC grids and AC grids Functional Requirements (ensured by TSOs and DSOs) [1,2] • RoCoF control (independent or coordinated) • Primary Control (independent or coordinated) • Secondary Control (centralized) • Additional control stages are still possible

[1] *RoCoF, primary, and secondary control in SF_B will have shorter timeframes.*
[2] *In D1.3, independent control is called decentralized control, while coordinated control is called distributed control.*

The requirements are discussed as follows:

3.2.1 Component Requirements

a) **Generating Units** [11]**:** 1) Hydro Plants use electric power to produce electricity. Water storage can serve as an ESS as well as a means to regulate the flow of water. 2) Storage-connected Solar Plants: Solar plants convert electricity from energy radiated by the Sun. The solar plants considered in SF_A and SF_B are equipped with ESS, allowing them to provide frequency control support. 3) The wind plants are groups of wind turbines interconnected to a common utility system that converters wind power to electricity. These wind plants can provide frequency support through by changing the angles of the turbines' blades.

b) **Power Converters:** The power converters provide the interface between the grid and the different RES and electrical ESSs. The power converters will provide AC to DC, DC to DC, or DC to AC conversion. These converters must be able to handle the high-power transfers required in RoCoF control.

c) **Energy Storage Systems (ESSs):** ESSs will release stored energy to provide support in the RoCoF, primary, and secondary control stages.

d) **Tie Lines:** Tie lines provide interconnections between different transmission grids. The use of tie lines will help maximize the utilization of available capacities from future RES and ESSs.

e) **Loads:** Loads consume electric power. Adjustable loads are considered for load demand response and load shedding. They must be suited with specific communication and automation equipment.

f) **Local Meters:** Each generating unit must include a meter that will provide frequency measurements.

g) **Local Controllers:** Each generating unit must have a local controller. Today, these local controllers house the primary control function, and perform it independently from one another. In both SF_A and SF_B, the local controllers will also house the RoCoF control.

h) **Remote Terminal Units (RTUs):** Each generating unit must include an RTU. In SF_A and SF_B, the RTUs relay the following information:

   - frequency measurements from local meters to local controllers
   - frequency measurements from local meters to RoCoF units
   - control commands from RoCoF units to local controllers
   - frequency measurements from local meters to supervisory controllers, microgrid controllers, or aggregators

- control commands from a supervisory controller or aggregator to the local controllers

i) **RoCoF units:** RoCoF units participate in distributed RoCoF control. In distributed RoCoF control, a RoCoF unit performs frequency measurements, frequency estimation, and RoCoF calculation. It sends control signals to the different controllers to adjust the power outputs of different generating units and ESSs.

j) **Supervisory controller:** A control unit that houses the secondary control function.

k) **VPP controller:** A control unit that facilitates the coordinated operation and response of aggregated units covered by the VPP.

l) **DC Grids:** Transmission or distribution segments of the power system that uses DC voltage.

3.2.2 Functional Requirements

a) RoCoF control:

i) **Objective:** Supply synthetic inertia to the power system following a disturbance to slow down the frequency dynamics.

ii) **Equipment rating:** The power plants and ESSs should be capable of releasing energy fast enough to provide enough synthetic inertia to the power system right after disturbances to limit the rate of change of frequency. In this regard, SF_B requires higher power generation from the storage elements as compared to SF_A.

iii) **Timeframe:** For SF_A, the research work assumes that the required timeframe for RoCoF control is from the beginning of fault up to 5 seconds. This timeframe includes the time needed for measurements and communications. Future field tests of the project need to evaluate the appropriateness of this timeframe. For SF_B, the researchers expect the required timeframe for RoCoF control is shorter compared to that of SF_A. One reason for the reduction in control duration is the faster response required by the faster dynamics due to the absence of inertia from generation. Another reason is that the power converters can provide control faster than the regulation provided by synchronous machine controllers. The exact timeframe for RoCoF control in SF_B will be defined later in the project as work in WP2 continues. In SF_A and SF_B, the total response time for the control must be minimized.

iv) **Frequency Measurements and Estimation:** Trade-offs between local frequency measurements and frequency estimation must be in place to maximize the benefits of RoCoF control.

v) **Accuracy of Frequency Measurements:** Meters and RoCoF units must have accuracy and granularity that are high enough to capture the fast changes in frequency after the disturbance. The numbers must be determined as research in WP2 continues.

vi) **Manner:** The controllers may perform the RoCoF control in a decentralized manner (i.e. individually based on local measurements and without the use of communications). The controllers may also perform the RoCoF control in a coordinated manner (with communications with other controllers and RoCoF units).

vii) **Coordination Requirements:** In case used, communication infrastructure must be fast enough to allow RoCoF control.

b) Primary control

i) **Objective**: Contain the frequency within the allowed range and stabilize it on a certain quasi-steady state value

ii) **Maximum deviation of quasi-steady-state value:** Like the present case, primary control in SF_A and SF_B should stabilize the frequency to a level that falls within the maximum permissible deviation of the steady state-value. The present value (± 180 mHz for Central Europe) in network codes must be reviewed if more stringent limits must be in place in the future. In SF_B, the limits may become less stringent, as the loads and generating units affected by grid frequency becomes fewer.

iii) **Maximum instantaneous frequency deviation:** Primary control, together with the RoCoF control, should limit the instantaneous frequency within the maximum and minimum limits set by network codes. The current limits must be reviewed if more stringent or less stringent limits need to be in place in the future. If faster control is envisioned for SF_B compared to that of SF_A, then reserves must be sized accordingly.

iv) **Availability of reserves:** Determination of the appropriate size of reserves available and used in primary control should consider the intermittency of generating units and the presence of ESSs. Availability of primary control reserves must be ensured always. This can be difficult to ensure using the present available technologies. From the technical point of view, it is challenging to reduce the generation of a wind or photovoltaic power plant with 1-2% to provide primary control. For the wind plants, it is the possibility to change the angle of the wind meal pales but this is not accurate and it is not fast enough to provide primary control when needed. For the photovoltaic plants, it is even more complicated and the most convenient solution is to use USS

v) **Reliability:** Primary control is expected to work without the need for automatic load-shedding or disconnection of generation in response to a frequency deviation.

vi) **Accuracy and measurement cycle of frequency measurements:** The accuracy and granularity of frequency measurements must be high enough to capture the fast dynamics of the power system. The present accuracy requirement (e.g. 10 mHz for Central Europe [12]) and measurement cycles (typically 0.1 seconds to 1 second for Central Europe [12]) from network codes must be reviewed to check if they are appropriate for the future systems with faster dynamics.

vii) **Manner:** The controllers may perform the primary control in a decentralized manner (i.e. individually based on local measurements and without the use of communications). The controllers may also perform the primary control in a coordinated manner (with communications with other controllers).

viii) **Controller sensitivity**: Like SF_A, the controllers must be sensitive enough to handle the faster changes in frequency. The present sensitivity requirements from network codes (e.g. 10 mHz for Central Europe) must be reviewed if they are still appropriate for future power systems

ix) **Time to deploy reserves:** In cases where RoCoF control is not able to limit the RoCoF up to a certain value, then primary reserves will be deployed sooner following a disturbance. The maximum deployment time required by network codes (e.g. 30s for Central Europe [12]) needs to be reviewed. Due to the anticipated faster response in SF_B, the maximum deployment times of primary reserves in SF_B will be shorter comparted to that in SF_A.

x) **Responsibilities in the process:** Both TSOs and DSOs may play an active role in the ensuring that generating units can perform primary control. This role is currently done by the TSO. However, the proliferation of RES in the distribution level may require the DSO to ensure that this requirement is met in the future.

xi) **Information exchange between TSOs/DSOs:** Contribution of each connecting TSO, or DSO, must be reviewed to account the intermittency of generation and the presence of ESSs. Changes here will determine the information exchanges required among TSOs and DSOs in the future.

c) Secondary control

i) **Objective:** Restore the frequency back to the nominal value. Also, restore the power exchanges among the transmission grids back to their desired values.

ii) **Secondary controller:** A single automatic secondary controller must perform the secondary control for a control area. The definition of control area and its Area Control Error must be updated for possible cases where DSOs have their own secondary control.

iii) **Secondary controller characteristics:** Measurement cycle times, integration cycle times, and controller cycle times must be coordinated within the control loop. The required control cycle time must be reviewed to check their appropriateness to the expected frequency dynamics.

iv) **Manual control capability:** Like today's requirement, manual control of reserves must be allowed in case of deficiencies in the automatic secondary control

v) **Secondary control reserve:** Secondary control reserves must be available to cover the expected fluctuations in demand and generation. Reliability criteria, intermittency of solar and wind, and the presence of ESSs must be considered when determining reserve requirements.

vi) **Availability and Reliability of the Control Function:** Like today's requirement, the operation of the automatic secondary controller should be on-line and closed-loop. The controller must have a very high availability and reliability, with a back-system ready to take over the control action in case of outage or fault in the automation system providing secondary control [12]. Reliability of measurement transmission to the secondary controller must also be reliable (e.g. using parallel data links).

vii) **Metering and Measurement Transmission to other TSOs/DSOs:** Usage and provisions for alternative measurement from neighboring control areas for comparisons and eventual backup must be in place. Required interactions among DSOs and TSOs to ensure an effective secondary control must be in place.

viii) **Data Recordings:** Recordings of all values required for the control action of the secondary controller and for analysis of normal operation and incidents in the interconnected power systems. These values include frequency measurements, active power flows, and exchange set-point value.

3.3 Implementation and roll-out outlook for the scenarios in frequency control

3.3.1 SF_A

The implementation of SF_A will involve adaptations, reconstructions, evolutions, and revolutions.

a) Adaptation - Typically, power systems are in the “Adaptation” mode, accommodating incremental changes in demand growth, technology change, and consumer preference.

b) Evolution - “Evolution” implies fundamental changes to power system technologies and actors, albeit over a relatively long period of time and through sustained incremental change.

c) Reconstruction - “Reconstruction” implies rapid change but without fundamental changes in power system actors or technologies.

d) Revolution - “Revolution” implies rapid fundamental changes across power systems.

Adaptations in SF_A include the use of HVDC links to connect different transmission systems and the development of the European Supergrid. Adaptations also include network reinforcements that will allows power transfer from locations with high potential of solar and wind to areas where the loads are located.

Reconstructions in SF_A include new market and market rules that must be adopted to enable the energy resources needed by future automation systems to control frequency effectively.

Evolutions in SF_A includes the proliferation of electronic based loads, and the decreasing meaning of frequency to the operation of loads. For example, in households, the only loads that are affected by frequency are refrigerators and washing machines. However, some of these will soon be fitted with power converters, eliminating the effect of frequency to the device' operation. In industries, the induction machines are gradually fitted with power converters for their controlling their operations, thus decoupling more loads from the effects of the grid frequency.

Revolutions in SF_A include the development of storage systems and flywheels. Researchers in WP2 expect these technologies to be available within 5 to 10 years, considering the actual state-of-the-art of technology. The development of a standard for frequency measurements is also a revolution in the power system. This includes the new metering and data processing hardware needed to capture the fast RoCoF due to reduced mechanical inertia.

The researchers in WP2 expect the control architectures in SF_A to be used in real power systems within 10 to 30 years from now, depending on the proliferation of different generation and ESSs technologies.

3.3.2 SF_B

The adaptations, evolutions, reconstructions, and revolutions in SF_A are also expected to happen in SF_B. However, compared to the roll-out of SF_A, the roll-out of SF_B is expected to happen in fewer countries. The roll-out of SF_B is expected to happen in countries where there are no hydro or geothermal resources (e.g. Germany). Countries with hydro and geothermal capacities are likely to utilize those resources for power generation. These countries are not likely to have the situation described in SF_B.

SF_B is likely to roll-out later than SF_A. The reasons include the following:

a) Faster response required from power generating units, ESSs, and power converters.

b) Additional responsibility of DSOs to provide frequency control.

Due to faster frequency dynamics in SF_B, the ESSs and power converters in SF_B needs to respond faster compared to those in SF_A. Also, the total power capacity requirement of ESSs in SF_B is also higher compared to that in SF_A. This because arresting faster frequency dynamics needs faster release of energy from storage systems. This can be achieved by having more ESSs in the power system, or, by having ESSs and power converter technologies that allow faster injection of electric energy to the grid. The roll-out outlook of SF_B depends on the development and availability of these technologies.

The roll-out outlook of SF_B also depends on how the DSO responsibilities for frequency control will change over time. DSOs engagement in frequency control requires new network codes to be in place.

