OSMOSE

OPTIMAL SYSTEM-MIX OF FLEXIBILITY SOLUTIONS FOR EUROPEAN ELECTRICITY

Final report summarizing main demo results

Ex-post market, regulatory and scalability-replicability analysis of the Italian Demo

D5.6

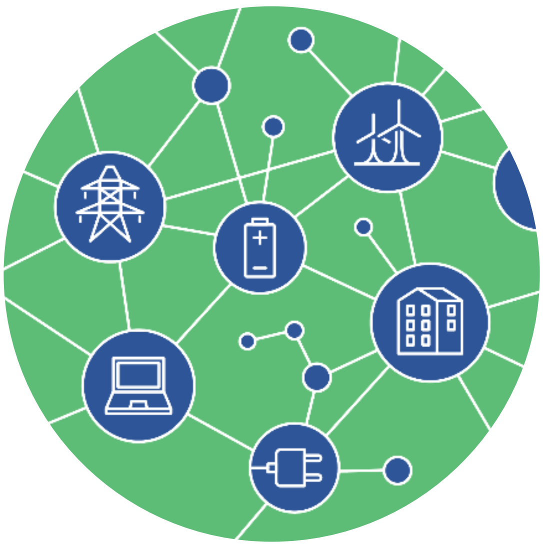

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Table of content

0 EXECUTIVE SUMMARY ... 13

1 ITALIAN DEMO ... 14

1.1 USE CASES ... 14
1.1.1 Use case 1 ... 14
1.1.2 Use case 2 ... 14
1.1.3 Use case 3 ... 15

2 ANALYSIS OF SERVICES INCLUDED IN THE ITALIAN DEMO ... 16

2.1 SYNTHETIC INERTIA (SI) ... 16
2.1.1 Description ... 16
2.1.2 Applied technology ... 16
2.1.3 Regulation and Market ... 17
2.2 AUTOMATIC FREQUENCY RESTORATION RESERVE ... 22
2.2.1 Description ... 22
2.2.2 Applied technology ... 23
2.2.3 Regulation and Market ... 25
2.3 CONGESTION MANAGEMENT ... 30
2.3.1 Description ... 30
2.3.2 Applied technology ... 30
2.3.3 Regulation and Market ... 32
2.4 AUTOMATIC VOLTAGE CONTROL ... 35
2.4.1 Description ... 35
2.4.2 Applied technology ... 36
2.4.3 Regulation and Market ... 36
2.5 **COMPLIANCE OF THE ANALYSED SERVICES WITH MARKET MODELS** ... 40

3 SCALABILITY AND REPLICABILITY ANALYSIS OF THE ITALIAN DEMO WITHIN OSMOSE WP5 ... 42

3.1 INTRODUCTION ... 42
3.2 OVERVIEW OF EXISTING METHODOLOGIES ... 42
3.3 THE PROPOSED APPROACH FOR THE SRA WITHIN OSMOSE WP5 ... 44

4 SUBJECTS OF THE SRA APPLIED TO OSMOSE WP5 DEMOS ... 47

4.1 FUNCTIONS AND TOPICS UNDER INVESTIGATION ... 47
4.1.1 UC1 applications/functionalities ... 47
4.1.2 UC2 applications/functionalities ... 49
4.1.3 UC3 applications/functionalities ... 49
4.1.4 Cybersecurity ... 49
4.2 INTERACTIONS BETWEEN TOOLS/FUNCTIONALITIES ... 50
4.3 SRA PERIMETER ... 50

5 SCALABILITY AND REPLICABILITY KEY FACTORS/DIMENSIONS ... 51

5.1 DIMENSION CLASSIFICATIONS ... 51
5.1.1 Classification according to the relevant areas ... 51
5.1.2 Classification according to the Smart Grid Architecture Model layers ... 54
5.1.3 Classification between technical vs non-technical features ... 55
5.2 SRA DIMENSION IDENTIFICATION ... 55

6 SRA METHODOLOGY DEFINITION AND IDENTIFICATION OF BENEFITS ... 58

6.1 METHODOLOGY FOR SRA DIMENSION ASSESSMENT ... 58
6.1.1 Scores & weights: a description-based method ... 59

6.2 FURTHER ANALYSES ... 61
6.2.1 Quantitative SRA applied to UC2 functionalities ... 61
6.2.2 Cybersecurity assessment methodology ... 62
6.2.3 Benefits' identification ... 63