3.3.3 Implementation at the low-voltage level

Generating units, storages, and loads connected at the low-voltage contribute little to frequency control if they act individually. However, when they coordinate with each other through VPPs or microgrids, then they can act as one aggregated unit that can provide services to support frequency control. The frequency control concepts in both SF_A and SF_B consider the aggregated units connected to the low-voltage grids. However, implementing the aggregation also requires controllers at the customer premises for inertial and primary control, and communication links to the VPP or microgrid controller so the units can participate in secondary control. This requirement further increases the number of communication and control endpoints in the power system, and further challenges the ICT system to provide a reliable and secure automation system that will enable the participation of distributed RES.

3.4 Support needed from Emerging Actors

Emerging Actors are the key figures leading the changes in the electric grid. A lot of their future characteristics and potentialities depend on the business and regulation environment. Energy

Authorities and System Operators should facilitate the deployment of new efficient services and possibilities by changing the market structure and the network codes.

RESERVE will propose how such changes could be formulated, considering the maximum market potential and technical efficiency for the power system. Definitions of actors' characteristics and potentialities will be drawn following the indications coming from the simulations and field trials and taking into consideration Corporate Social Responsibility elements in the business model formulation. At this level, it is important to identify what and how Emerging Actors can support the roll-out of the new Frequency and Voltage Scenarios envisioned in the RESERVE.

In SF_A we expect **Bulk Storage Operators** to be the main new actor needed to assure grid stability. These Storage resources will be present mainly in the transmission system, but also in the distribution grid. New power intensive storages (like batteries and flywheels) will presumably be quite big in installed capacity and power rating and the ownership should go to new private stakeholders considering the requirement for the system operators to not possess any sort of active power generating and consumption unit. Accordingly, grid codes should be developed for the **TSOs** and DSOs to operate such resources under specific emergency scenarios, mainly for the grid security reasons. Market mechanisms should be designed also to incentivize the installation of such devices to a suitable percentage and allow the stakeholders to recover their investment as well as get profits during the operation of the power system.

On the other hand, formations of the **Virtual Power Plants** and **Aggregator** is needed to gather the following resources:

a) Distributed renewables generation

b) small cold reserve units

c) demand side resources

The aggregation of these resources will provide ancillary services, especially for the flexibility requirements of the power system, such as reserve, power balance, voltage problems, etc. Similarly, clear grid codes should be developed for the power system operators to mobilize these resources, in terms of issuing the requirements and the corresponding acquisition. Markets should be setup for trading such flexibility in a longer time framework, maybe similar to the time frame of current secondary load-frequency control and tertiary control. Regulatory framework should be defined to allow such kind of transactions and participations in the markets.

Both SF_A and SF_B should take care of the special needs coming from the **HVDC lines** which could connect different countries without the need of synchronization. TSOs will have to coordinate between each other to manage these special lines. In SF_B the possible presence of hybrid AC/DC power systems will increase the need for more coordination. Stronger forms of TSO-DSO coordination could be envisioned.

In SF_B, all the prerogatives and changes in SF_A can surely be found but with more stringent requirements and needs.

In SF_B, **DSOs** should operate under new rules and codes which defines their actions in case generating units connected to distribution systems are causing stability problems. In the past, these problems were usually solved by TSOs at the transmission level by the power system inertia and further by dispatching commands or by dispatching service markets. In the future, the DSOs will certainly have new roles and new responsibilities; however, it is uncertain if local markets driven by DSOs will be created or just some verification and corrective actions will be needed by DSOs to operate the distribution system, in cooperation with the TSOs.

Retailers will have to find their new roles to play in such new scenario to survive, where individual **prosumers** will have much more freedom and will change drastically their behaviors. While big prosumers will have the expertise and knowledge to optimize their energy behaviors, it could be considered normal that small households and commercial activities could benefit from a retailer who decide and optimize the behavior of the clients, maximizing their economic output and charge services fees. In this sense future retailers could become more like **Prosumers Service Providers** and will appear not just in the energy market, but also in the market for Ancillary Services. Their behavior could be somewhat like a Load Aggregator even if differences with respect to technical or commercial responsibilities could be found. Depending on simulation results the two figures could be maintained or joined into one.

The new structure will have massive new communications to maintain the whole chain of new operations envisioned in the RESERVE projects. Thus, the communication architecture and the provided services will become critical to assure the operations of the power system. Therefore, responsible actors should be decided with clear operational codes. The TSOs and DSOs are the natural choice for this task, but new actors could be emerged as well. For example, to manage dedicated hardware and software structures the Communication Services Providers can be created. Requirements from all stakeholders of the grid could be set and fixed and transferred to the communication services providers which will be payed for their services and investments.

3.5 Summary

To summarize, future control systems must deal with faster frequency dynamics. Scenario SF_A has faster frequency dynamics than the present scenario because there of the reduced share of generation from synchronous machines. SF_B has even faster frequency dynamics compared to SF_A. This is because there are no synchronous generation in SF_B that will provide rotational inertia.

Due to the faster frequency dynamics, future frequency control systems require a new control function called RoCoF control. The RoCoF control provides synthetic inertia to the power system. In SF_A, The RoCoF control needs to happen right after the fault up to 5 seconds. A shorter time-frame will be adopted in SF_B.

The RoCoF control may be implemented though the independent action of individual local controllers in the power system. In this case, RoCoF control will be based on local measurements. RoCoF control may also be implemented through RoCoF units giving control commands to the different local controllers that performs the control in a coordinated way.

Meters, local controllers, communication infrastructure must be fast enough to enable RoCoF. Also, future network codes and standards must be written for RoCoF control, including standards for frequency measurements.

Like the present scenario, the future frequency control systems will also implement the primary and secondary controls. The intermittent RES also pose challenges for ensuring enough reserves for primary and secondary control. Future automation systems must be able to use the intermittent reserves from RES and take advantage of ESSs.

In SF_B, frequency control will use the concept of Linear Swing Dynamics (LSD). As the research work in WP2 develops, the control architecture used in SF_A may change. That is, new control stages may be defined in addition to the RoCoF, primary, and secondary control stages. If in case LSD will adopt the RoCoF, primary, and secondary control stages, then the time frames will be shorter compared to those used in SF_A.

Although not the focus of the research work in WP2, future automation systems must also allow the aggregation of distributed RES and ESSs at the low-voltage levels. ICT infrastructures, regulations, emerging actors, and market rules supporting the aggregation must also be in place.

The roll-out of SF_A and SF_B will involve incremental and sudden changes from the present scenario.

The gradual changes include adaptations in the increased use of HVDC links and the development of a European Supergrid. The gradual changes also include the evolution of the grid towards a more RES-based generation and converter-interfaced loads.

The sudden changes include reconstructions in the form of electricity market developments and new marker rules. These changes also include revolutions in the development of ESSs and new standards for frequency measurements.

Support from emerging actors is also needed to put the requirements in place. These actors include bulk energy operators, virtual power plants, aggregators, retailers, and prosumers. TSOs and DSOs will also have new rules and codes to follow for future frequency control.

4. Voltage Control Scenarios and Requirements

4.1 Scenarios considered in Voltage Control

4.1.1 Present Scenario

Today, voltage control maintains the voltages' RMS values within their acceptable limits. The RMS values could go beyond their acceptable limits due to the following reasons [13]:

a) sudden changes in the power consumption of electrical loads in the power system; and

b) sudden loss of reactive power supply.

The present voltage control corrects voltages' RMS values using the following power system devices:

a) Automatic voltage regulators (AVRs) of synchronous machines

b) Shunt capacitor banks

c) Shunt reactors

d) On-load tap-changing (OLTC) transformers

e) Flexible AC Transmission System (FACTS) controllers

These devices participate in voltage control as follows:

a) AVRs of synchronous machines adjust the machines' reactive power generation or consumption.

b) Shunt capacitors increase or decrease their reactive power generation.

c) Shunt reactors increase or decrease their reactive power consumption.

d) Each OLTC transformer adjusts the voltage ratio between its windings.

e) FACTS controllers use power electronics to generate or consume reactive power.

The present architecture of voltage control has three levels of hierarchy [14]. These levels are the primary, secondary, and tertiary voltage controls.

The primary control is the first step in the hierarchy. In the primary control, each participating device act independently from one another. Here, each device corrects the RMS value of the voltage at its connection point to the power system. However, this may also lead to higher power system losses. This could also cause voltages in the other parts of the power system to have unacceptable RMS values.

The secondary control addresses the problems that the primary control may cause. The secondary coordinates the different participating devices. This involves the use of a centralized controller and communication systems.

Tertiary control optimizes the voltage set points used in the secondary control. The optimization process accounts the economic aspects of the problem such as cost and efficiency.

In RESERVE, two future scenarios for voltage control are investigated. These scenarios are the SV_A scenario and the SV_B scenario. These scenarios focus on the distribution network, where numerous RES, ESSs, and electronic loads are expected in the future.

4.1.2 SV_A: Dynamic Voltage Stabilization

The first scenario studied for voltage control is the SV_A scenario. In the SV_A scenario, we propose the use of Virtual Output Impedance (VOI) control. VOI control will maintain dynamic voltage stability in future power systems. The present voltage control does not address dynamic voltage stability. The reason is that dynamic voltage stability is not a concern in today's power systems. However, it will be a concern in future distribution networks because of the connection of numerous power converters. Without dynamic voltage stability, the sinusoidal shape of the voltage will be distorted.

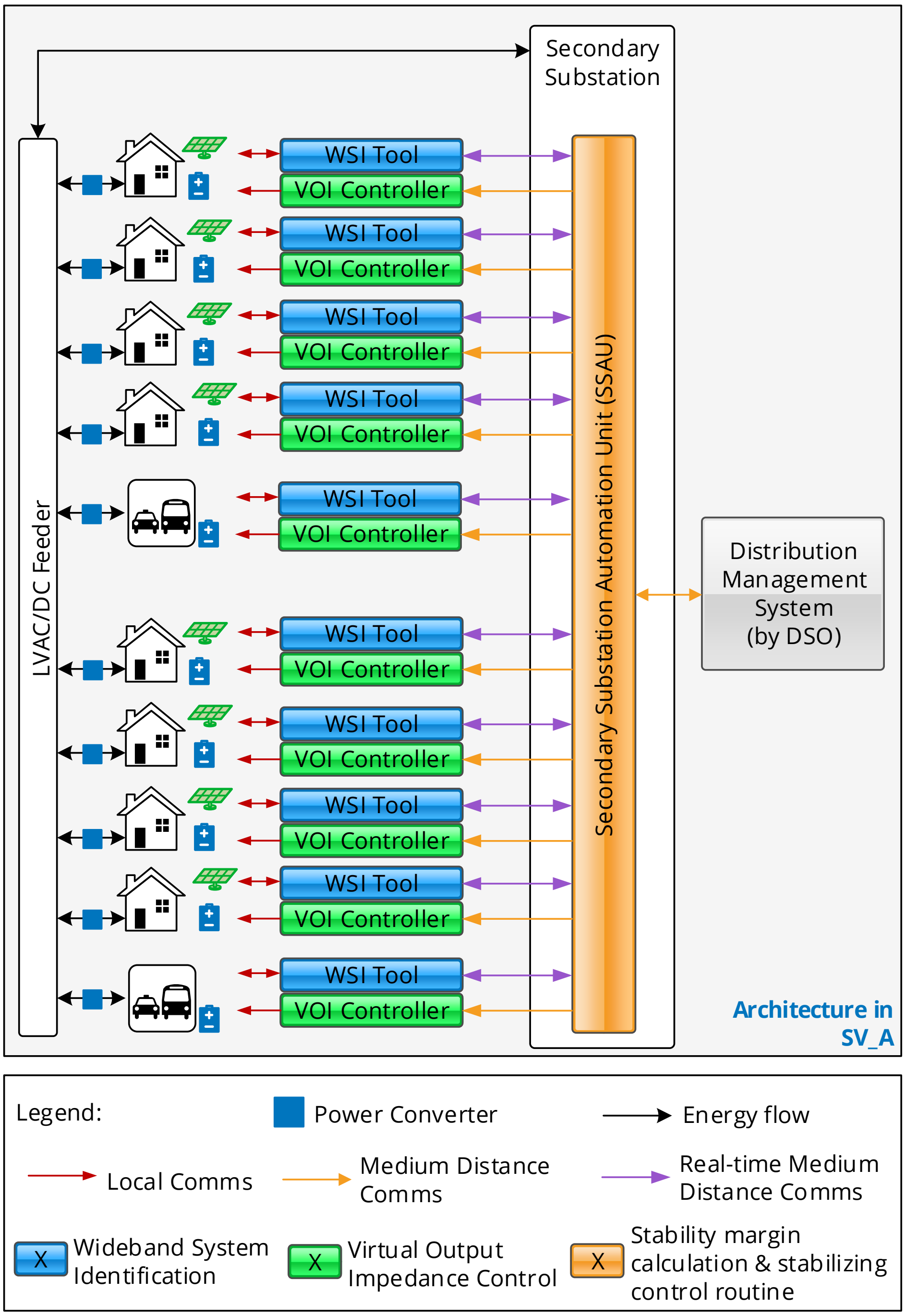

Figure 6. Voltage control architecture in SV_A

From the perspective of the distribution network, a power converter has an output impedance. Moreover, from the perspective of the same converter, the distribution network has a grid impedance. The ratio of these two impedances show the converter's contribution to dynamic instability. The proposed VOI control regularly monitors these impedances. If needed, it also adjusts the converter's output impedance to reduce its contribution to instability.

Furthermore, the proposed VOI control requires the following new functions and components:

a) Functions:

   - Wideband system identification (WSI) that measures the output impedance of the power converters

- Stabilizing control routine that calculates the desired output impedances of the converters
- Virtual output impedance (VOI) control function to modify the converter output impedance if needed

b) Components

- WSI Tool that performs the WSI function
- Secondary Substation Automation Units (SSAUs) that performs the stabilizing control routine
- VOI Controller that performs the VOI control function.

Figure 6 shows the listed requirements in a schematic diagram. Here, power converters provide the interface between the distribution network and each load. The distribution network supply energy to residential customers and electric vehicle (EV) charging stations. Furthermore, the residential customers and EV charging stations have their own RES and ESSs. This allows them to supply energy back to the distribution network.

In the proposed VOI control, each power converter has a WSI Tool and a VOI controller. Both could be placed inside the converter. And so, both use local communications to communicate with other converter components.

The WSI Tool performs the Wideband System Identification function. This function determines the converter impedance and the grid impedance. It communicates with the SSAU via a real-time medium-distance communication link. The real-time communication allows accurate stability evaluation.

After it receives the impedances from the WSI Tool, the SSAU performs the Stability Margin Calculation. It calculates the stability margins in the power system using the ratio of the impedances. The resulting stability margins determine the next step of the SSAU, which is one of the three cases below.

- Case 1: The margins are acceptable. Here, the SSAU does no control action. Then it proceeds to check the other converters in its coverage.
- Case 2: The margins are critically low. Here, the SSAU alarms the DSO via the Distribution Management System (DMS). To maintain stability, the DSO could disconnect the converter from the network.
- Case 3: The margins are low but not within critical levels. Here, the SSAU performs the Stabilizing Control Routine. It produces the desired output impedance of the converter to maintain stability. After that, the SSAU sends the desired output impedance to the VOI controller of the converter. Then, the VOI controller adjusts the output impedance of the converter accordingly.

The following steps illustrates the steps needed to perform VOI control [D3.1]:

1. The *SSAU* commands a WSI Tool (*WT1*) to perform WSI.

2. *WT1* performs WSI by making its power converter (*PC1*) inject noise into the network. The injected noise is a pseudo-random binary signal (PRBS). This noise should not violate future requirements in power quality.

3. *PC1* senses the changes in the voltage and the current at its connection point to the network. It sends information about these voltage and current back to *WT1*.

4. Based on the information from *PC1*, *WT1* determines the output impedance of converter *PC1*. Then, *WT1* sends the value to the *SSAU*.

5. The *SSAU* commands a neighboring WSI tool (*WT2*) to make its converter (*PC2*) inject another PRBS into the network.

6. The noise propagates naturally to the connection point of *PC1* to the network.

7. *PC1 senses the changes in the voltage and the current at its connection point. It sends information about this voltage and current to WT1.*

8. Based on the information from *PC1*, *WTI1* will determine the grid impedance.

9. *WT1* sends the grid impedance to the SSAU,

10. Based on the converter output impedance from (4) and grid impedance from (9), the SSAU calculates the stability margins of the power system.

11. Based on the margins, the *SSAU* responds with one of three ways:

    i. Case 1: The margins are acceptable. The *SSAU* does no control action. Then it proceeds to check the other converters in its coverage.

    ii. Case 2: The margins are critically low. The *SSAU* alarms the *DSO* via the Distribution Management System (*DMS*). To maintain stability, the DSO could disconnect *PC1* from the network.

    iii. Case 3: The margins are low but not within critical levels. Here, the next steps are as follows:

        1. The *SSAU* performs the Stabilizing Control Routine. It produces the desired output impedance of the converter to maintain stability.

        2. The *SSAU* sends the desired output impedance to the *VOI1* controller of *PC1*.

        3. *VOI1* adjusts the output impedance of *PC1* accordingly.

12. Steps 1 to 11 is repeated until stability margins are calculated for all power converters in its coverage.

4.1.3 SV_B: Active Voltage Management

The second scenario for voltage control is SV_B. In SV_B, we propose an active voltage management scheme. This scheme has the same objective as today's voltage control. However, instead of using additional power system components such as OLTC or shunt capacitors, the proposed scheme will use the power converters available at the customer premises. With this scheme, DSOs do not need additional investments to maintain the RMS values of the voltage within acceptable limits.

Dynamic voltage stability is not the only concern in distribution networks with distributed RES and ESSs. Present voltage management systems are also likely to fail in the presence of RES penetration levels envisioned in the RESERVE project. Present voltage control systems to do not facilitate a voltage drop anticipated with 100% RES nor do they allow for the constraint breaches possible due to volt-rise effects of generation on distribution systems.

To address this issue, the research work in SV_B envisions a new voltage management scheme. Figure 7 shows the difference between how voltage management is done today on how is it envisioned in SV_B.

The improvements that SV_B is aiming to implement is the installation of a control architecture for converter-based RES connections on distribution systems. Such a control system will accommodate an RES connection on the most electrically distant point on LV feeders while also facilitating connections on MV that exhibit altogether closer electrical proximity.

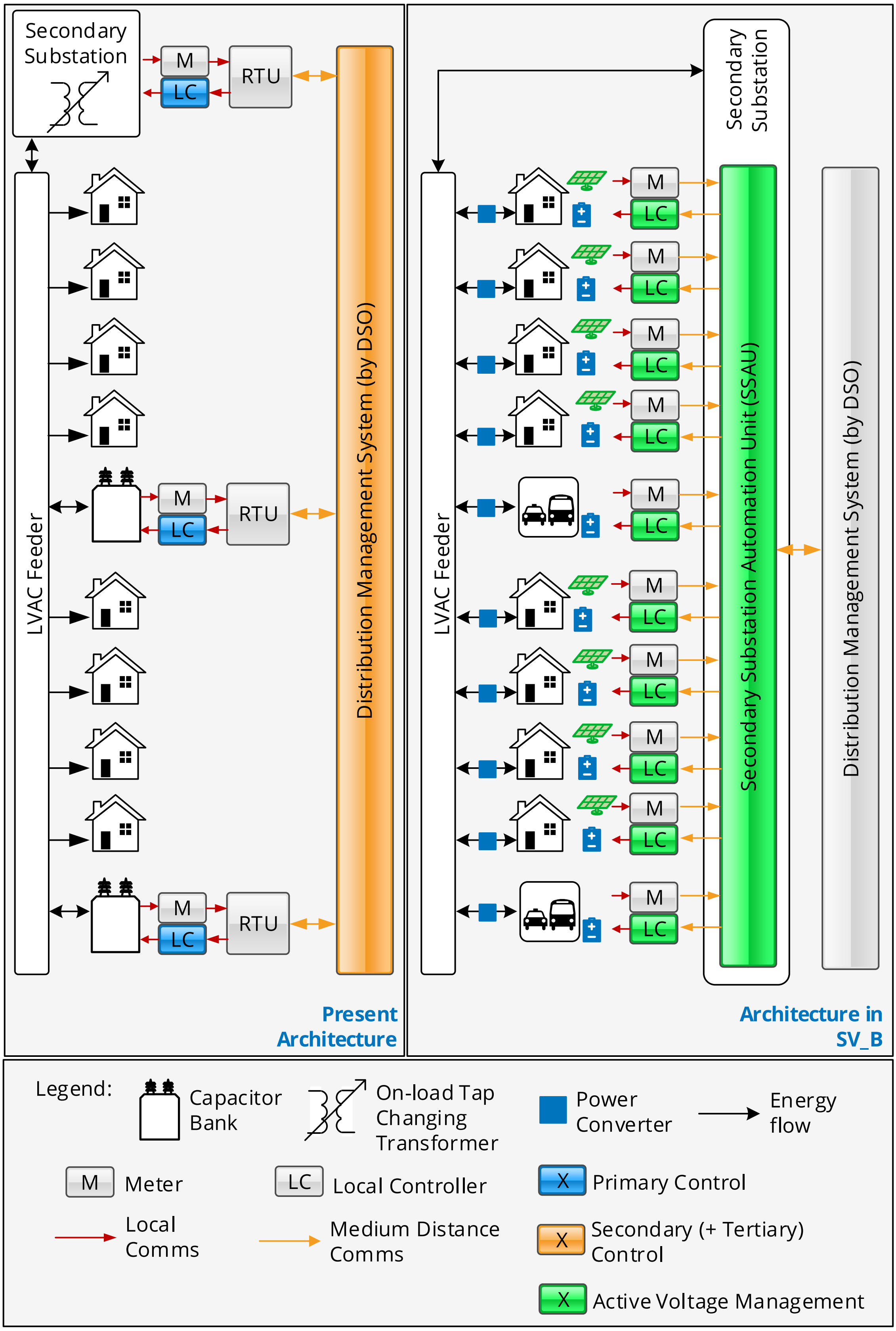

Figure 7. Voltage control architectures today and in SV_B

The Active Voltage Management (AVM) approach proposed here reduces the problem to a local objective for each RES unit: to target a single voltage value and to maintain a relationship between the reactive power provided and the voltage observed: known as a volt-VAr curve.

The volt-VAr curve is the output of an offline optimization procedure. In the proposed method, the DSO performs the optimization based on historical power profiles of RES and customers and not on real-time values.

To adhere to these optimally fit volt-VAr curves, the voltage at the terminals of the RES and the present reactive power capacity will be communicated to SSAU where corrective action can be calculated.

4.2 Voltage Control Requirements placed on Power Systems

Based on the foregoing discussions, the requirements for automation systems to maintain dynamic voltage stability and perform active voltage management are summarized in this section.

Table 3 summarizes the component and functional requirements for voltage control in SV_A and SV_B.

Table 3. Component and functional requirements for voltage control

SV_A	SV_B
Component Requirements • Power Converters • Local controllers with WSI Tool and VOI Controller • SSAU • Distribution Management System Functional Requirements (Ensured by DSOs) • WSI • VOI Control • Stability Margin Calculation • Stabilizing Control Routine • DSO's Manual Corrective Action	Component Requirements • Power Converters • Local Meters • Local Controllers • SSAU Functional Requirements (ensured by DSOs) • Optimized Curve Selection • Curve Implementation

More details about these requirements are discussed in the following subsections. Unlike in scenarios in frequency control, the scenarios in voltage control are solving two distinct problems. Thus, the requirements for two scenarios are discussed in separate subsections.

4.2.1 SV_A

Future automation systems require the following items to maintain dynamic voltage stability in future distribution systems:

4.2.1.1 Component Requirements:

a) **Power Converters:** The power converters provide the interface between the grid and the different RES and electrical ESSs. The power converters will provide AC to DC, DC to DC, or DC to AC conversion.

b) **Local controllers with WSI Tool and VOI Controller**: The power converters should include a WSI Tool and a VOI controller. Both can stay on the enclosure with the local controller. WSI tools will house the WSI function, while the VOI controller will house the VOI control function.

c) **SSAU:** The SSAU stays at the secondary substation and house different control and automation functions for the DSO. For SV_A, it will both house the Stability Margin Calculation and Stabilizing Control Routine.

d) **Distribution Management System:** This system supports the decision making of personnel in the field and control room of the DSOs.

4.2.1.2 Functional Requirements

a) **WSI:** The WSI tool must be able to make the power converter inject a pseudo random binary signal (PRBS) to the power system, allowing the WSI itself to measure or calculate the converter output impedance and parametric impedance. The researchers envision a 1-hour monitoring cycle per power converter.