7 DATA AND INFORMATION COLLECTION ... 66

7.1 SRA QUESTIONNAIRE ... 66
7.1.1 Questions on scalability technical factors (QS1-QS20) ... 67
7.1.2 Questions on scalability economic factors (QS21-QS28) ... 67
7.1.3 Questions on scalability acceptance factors (QS29-QS36) ... 68
7.1.4 Questions on replicability technical factors (QR1-Q12) ... 68
7.1.5 Questions on replicability economic factors (QR13-Q20) ... 68
7.1.6 Questions on replicability regulatory factors (QR21-Q28) ... 69
7.2 SR MC-CBA QUESTIONS & ANSWERS ... 69

8 QUALITATIVE AND QUANTITATIVE EVALUATION OF THE DIMENSIONS ... 71

8.1 PRELIMINARILY ANALYSIS OF QUESTIONNAIRES ... 71
8.1.1 Completeness of the answered questionnaire ... 71
8.1.1.1 **Added questions on scalability** ... 71
8.1.1.2 **Added questions on replicability** ... 74
8.1.1.3 General statistics on completeness of the answers ... 75
8.2 SRA ASSESSMENT RESULTS ... 76
8.2.1 UC 1 scalability results ... 76
8.2.1.1 DTR scalability ... 76
8.2.1.2 **Forecasting software** - PREVEL scalability ... 78
8.2.1.3 Z-EMS scalability ... 80
8.2.1.4 Dashboard scalability ... 82
8.2.1.5 Hand Of Data scalability ... 83
8.2.1.6 DSR for congestion resolution scalability ... 84
8.2.2 UC 1 replicability results ... 86
8.2.2.1 DTR replicability ... 86
8.2.2.2 **Forecasting software** - PREVEL replicability ... 88
8.2.2.3 Z-EMS replicability ... 89
8.2.2.4 Dashboard replicability ... 90
8.2.2.5 Hand Of Data replicability ... 91
8.2.2.6 DSR for congestion resolution replicability ... 92
8.2.3 UC 2 scalability results ... 94
8.2.3.1 RES + BESS and DFIG for SI provision scalability ... 94
8.2.3.2 RES + BESS and DFIG for AVC provision scalability ... 98
8.2.4 UC 2 replicability results ... 101
8.2.4.1 RES + BESS and DFIG for SI provision replicability ... 101
8.2.4.2 RES + BESS and DFIG for AVC provision replicability ... 104
8.2.5 UC 3 scalability results ... 107
8.2.5.1 DSR for AVC provision scalability ... 107
8.2.6 UC 3 replicability results ... 109
8.2.6.1 DSR for AVC provision replicability ... 109
8.3 RESULTS OF QUANTITATIVE SRA ... 110
8.3.1 Quantitative SRA applied to UC2 functionalities ... 110
8.3.1.1 SI ... 111
8.3.1.2 AVC ... 114
8.3.2 WP5 demo cybersecurity scalability ... 116
8.3.2.1 NIST 800-53 compliance ... 117
8.3.2.2 Architecture analysis ... 117
8.4 IDENTIFIED BENEFITS FOR THE INNOVATIVE OPERATION ... 122
8.4.1 Impact of Scalability and Replicability on Costs and Benefits ... 123