- **Compliance with Power Quality Standards:** The WSI process needed for impedance measurements will affect the harmonic distortion in the power system and voltage flicker. Therefore, the process must comply with the network codes on power quality. An example standard related to this is Distribution Code from ESB [15].

b) **VOI Control:** Upon receiving instructions from the SSAU, VOI controllers must be able to adjust the output impedance of the power converters to maintain the desired stability margins of the power system.

c) **Stability Margin Calculation:** The Secondary Substation Automation Unit (SSAU) must receive the impedance information from the WSI tools as soon as possible. The SSAU is responsible the stability assessment of the power system based on the impedances. It sends signals to the VOI controller or to the DMS depending on the results of the stability assessment.

- **Provisions for stability margins:** Future network codes must contain provisions about the required stability margins (gain and phase) in the power system.

d) **Stabilizing Control Routine:** This is a function done by the SSAU to calculate the desired output impedance of a converter to maintain the desired stability margins.

e) **DSO's manual corrective action:** This is not done by the automation system, but it plays a role for maintaining dynamic stability. In cases where the stability assessment from the SSAU shows an unstable situation, then the DSO must perform corrective action through the DMS.

4.2.2 SV_B

To perform active voltage management in future distribution systems, future automation systems require the following items:

4.2.2.1 Component Requirements:

a) **Power Converters:** These are the same converters used in SV_A.

b) **Local Meters:** These meters measure the RMS value of the voltage and current at the connection point of the converter and the distribution system. These meters also provide the real and reactive power consumption or generation flowing through the converter.

c) **Local controllers**: These are the same controllers used in SV_A, but without the need for WSI Tools or VOI controllers.

d) **SSAU:** The SSAU stays at the secondary substation and house different control and automation functions for the DSO. For SV_A, it will both house the Optimized Curve Selection Function.

4.2.2.2 Functional Requirements

a) **Optimized Curve Selection:** For each converter, the SSAU will select an appropriate Volt-VAr curve to use. The selection will be based on the objective set by the DSO, which can be to minimize losses or cost. Some remarks about the functional implementation are as follows:

- **Coordination with the present voltage control devices:** During the transition from the present scenario to converter-based feeder in SV_B, the control actions of converters, OLTC, shunt devices must be coordinated ensure they will not reduce the effectiveness of each other.

- **Reactive power injection or consumption of RES or ESSs:** Future network codes must contain provisions on the required reactive power generation or consumption of converter-based RES or ESSs. This means that the power factor of RES should be allowed to be leading or lagging. In the section DCC6.9.1 of ESB Networks Distribution code [15], customers can operate between 0.9 to 1 when drawing power, and between 0.95 to 1 when injecting power. The same section specifies that wind generators must have a power factor between 0.92 and 0.95 lagging. These present requirements assume that the loads and their RES or ESSs only consume reactive power. However, RES or ESSs should be able to provide reactive power in the future to provide voltage control. This means that the current limits must be relaxed and allow RES, ESSs, and converter interfaced loads to operate at a leading power factor.

- **Optimized Volt-Var curves:** The DSO must derive and provide optimized volt-VAr curves for each participating power converter. These curves will not only ensure that voltages in the power system are within acceptable values, it could also improve the power system efficiency by optimizing power losses, improve the load balancing among the different phases of the AC system, and minimize operation cost. Different volt-VAr curves will be required for different optimization objectives. The optimization must not lead to violation of thermal constraints of lines and transformers in the power system

b) **Curve Implementation:** Each power converter receives its own curve. Each local controller follows this curve for regulating the voltage and reactive power injection or consumption of the converter.

4.3 Implementation and Roll-out Outlook

The researchers expect a gradual change from the present scenario to the SV_A and SV_B scenarios. For both SV_A and SV_B, the start of the transition will come from the ongoing trend of customers installing RES at the household level. Afterwards, regulations and market forces could drive the participation of RES and their power converters for voltage control. Some of the possible drivers are listed below:

a) The development of market for voltage services will provide incentives for customers with RES who will provide voltage control services. In SV_A, voltage services can be in the form of providing VOI control of the converter. In SV_B, customers can provide voltage services through reactive power injection or consumption.

b) Regulators can require all customers with RES to have power converters equipped with WSI tool and communication links to the SSAU. This will allow operators to perform active voltage management and regularly monitor the dynamic voltage stability of the grid.

c) The formulation of network codes about dynamic voltage stability will provide a basis for converter manufacturers in designing WSI tools and VOI controllers.

The SSAUs hosting the coordinated voltage control also host other distribution automation and smart grid functions necessary for future operations. Thus, there is a high expectation that it will be available in the future in numerous substations.

The researchers in WP3 expect that investigations and results in SV_A and SV_B will be applicable in the next generation power systems (2020+). However, SV_B will most likely be relevant sooner compared to SV_A. One reason is that most of the hardware requirements of SV_B are available of the shelf. Another reason is that the problem that SV_A addresses will occur later in time compared to the opportunity that SV_B addresses.

4.4 Support needed from Emerging Actors

The nature of the voltage problem is more local than global; therefore, the most effective solution to attack voltage stability problems is the distributed control. In the new scenarios of 100% renewable generation systems, the voltage stability and management concepts will involve the distribution grid more than before; therefore, emerging actors will mainly be present in the medium- and low-voltage systems.

Voltage regulation is a local issue and therefore the responsibilities are laying into the Distribution Operators area. The Transmission System Operators have some responsibilities but not so much like the distributors.

At the present, the voltage regulation is not a payed service but is working more like a penalty system. In all European countries, all DSOs are in charge for maintaining the voltage level in the distribution system. They do so using OLTC, shunt capacitors, and shunt reactors.

In both SV_A and SV_B scenario, **prosumers** will be at the center of providing voltage control. Prosumers will equip converters with WSI Tools, VOI controllers, and reactive power controller to change reactive power output or adjust the Virtual Output Impedance of the converters or the grid. The DSOs will, under normal circumstances, measure and control the changes and the impedances by communicating the new values of the converter settings. Depending on the regulatory framework, this support from prosumers for the voltage problem can be then regarded as mandatory participation or voluntary services. Further, corresponding network code and business models should be developed at the distribution grid level. In the SV_A, the new service could be reasonably assumed as technical obligation for the converters to exchange signal with the SSAU; in the SV_B a more voluntary based market structure could be envisioned by regarding reactive power injection and consumption as an ancillary service for which a market could be created.

Prosumer Service Providers could have a role in this environment in facilitating prosumers to access the market for these new services. Prosumer Service Provider would be a surrogate for prosumers in the market. In the new framework of the SV_A and SV_B where communication plays an important role as well, **Communication Services Providers** could enter the business as they do in the SF_A and SF_B.

It is important to take into consideration the diverse natures of prosumers: apart from households (which anyway will have different resources available depending on the location), small distributed generation and EV stations should be integrated into the power system. Standardization both in terms of technical features and operation codes are strongly needed to avoid misbehaviors and conflicts.

These new scenarios (especially for voltage but also for frequency) will involve profound changes both in the regulation, market structure and business models. While TSOs and DSOs will have to devise and enforce new network codes taking in consideration of the emerging roles. It is reasonable to assume that to do so even regulators will have to intervene and clearly state and regulate the nature and the limits of these new actors in the future electric grids.

4.5 Summary

There are two future scenarios studied for voltage control. First is SV_A, which addresses the problem of dynamic voltage stability when there are numerous power converters in the power system. Second is SV_B, which addresses the opportunity to perform active voltage management through the power converters.

SV_A will need converters equipped with WSI tools and VOI controllers. WSI tools will allow future automation systems to monitor the converters' output impedances and grid impedances. This impedance will be used to check the dynamic stability of the power system. These impedances will be used to check the dynamic stability of the power system. The impedances are sent to the secondary substation automation units (SSAU) where stability of the power system is evaluated.

The SSAU should have a stabilizing control routine. The SSAU located in secondary substations should also have a stabilizing control routine. This routine will derive new values for the output impedance of converter in case improvements in stability is needed. In such cases, VOI controllers will adjust the converter output impedance after receiving the new impedance from the SSAU. The monitoring and control cycles must conform to future power quality standards.

In SV_B, future automation systems will need optimized volt-VAr curves for each converter. The corrective action of the controllers will adhere to the curves. Automation systems also need the converters to be allowed to operate with leading or lagging power factors. This will enable the converters to inject or draw reactive power when necessary. The curves must also be coordinated with the operation of classical voltage management devices such as capacitor banks. This will ease the transition from the present scheme to the scheme studied in SV_B.

5. Conclusions

In this document, we have shown the needed components and functions in future automation systems for voltage and frequency control.

The requirements summarized in this document are mostly envisioned, and they are solving problems that do not exist yet in majority of power systems. Therefore, these requirements need to be validated in field trials.

And so, updated versions of these requirements will be provided in D1.5. D1.5 will account the results from live tests and field trials, and the research progress in WP2 and WP3.

While the listed requirements in this document are awaiting field validations, they provide insights on some possible implications to supporting infrastructures considered in RESERVE.

The requirements show that there will be more control endpoints in the grid. Proper operation of each control endpoint, as well as the communication links between them, will play a significant role in securing that future automation systems work.

Also, the requirements in frequency control highlights the need for faster control response. Standards for frequency measurements and fast ICT infrastructures are key to the success of future automation systems in this regard.

The requirements in frequency control also show the need to ensure that energy reserves must be ensured for RoCoF, primary, and secondary frequency controls. The formulation of new network codes and the support from emerging actors should ensure that future automation systems will have access to these reserves.

Moreover, actors such as virtual power plants and microgrids will add value in allowing smaller DERs and ESSs in supporting frequency control. Thus, market mechanisms must ensure that such actors will exist in the future.

Furthermore, voltage control for dynamic voltage stability requires the injection of noise to the power system. The level of noise enough for monitoring grid impedances will have to be determined during the field trials. This noise injection must not compromise power quality more than necessary.

Also, new provisions on network codes must be written to provide guidelines on the required stability margins in the future power systems.

Finally, the use of converters to manage/optimize the voltage RMS and power flows in the grid highlight the need to allow future RES and ESSs to either inject or draw reactive power from the grid. Finally, network codes must allow RES and ESSs to do inject or draw reactive power from the grid.

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7. List of Abbreviations

CAES	Compressed Air Energy Storage
CVPP	Commercial Virtual Power Plant
DSO	Distribution System Operator
ENTSO-E	European Network of Transmission System Operators for Electricity
ESS	Energy Storage System
FACTS	Flexible AC Transmission system
FWES	Flywheel Energy Storage
HVDC	High Voltage DC
ICT	Information and Communication Technologies
LC	Local Controller
LSD	Linear Swing Dynamics
RES	Renewable Energy System
RMS	Root-Mean-Square
RoCoF	Rate of Change of Frequency
RTU	Remote Terminal Unit
SSAU	Secondary Substation Automation Unit
TA	Acceleration Time Constant
TSO	Transmission System Operator
TVPP	Technical Virtual Power Plant
VOI	Virtual Output Impedance
VPP	Virtual Power Plant
WP	Work Package
WSI	Wideband System Identification

8. List of Figures

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Annex

A.1 Implications of the requirements to the present Network Codes

Each country's electricity network is governed by internal codes and regulations to ensure power system stability, security of supply, and safe operation. However, in Europe, increased interconnection between countries and high flows dictated by a regional/ pan-European market, determined the need for EU-wide rules to manage electricity flows. These rules, known as network codes or guidelines, are Commission Regulations containing legally binding rules. They govern all cross-border electricity market transactions and power system operations. This is done alongside the EU regulation on conditions for accessing the network for cross-border electricity exchanges [16].

The European network codes are prepared by the European Network of Transmission System Operators for Electricity (ENTSO-E). The network codes are based on a set of principles, called framework guidelines, which are developed by the Agency for the Cooperation of Energy Regulators (ACER). The codes are submitted back to ACER for its opinion. If ACER deems that the code fulfils its framework guidelines and the EU's internal market objectives, and is fair and balanced, it recommends the European Commission to adopt the code. The Commission studies it and then sends it to an Electricity Cross-Border Committee, made up of specialists from national energy ministries, for an opinion. Once the Committee accepts the draft network code, it is adopted with the approval of the Council of the European Union and the European Parliament.

At the date of this document, the following codes and guidelines have already been adopted:

d) Guideline on capacity allocation and congestion management (in force since August 15th, 2015) - Commission Regulation (EU) 2015/1222;

e) Network code on requirements for grid connection of generators - NC RfG (in force since May 17th, 2016) - Commission Regulation (EU) 2016/631;

f) Network code on demand connection - NC DCC (in force since September 7th, 2016) - Commission Regulation (EU) 2016/1388;

g) Network code on Requirements for grid connection of high-voltage direct current system and direct current-connected power park modules - NC HVDC (in force since September 28th, 2016) - Commission Regulation (EU) 2016/1447;

h) Guideline on forward capacity allocation (in force since October 17th, 2016) - Commission Regulation (EU) 2016/1719.

i) Guideline on electricity transmission system operation (in force since August 2nd, 2017) - Commission Regulation (EU) 2017/1485.

The following codes and guidelines are in the process of approval:

j) Balancing Guideline;

k) Network code on emergency and restoration;

l) System Operation Guideline.

The technical aspects studied in the RESERVE project, mainly for providing innovative solutions for frequency and voltage control in a 100% RES European grid, have a positive impact on the present network codes in terms of improving them, while also allowing for the creation of new network codes altogether.

A.1.1 Frequency Control

The network codes and guidelines that currently cover frequency control are:

m) NC RfG;

n) NC DCC;

o) NC HVDC;

p) Balancing Guideline;

q) Network code on emergency and restoration;

r) System Operation Guideline

The NC RfG applies to new power-generating modules, defined as either synchronous power-generating modules or power park modules. Thus, the present network code for generators already applies to RES generation. Clear requirements for all type of generators (A, B, C, D - differentiated on installed capacity) are laid out in terms of minimum time periods for operating on different frequencies without disconnecting from the network and capability response to the limited frequency sensitive modes (over- and under-frequency) [17].

The NC DCC applies to all new transmission-connected demand and distribution facilities, closed distribution systems and new demand units used by a demand facility or a closed distribution system to provide demand response services to relevant power system operators and relevant TSOs. The code offers clear frequency ranges and time periods at which transmission-connected demand and distribution facilities and distribution systems are to remain connected to the network [18].

The balancing guideline (not yet approved at the date of this deliverable) defines the term of "balancing" as the entirety of actions and processes through which TSOs ensure, in a continuous way, the maintenance of power system frequency within a predefined stability range and the compliance with the amount of reserves needed with respect to required quality [19]. The guideline states the obligation of a TSO to develop terms and conditions for balancing service providers no later than six months after entry into force of the regulation. These terms and conditions are meant to provide support for demand facility owners, third parties and owners of power generating facilities from conventional and renewable energy sources as well as owners of energy storage units to become balancing service providers.

A.1.1.1 Storage

In both NC RfG and NC DCC, it is clearly specified that the regulation does not apply to storage devices, aside from pump-storage power-generating modules. Also, the balancing guideline requires each TSO to lay down the terms for storage facilities to become balancing service providers. In the network code on emergency and restoration (not yet approved), it is required for each TSO to establish in its power system defense plan the frequency thresholds at which the automatic switching or disconnection of energy storage units shall occur.

Therefore, there is no adopted regulation that covers clear frequency control requirements for ESSs. As for regulation that is pending approval, the balancing guideline and the network code on emergency and restoration impose that frequency control requirements for storage facilities are not to be established at ENTSO-E level, but by each TSO for its own power system.

An EU level code for ESSs could be established based on the experience of all TSOs.

Network codes to be drafted:

- Network code on the connection of ESSs.

A.1.1.2 Rate of change of frequency

Rate of change of frequency (RoCoF) is the time derivative of the power system frequency (df/dt). This quantity was traditionally of minor relevance for power systems with generation mainly based on synchronous generators, because of the inertia of these generators. It however becomes relevant now during significant load-generation imbalances (caused by disconnection of either large loads or generators, or by power system splits), when larger RoCoF values may be observed because of low power system inertia caused by disposal of synchronous generation in favor of inverter-based generation. In the absence of any control, inverter-based generation does not possess such inherent characteristics and high inverter penetration could therefore lead to higher RoCoF in a power system. Large RoCoF values may endanger secure power system operation because of mechanical limitations of individual synchronous machines (inherent capability), protection devices triggered by a particular RoCoF threshold value or timing issues related to load shedding schemes [20].

NC RfG and DCC demand that each TSO defines/requires the RoCoF, which a power generating module or a demand unit shall at least be capable of withstanding.

For example, in the case of Romania, the technical requirements for grid connection of synchronous generators were developed with NC RfG as guideline and adopted in August 2017. They require all synchronous generators to stay connected and operable at a RoCoF of 1Hz/s.

The technical requirements for demand connection are, at the date of this deliverable, in public consultation. They require all demand to stay connected at a RoCoF of 2Hz/s, for a time frame of 500 ms.

According to NC HVDC, an HVDC system shall be capable of staying connected to the network and operable if the network frequency changes at a rate between – 2,5 and + 2,5 Hz/s (measured at any point in time as an average of the rate of change of frequency for the previous 1 sec), while a DC-connected power park module shall be capable of staying connected to the remote-end HVDC converter station network and operable if the power system frequency changes at a rate up to +/– 2 Hz/s (measured at any point in time as an average of the rate of change of frequency for the previous 1 second) at the HVDC interface point of the DC-connected power park module at the remote end HVDC converter station for the 50 Hz nominal system [21].

For a future grid that has no mechanical inertia (such is the one defined in scenario SF_B), the RoCoF at which a generator, demand or HVDC system is to remain connected to the grid may increase. Meters and RoCoF units must have a high enough accuracy and granularity to capture the fast changes in frequency after certain disturbances. Furthermore, control schemes for maintaining frequency variations within stringent margins will be defined, preferably at ENTSO-E level.

Network codes to be modified:

s) NC RfG;

t) NC DCC;

u) NC HVDC.

A.1.1.3 Frequency containment and restoration

At the date of this deliverable, frequency control in Continental Europe is based on Policy 1 of the Continental Europe Operation Handbook, “Load-Frequency Control and Performance”. However, all policies contained within the Handbook have been re-evaluated and merged into the System Operation Guideline. This guideline, which is not yet approved[1], redefines the notions of primary, secondary and tertiary control. Upon approval of the guideline, these will be referred as frequency containment reserves (FCR), frequency restoration reserves (FRR) and replacement reserves (RR) [22].

Chapter 3.2 proposes a re-evaluation of the values of frequency quality target parameters, as well as FCR and FRR technical minimum requirements. The updated values of these parameters will be established as a result of SF_A and SF_B simulations.

Network codes to be modified:

v) System Operation Guideline.

A.1.2 Voltage control and management

The network codes and guidelines that currently cover voltage control are:

w) NC RfG;

x) NC DCC;

[1] The System operation guideline was approved on August 2nd and was published in the Official Journal of the European Union on August 25th (http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32017R1485&from=EN).

y) NC HVDC;

z) Network code on emergency and restoration;

aa) System Operation Guideline.

In NC RfG, clear requirements for all type D generators are laid out in terms of voltage stability, by establishing the minimum time periods for operating on different voltage ranges without disconnecting from the network and fault-ride-through capability response. For both synchronous power-generating modules and park modules, each TSO may specify the capability of a type B generating module to provide reactive power. For type C and D generators, a U-Q/P_{max} profile is defined regarding reactive power capability at maximum capacity [17].

NC DCC contains clear voltage ranges and time periods at which transmission-connected demand, distribution facilities, and distribution systems are to remain connected to the network. In terms of voltage/reactive power control of demand, in the Romanian requirements for demand connection it is imposed that measurements are integrated in the DMS-SCADA/ EMS-SCADA systems [18].

NC HVDC contains the voltage ranges and time periods at which an HVDC system, a DC-connected power park module and a remote-end HVDC converter station are to stay connected to the grid, while also establishing the requirements for the U-Q/P_{max} profile (maximum range of Q/P_{max} and maximum range of steady-state voltage level). Furthermore, parameters for a fault-ride-through capability profile of an HVDC converter station are provided [21].

The network code on emergency and restoration mentions voltage control related to the implementation in the power system defense plan of each TSO of a scheme against voltage collapse, which may include one or more of the following: a scheme for low voltage demand disconnection according to NC DCC, a blocking scheme for on load tap changers according to NC DCC and power system protection schemes for voltage management. Also, a procedure containing a set of measures to manage voltage deviations outside the operational security limits set in the System Operation Guideline will be included in the power system defense plan [23].

As stated in 4.2.1, scenario SV_A presents new requirements for voltage control. It proposes the introduction of new technologies at power converter level (a WSI/WBSI Tool and a VOI controller) that send measurements to a SSAU, where a stability assessment is carried through. If an unstable situation is detected, the DSO will take corrective measures through the DMS.

According to 4.2.2, RES (defined as generation, EVs and ESSs) should be able to provide reactive power in the future to provide voltage control (to operate at a leading power factor). In the NC DCC this aspect is already covered, by the mere definition of “demand response reactive power control”; which means reactive power or reactive power compensation devices in a demand facility or closed distribution system that are available for modulation by the relevant power system operator or relevant TSO. The compensation devices may easily be SVCs, STATCOMs and UPFCs - all these devices may both inject or absorb reactive power.

Network codes to be drafted:

bb) Distribution Operation Guideline.

cc) Network code on the connection of ESSs.

A.2 Appendix B: Summary of the research objectives in the different scenarios

A.2.1 SF_A: Mixed Mechanical-Synthetic Inertia

SF_A focuses on frequency control on a 100% RES power system with hydro generation, where the inertia has significantly decreased, leading to the occurrence of new power system dynamics. Frequency is a global parameter of an AC power system as a whole. Thereby, frequency control is provided by the contribution of all qualified network users based on a standard procedure, eventually, if possible, uniformly located from an electrical point of view. In a large interconnected power system, the frequency is easier to control around the reference value because frequency variation is a consequence of active power unbalances.

A.2.1.1 Vision

Study of frequency in a 100% RES power system with hydro generation, where power system inertia will decrease a lot and new dynamic issues will arise

A.2.1.2 Research Question

How to decrease the rate-of-change-of-frequency (RoCoF), and implement primary (frequency containment reserve) and secondary frequency (frequency restoration reserve) controls considering a decrease in mechanical inertia in the power system and the intermittency of generation and operating reserves?

A.2.1.3 Technical Assumptions

dd) For the RoCoF:

- For the time scale considered for RoCoF control (<5s) following a contingency, the frequency cannot be assumed to be the same everywhere.
- The PMU measurements are characterized by noise and latency that affect both quality and reliability of the signal.
- RoCoF/Virtual Inertia controllers do not respond instantaneously to RoCoF variations, as opposed to SMs.
- Risk of malfunction or failure of these controllers must be considered.

ee) For primary control

- Independent reaction to either the variations of the rotor speed (synchronous generators) or of the frequency at PCC (point of common coupling – connection point) above acceptable limits (this is classical approach)
- Faster reaction from generation units; since the time span is 1(or less)-5 seconds, large power capability is more important than energy reserve (new approach): batteries, flywheels,
- Mixed signal inputs can be considered (Δf and df/dt); this means adapted digital control hardware
- PMU devices installed in transmission networks
- Frequency data shall be sent to several primary control generation units

ff) For secondary control

- Inter-TSO control scheme; requires interconnected ICT infrastructure (currently national scheme is implemented, except Portugal-Spain)
- PMU / smart meters installed on interconnection lines and on the control plants

A.2.1.4 Scope

gg) For the RoCoF:

- Find trade-off between local frequency measurement and global frequency estimation.
- Coordinate RoCoF control devices at different levels, namely Low-Voltage, Distribution and Transmission sides.
- Minimize response time of RoCoF and Virtual Inertia controllers to resemble that of synchronous machines.

hh) For primary control

- Minimize the time reaction for frequency stabilization (classical approach)
- Stabilize the frequency to quasi steady-state value with faster generation units / maintain power system stability from frequency point of view by avoiding the frequency to drop to critical values
- Optimized response, for better oscillations damping
- Collecting data with high granularity
- The frequency (rapid variations) can be different in transmission and distribution grids. The same signal shall be sent to all units.

ii) For secondary control

- Some countries may not be capable of providing power balancing because they don't have hydro; in the future, maybe storage will be widely available.
- Synchronized data is required for error limitation

A.2.1.5 Guiding Standards

jj) Commission Regulation (EU) 2016/631 of 14 April 2016 establishing a network code on requirements for grid connection of generators.

kk) ENSTO-E, Network Code on Load-Frequency Control and Reserves, 2013

ll) IEEE Standard for Synchrophasor Measurements for Power Systems. IEEE Std C37.118.1-2011 (Revision of IEEE Std C37118-2005). 2011

mm) IEEE Standard for Synchrophasor Data Transfer for Power Systems. IEEE Std. C37.118.2-2011 (Revision of IEEE Std C37118-2005). 2011

A.2.2 SF_B: Full Synthetic Inertia

The differences between SF_A and SF_B are:

1. The time window of inertial, primary and secondary control in SF_B is smaller than SF_A. This is not determined yet, and we will provide you with an initial time frame after conducting comprehensive analysis and test scenarios/simulations.