9 RESULTS, RECOMMENDATIONS, RULES, AND BARRIERS ... 127

9.1 UC1 DISCUSSION ... 127
9.2 UC2 DISCUSSION ... 133

9.3 UC3 DISCUSSION 135
10 REFERENCES 137
11 ATTACHMENT 143
12 APPENDIX 144
12.1 USED TECHNOLOGIES 144

List of figures

Figure 2.1 PICASSO implementation project (as of April 2021) (Source [35]) 25
Figure 2.2 Example of comparison between static and dynamic line ratings (source: IRENA [56]) 31
Figure 2.3 Q=f(ΔV) function (Source: [23]) 39
Figure 3.1 Vision for scalability and replicability of the GRID4EU 42
Figure 3.2 SRA guidelines [88] 46
Figure 5.1 SGAM framework 54
Figure 6.1 The grid+ methodology [90] 58
Figure 6.2 Flow chart to evaluate the provincial annual availability for providing SI and AVC if services are supplied by WTs 62
Figure 6.3 Illustration of the project assessment framework categories [103] 65
Figure 8.1 Radar plot of DTR scalability results 78
Figure 8.2 Radar plot of PREVEL scalability results 80
Figure 8.3 Radar plot of Z-EMS scalability results 81
Figure 8.4 Radar plot of the dashboard scalability results 82
Figure 8.5 Radar plot of the Hand Of Data scalability results 84
Figure 8.6 Radar plot of the DSR for CR scalability results 85
Figure 8.7 Radar plot of DTR replicability results 87
Figure 8.8 Radar plot of PREVEL replicability results 88
Figure 8.9 Radar plot of Z-EMS replicability results 90
Figure 8.10 Radar plot of the dashboard replicability results 91
Figure 8.11 Radar plot of the Hand Of Data replicability results 92
Figure 8.12 Radar plot of the DSR for CR replicability results 93
Figure 8.13 Radar plot of RES + BESS and DFIG for SI provision scalability results 97
Figure 8.14 Radar plot of RES +BESS and DFIG for AVC provision scalability results 101
Figure 8.15 Radar plot of RES + BESS and DFIG for SI provision replicability results 104
Figure 8.16 Radar plot of RES + BESS and DFIG for AVC provision replicability results 107
Figure 8.17 Radar plot of the DSR for AVC scalability results 108
Figure 8.18 Radar plot of DSR for AVC replicability results 110
Figure 8.19 Overall rated power and unit production of installed wind farms (2015 to 2019) 111
Figure 8.20 Number of hours in which wind farms are able to provide SI according to the considered threshold on generation coefficient (30%) – years 2015 to 2019 and average 111
Figure 8.21 Unit production (asterisks), installed power in 2019 (dotted line) and number of hours in which wind farms are able to provide SI according to the considered threshold on generation coefficient (30%) 112
Figure 8.22 Duration curve of the hourly unit production for some provinces: TA/CE (a) and FG (b) 113
Figure 8.23 Duration curve of: overall unit production, overall unit production considering only plants exceeding the SI threshold (generating coefficient 30%), overall rated power considering only plants exceeding the SI threshold, in bold (generating coefficient 30%) 114
Figure 8.24 Number of hours in which wind farms are able to provide AVC according to the considered threshold on generation coefficient (10%) – years 2015 to 2019 and average 115
Figure 8.25 Unit production (asterisks), installed power in 2019 (dotted line) and number of hours in which wind farms are able to provide AVC according to the considered threshold on generation coefficient (10%) 115
Figure 8.26 For each bidding zone hosting wind farms, duration curve of the overall rated power considering only plants exceeding the AVC threshold (generating coefficient 10%) 116
Figure 8.27 NoR (Req_Cat, SAL) 117
Figure 8.28 - Demo 5 network diagram in CSET 118
Figure 8.29 – PoC (Asset_Cat,1_Plant, 1_BSP) ; NoC (Asset_Cat,1_Plant, 1_BSP) 119
Figure 8.30 - NoC for 3 Demo5 setups 120
Figure 8.31 – NoC(Asset_Cat, n_Plant) 120
Figure 8.32 - NoC (n_Plant | m_BSP) 121
Figure 8.33 - NoC (n_Plant | m_BSP) (granularity 5 plants) 121
Figure 8.34 - NoC (m_BSP | n_Plant) 121
Figure 8.35 Example of mapping applied to the sensor based DTR function 124