2. In SF_B, frequency control of RES-connected converters will be different, as this control will be developed based on LSD concept. This is probably different than SF_A, in which LSD might/might not be applicable (due to the high mechanical oscillations "nonlinearity" posed by the existing hydro-generation "as a typical synchronous generator". The applicability of LSD in SF_A depends on different aspects, e.g. percentage of existing hydro-generation in the power system. However, this will be investigated by RWTH Aachen.

A.2.2.1 Vision

Study of frequency stability and control in a linear swing dynamical power system, with 100% non-hydro RES. That is, with almost fully synthetic inertia, frequency in a futuristic power system with HVDC, hybrid AC/DC and very low inertia (only hydro) or perhaps with no inertia.

A.2.2.2 Research Questions

nn) How to achieve a linear swing dynamical power system, that will offer a level of flexibility in frequency profile (constraints and thresholds). Also, with linear swing dynamical power system, which gives the precise knowledge of power system small and large signal stability, provide a consistent control performance.

oo) Without LSD, we may not be able to analyze the power system stability and get the knowledge of whole state space. Also, the nonlinear swing dynamics resulted in the electromechanical oscillations will affect the control performance.

pp) How to decrease rate-of-change-of-frequency (RoCoF), and implement primary and secondary frequency controls with the corresponding power reserve, considering full (almost full) synthetic inertia

A.2.2.3 Technical Assumptions

The assumptions are still being finalized in WP2

A.2.2.4 Scope

The scope for this scenario is still being finalized in WP2

A.2.2.5 Guiding Standards

The guiding standards relevant to SF_B are still being studied in WP2

A.2.3 SV_A: Dynamic Voltage Stability

In the SV_A scenario, the focus is on the Online Stability Margin Monitoring and Control (OSMMC), which maintains the dynamic voltage stability in the power system. It prevents harmful oscillations in the power system voltage RMS when changes in the power system load and generation occur, even when there is a high penetration of active inverters in the power system. The details for this scenario are as follows:

A.2.3.1 Vision

Study of voltage transients, under load and local changes; It deals with voltage harmonics and stability

A.2.3.2 Research Question

How to maintain dynamic voltage stability in a distribution system where the number of controllable power converters increases?

A.2.3.3 Technical Assumptions

qq) All inverters are designed to be stable, that is adhering to standards and does not tend to be very aggressive.

rr) A radial structure of LV grid is assumed and specifically an AC grid is assumed to be the case. Although in future most loads are going to be DC.

ss) To measure the inverters input impedance, there is always some neighboring inverter and the inverters need to register with the DSO to have a sort of identification or map. The DSO can then know the order from Inverter 1 which is closest to the SSAU and Inverter N which is the farthest

A.2.3.4 Scope

tt) The stability method and control is applicable to LV grids immaterial of the size.

uu) The method is also possible and applicable for DC distribution grids, since originally the idea of Middlebrook stability came from DC systems. So, with minor modifications in algorithm, it is possible to do for DC distribution as well.

vv) Large scope for fast communication, large communication network between inverters to the SSAU.

A.2.3.5 Guiding Standard

ww) ESB Networks' Distribution Code - this document is available online. The codes in this document are very classical. According to the code, the inverters can only operate in lagging power factor close to 1. However, the inverters can be made to inject reactive power like a capacitor (leading power factor) for enhanced voltage support.

xx) Furthermore, with the stability monitoring concept defined in SV_A, one can already start specifying standards for minimum gain and phase margin (frequency domain specifications) that the power system should possess for stable operation.

A.2.4 SV_B: Active Voltage Management

Active Voltage Management maintains the steady-state RMS value of the voltage within acceptable limits through the control of reactive and/or active power from a RES inverter. The goal is to maintain the voltages on distribution network LV feeders within acceptable standards through a harmonized control strategy from RES. This strategy considers also the degree of voltage unbalance across the three phases and thermal flow limits along the feeder.

Synchronized measurements and control signals are vital for the success and validation of the method in a field trial environment. The time scale envisioned for the voltage regulation is of the order of minutes.

A.2.4.1 Vision:

Study of steady-state voltages in a distribution grid. The focus is on voltage management and not stability.

A.2.4.2 Research Question

How to maintain the steady-state voltage within acceptable limits in the face of variable generation and demand growth from RES? Can the inverter technology inherent to a RES be used in a strategic manner to better manage the reactive power needs of a power system towards 100% RES penetration?

A.2.4.3 Scenario Objective(s)

yy) Minimize voltage unbalance on three phase LV feeders to promote the sustained connection of RES.

A.2.4.4 Technical Assumptions

Deployment of three-phase unbalanced Optimal Power Flow solutions in decentralized manner with use of volt-VAr curves.
Assuming:

zz) reactive power control from RES technologies.

aaa) Active voltage management

bbb) volt-VAr implementation including a leading power factor.

ccc) Accurate representation of ZIP demand models

A.2.4.5 Scope

- Low Voltage distribution feeders with distributed energy resources.
- Management of voltages: resulting power flows affecting steady state operation with high RES uptake on distribution systems.
- How best to manage finite capacity of distribution networks?
- Modular

A.2.4.6 Guiding Standard

ddd) EN 50160

A.3 Present Version of SGAM Layers

This annex contains the Component and Function layers of the Smart Grid Architectural Model (SGAM) for the scenarios studied in RESERVE. Here, the requirements discussed and defined in Sections 3.2 and 4.2 are drawn in the SGAM Component and Function layers. Table 4 describes these two layers accordingly [24]:

Table 4. SGAM Layers

SGAM Layer	Definition
Component	Shows the physical distribution of the components in the smart grid context.
Function	Shows the functions and services and where are they executed (e.g. field, station).

The SGAM Component and Functional layers presented here are the latest version of these layers. The SGAM Communications and Information layers in the annexes of D1.3 are based on the previous versions of these layers. All the SGAM layers (Component, Function, Communication, and Information layers) will be continually updated and harmonized through the course of the project. These layers could be useful later in the project to help standardize the definitions of the component and functional requirements in the smart grid context.

A.3.1 Scenario SF_A

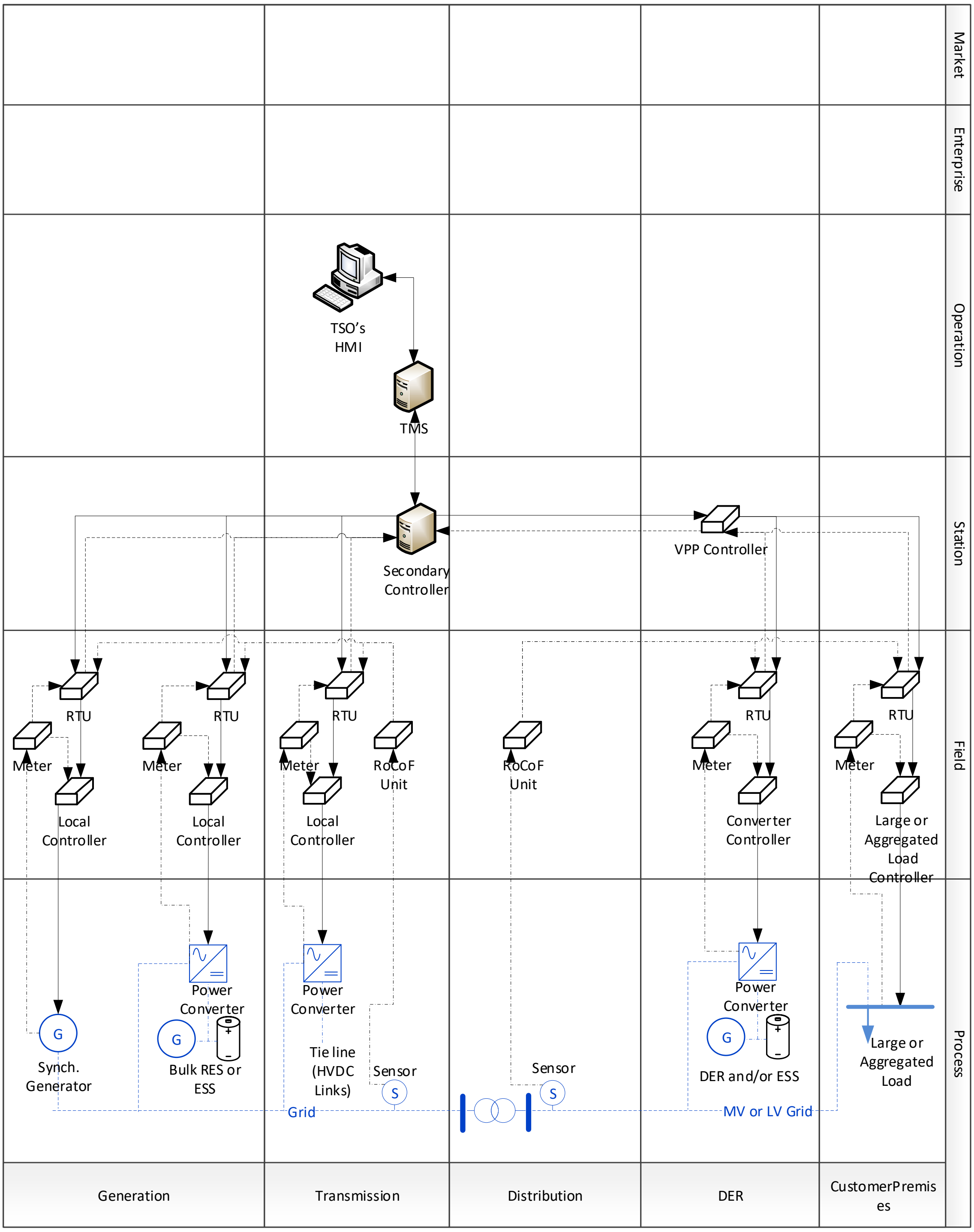

Figure 8. SGAM Component Layer for SF_A

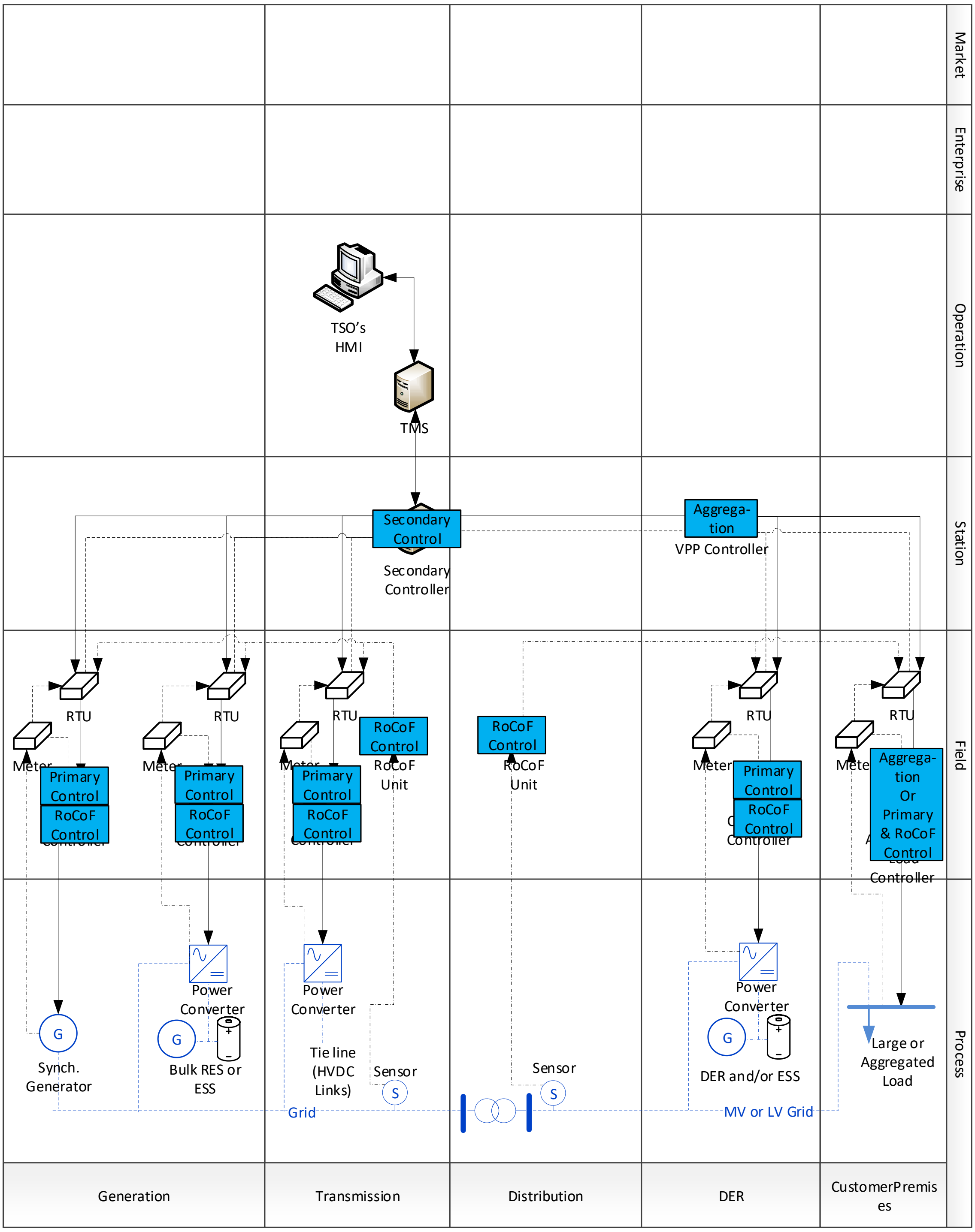

Figure 9. SGAM Function Layer for SF_A on top of the Component Layer

A.3.2 Scenario SF_B

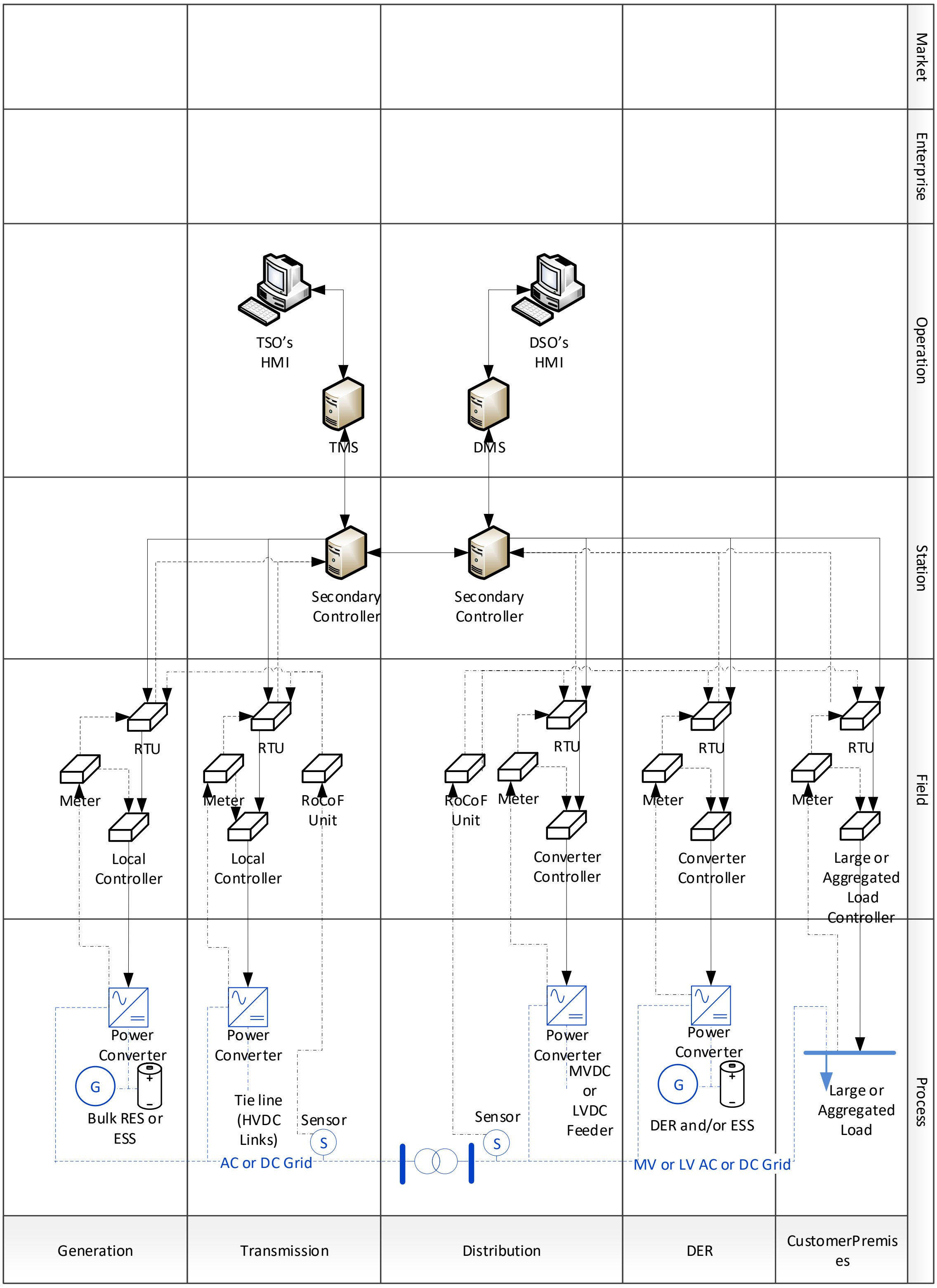

Figure 10. SGAM Component Layer of SF_B

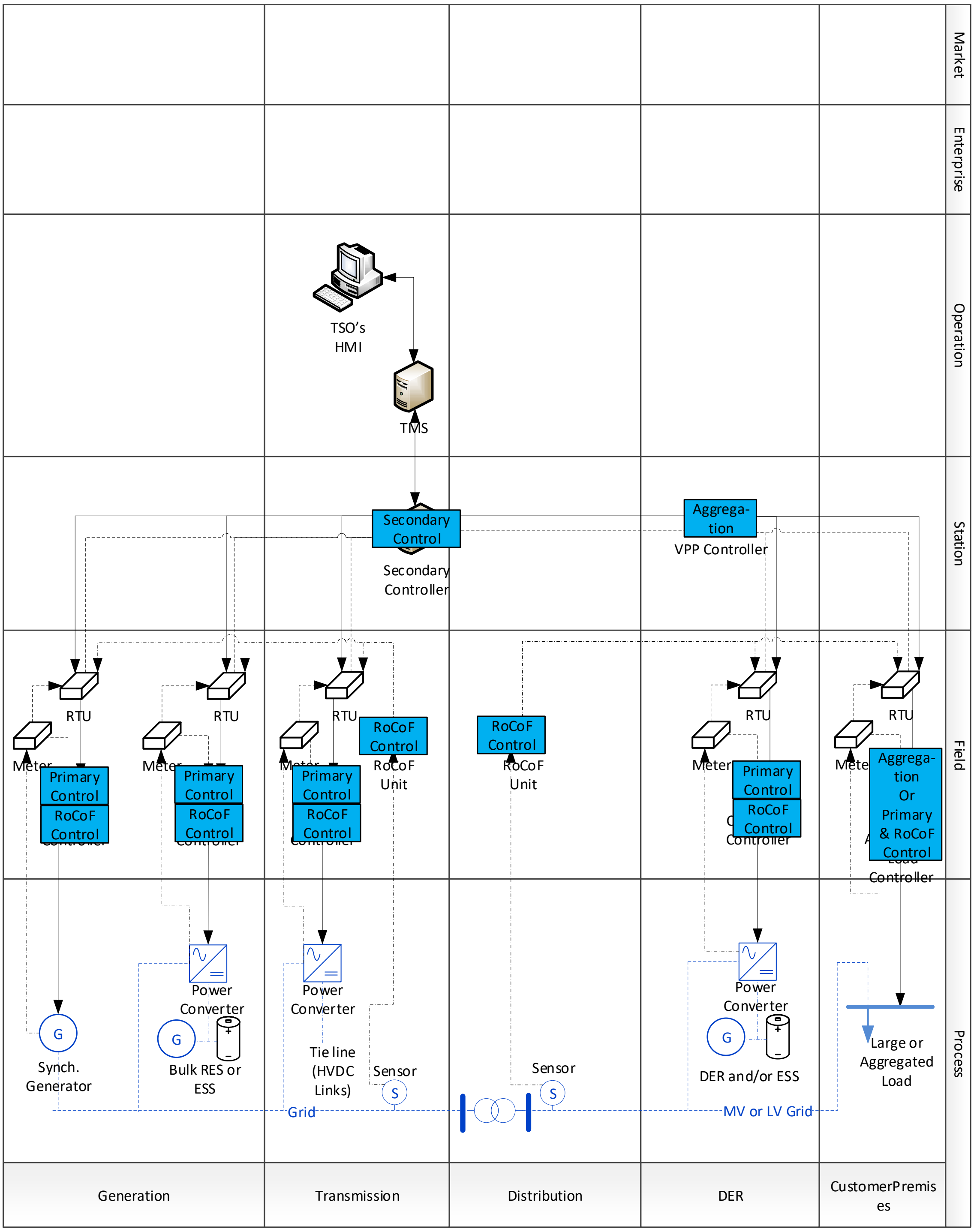

Figure 11. SGAM Function Layer for SF_B on top of the Component Layer