List of tables

Table 2.1 Property of technologies to provide FFR (Source: [13]) 17
Table 2.2 Characteristics of PGM types for synchronous areas according to EU 2016/631. 19
Table 2.3 Characteristics of PGM types according to the Italian network code [21]. 20
Table 2.4 Comparison of frequency grid services in the European countries (Source: D1.1 SmarNet [30]) 22
Table 2.5 Capability of some DERs to provide current AS (Source D1.2 SmartNet [32]) 23
Table 2.6 Overview of DERs participation in Ancillary Services Markets (Source [33]) 24
Table 2.7 Definition of the standard aFRR balancing energy product 26
Table 2.8 FRR requirements for MSD 28
Table 2.9 Voltage control services in some EU countries (Source [30]). 36
Table 2.10 PPM requirements for Voltage control (Source: [74]) 37
Table 5.1 Scalability areas and factors 52
Table 5.2 Replicability areas and factors 53
Table 5.3 Smart Grid Architecture Model applied to SRA 55
Table 5.4 Correspondence table for SGAM and Area classification 56
Table 6.1 Scalability scores 60
Table 6.2 Replicability scores 60
Table 6.3 Scalability qualitative and quantitative weights 61
Table 6.4 Replicability qualitative and quantitative weights 61
Table 6.5 Wind and PV installed power (October 2020 and PNIEC targets) 61
Table 7.1 MC-CBA questions 69
Table 8.1 Initial number of questions 71
Table 8.2 General statistics of the unanswered questions – UC1 75
Table 8.3 General statistics of the unanswered questions – UC2 75
Table 8.4 General statistics of the unanswered questions – UC3 76
Table 8.5 Scalability of weather-based DTR 76
Table 8.6 Scalability of sensor-based DTR 77
Table 8.7 DTR scalability weighted scores 78
Table 8.8 DTR scalability indicators 78
Table 8.9 Scalability of PREVEL tool 78
Table 8.10 PREVEL scalability weighted scores 80
Table 8.11 PREVEL scalability indicators 80
Table 8.12 Scalability of Z-EMS 80
Table 8.13 Z-EMS scalability weighted scores 81
Table 8.14 Z-EMS scalability indicators 81
Table 8.15 Scalability of the dashboard 82
Table 8.16 Dashboard scalability weighted scores 83
Table 8.17 Dashboard scalability indicators 83
Table 8.18 Scalability of the Hand Of Data 83
Table 8.19 Hand Of Data scalability weighted scores 84
Table 8.20 Hand Of Data scalability indicators 84
Table 8.21 Scalability of the DSR for congestion resolution 84
Table 8.22 DSR for CR scalability weighted scores 85
Table 8.23 DSR for CR scalability indicators 85
Table 8.24 Replicability of weather-based DTR 86
Table 8.25 Replicability of sensor-based DTR 86
Table 8.26 DTR replicability weighted scores 87
Table 8.27 DTR replicability indicators 88
Table 8.28 Replicability of PREVEL tool 88
Table 8.29 PREVEL replicability weighted scores 89
Table 8.30 PREVEL replicability indicators 89
Table 8.31 Replicability of Z-EMS 89
Table 8.32 Z-EMS replicability weighted scores 90