A.3.3 Scenario SV_A

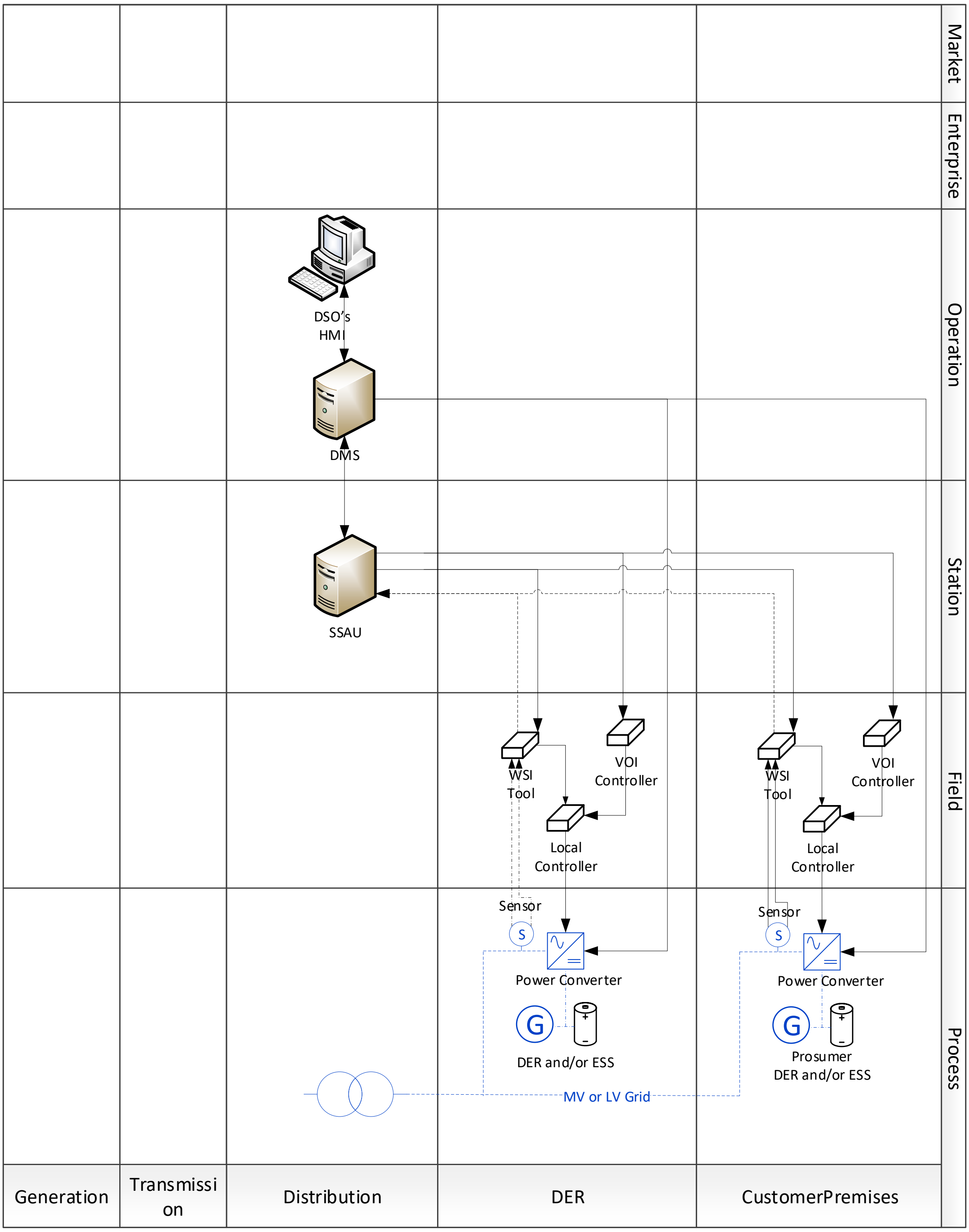

Figure 12. SGAM Component Layer for SV_A

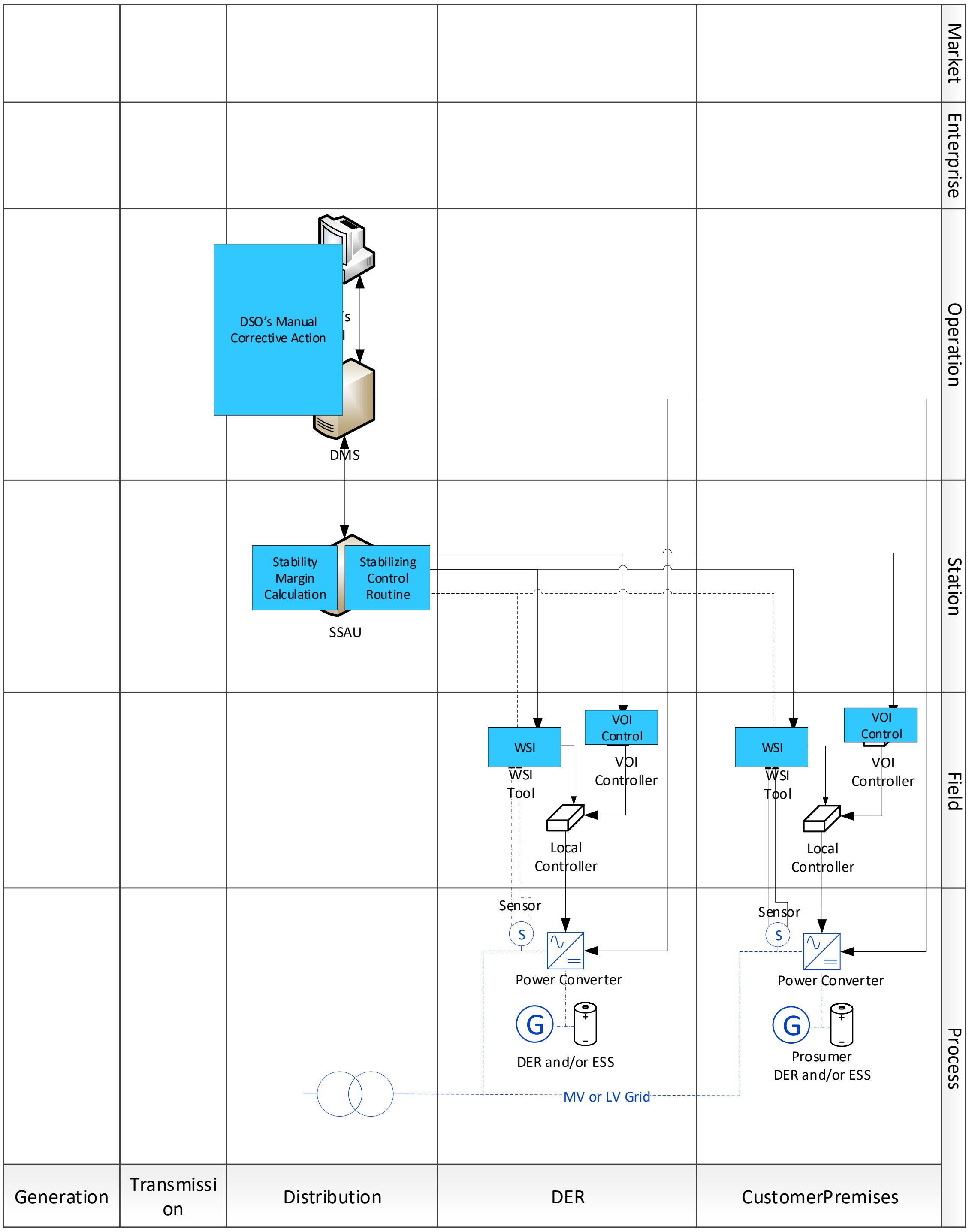

Figure 13. SGAM Function Layer for SV_A on top of the Component Layer

A.3.4 Scenario SV_B

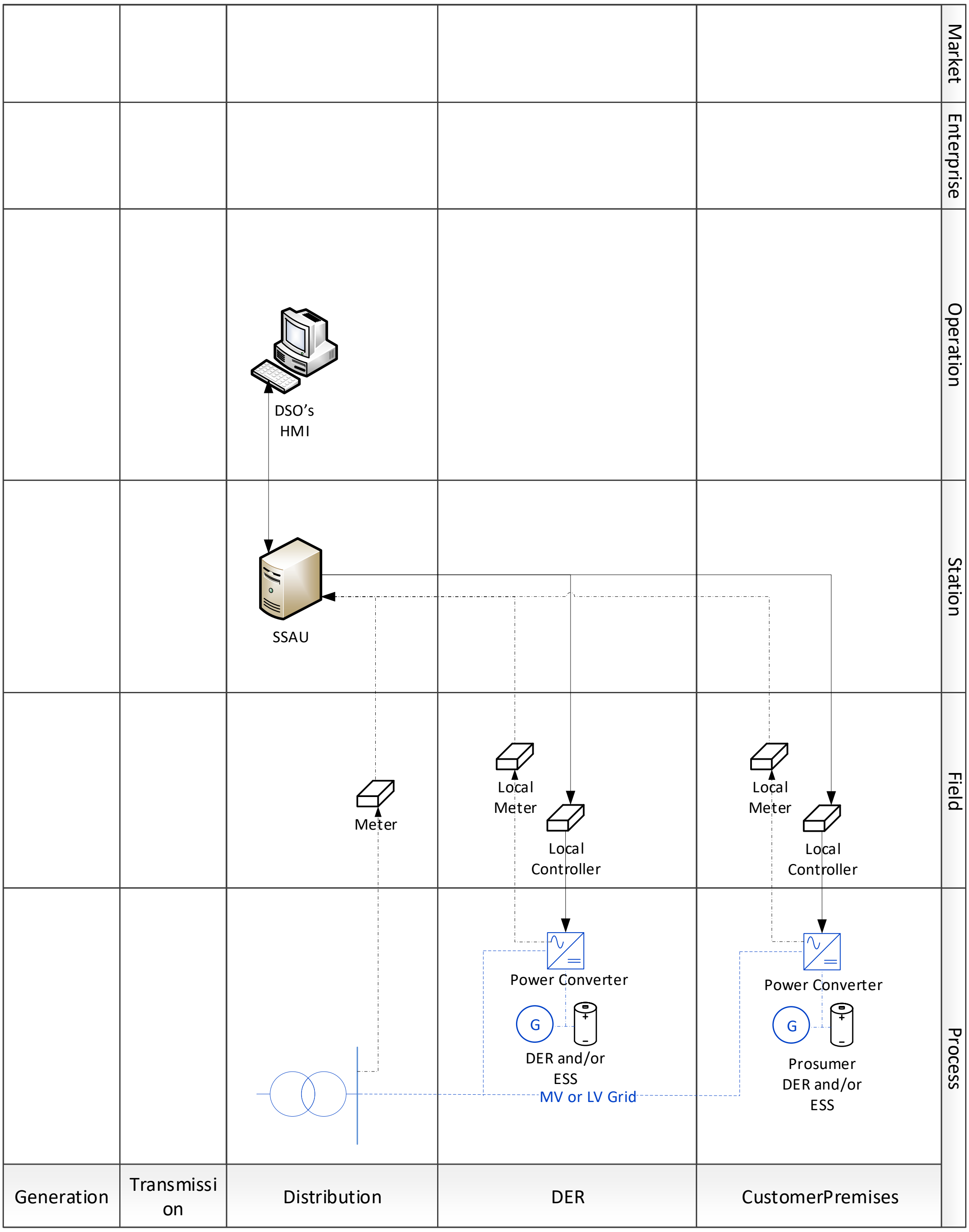

Figure 14. SGAM Component Layer for SV_B

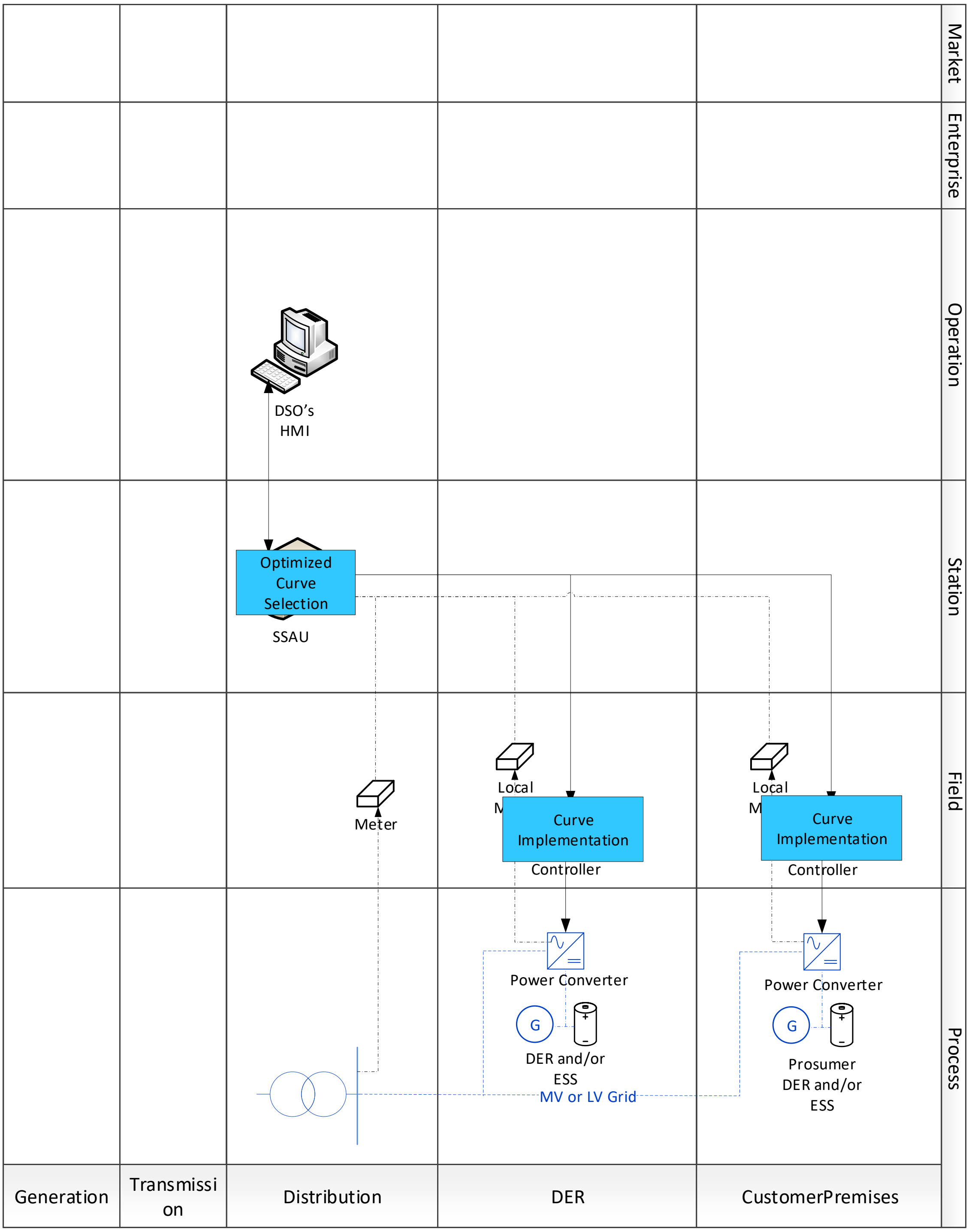

Figure 15. SGAM Function Layer for SV_B on top of the Component Layer