TABLE 8.33 Z-EMS REPLICABILITY INDICATORS 90
TABLE 8.34 REPLICABILITY OF THE DASHBOARD 90
TABLE 8.35 DASHBOARD REPLICABILITY WEIGHTED SCORES 91
TABLE 8.36 DASHBOARD REPLICABILITY INDICATORS 91
TABLE 8.37 REPLICABILITY OF THE HAND OF DATA 91
TABLE 8.38 HAND OF DATA REPLICABILITY WEIGHTED SCORES 92
TABLE 8.39 HAND OF DATA REPLICABILITY INDICATORS 92
TABLE 8.40 REPLICABILITY OF THE DSR FOR CONGESTION RESOLUTION 92
TABLE 8.41 DSR FOR CR REPLICABILITY WEIGHTED SCORES 93
TABLE 8.42 DSR FOR CR REPLICABILITY INDICATORS 93
TABLE 8.43 SCALABILITY OF RES + BESS FOR SI PROVISION 94
TABLE 8.44 SCALABILITY OF DFIG FOR SI PROVISION 95
TABLE 8.45 RES + BESS AND DFIG FOR SI PROVISION SCALABILITY WEIGHTED SCORES 97
TABLE 8.46 RES + BESS AND DFIG SI FOR PROVISION SCALABILITY INDICATORS 97
TABLE 8.47 SCALABILITY OF RES + BESS FOR AVC PROVISION 98
TABLE 8.48 SCALABILITY OF DFIG FOR AVC PROVISION 99
TABLE 8.49 RES +BESS AND DFIG FOR AVC PROVISION SCALABILITY WEIGHTED SCORES 101
TABLE 8.50 AVC PROVISION SCALABILITY INDICATORS 101
TABLE 8.51 REPLICABILITY OF RES + BESS FOR SI PROVISION 101
TABLE 8.52 REPLICABILITY OF DFIG FOR SI PROVISION 103
TABLE 8.53 RES + BESS AND DFIG FOR SI PROVISION REPLICABILITY WEIGHTED SCORES 104
TABLE 8.54 RES + BESS AND DFIG FOR SI PROVISION REPLICABILITY INDICATORS 104
TABLE 8.55 REPLICABILITY OF RES + BESS FOR AVC PROVISION 104
TABLE 8.56 REPLICABILITY OF DFIG FOR AVC PROVISION 105
TABLE 8.57 RES + BESS AND DFIG FOR AVC PROVISION REPLICABILITY WEIGHTED SCORES 107
TABLE 8.58 AVC PROVISION REPLICABILITY INDICATORS 107
TABLE 8.59 SCALABILITY OF THE DSR FOR AVC 107
TABLE 8.60 DSR FOR AVC SCALABILITY WEIGHTED SCORES 108
TABLE 8.61 DSR FOR AVC SCALABILITY INDICATORS 109
TABLE 8.62 REPLICABILITY OF THE DSR FOR AVC 109
TABLE 8.63 DSR FOR AVC REPLICABILITY WEIGHTED SCORES 110
TABLE 8.64 DSR FOR AVC REPLICABILITY INDICATORS 110
TABLE 8.65 ASSET INVENTORY 119
TABLE 8.66 FUNCTIONALITIES-BENEFITS MATRIX 123
TABLE 9.1 UC1- RESULTING SCALABILITY INDICATORS 127
TABLE 9.2 UC1-RESULTING REPLICABILITY INDICATORS 127
TABLE 9.3 UC2-RESULTING SCALABILITY INDICATORS 133
TABLE 9.4 UC2-RESULTING REPLICABILITY INDICATORS 133
TABLE 9.5 UC3- RESULTING INDICATORS 135
TABLE 12.1 HW&SW – PREVEL (UC 1) 145
TABLE 12.2 HW&SW – SENSOR-BASED DTR (UC 1) 146
TABLE 12.3 HW&SW – WEATHER-BASED DTR (UC 1) 147
TABLE 12.4 HW&SW - Z-EMS (UC 1) 148
TABLE 12.5 HW&SW - DSR (UC 1) 149
TABLE 12.6 HW&SW – RES FOR SI AND AVC IN THE CASE OF BESS (UC 2) 150
TABLE 12.7 HW&SW - RES FOR SI AND AVC WITHOUT BESS (UC 2) 151
TABLE 12.8 HW&SW - DSR FOR AVC (UC 3) 152

List of acronyms and abbreviations

You can find in the table below the list of the acronyms and abbreviations used in this document.

Acronym	**Meaning**
A-EMS	Aggregator's Energy Management System
ACER	Agency for the Cooperation of Energy Regulators
aFRR	Automatic Frequency Restoration Reserve
ARERA	Regulatory Authority for Energy, Networks and Environment
AS	Ancillary Services
AVC	Automatic Voltage Control
BAU	Business As Usual
BDE	Bilanciamento Dinamico Energia (TSO's balancing order to aggregators)
BESS	Battery Energy Storage System
BSPs	Balancing Service Providers
CACM	Capacity Allocation & Congestion Management
CAPEX	Capital Expenditures
CBA	Cost Benefit Analysis
CM	Congestion management
CR	Congestion Resolution
CSET	Cyber Security Evaluation Tool
D	Deliverable
DFIG	Doubly Fed Induction Generator
DS	Demand Side
DSR	Demand Side Response
DTR	Dynamic Thermal Rating
EBGL	Electricity Balancing Guideline
EMS	Energy Management System
FFR	Fast Frequency Reserves
FRR	Frequency Restoration Reserve
GSM	Global system for mobile communication
HoD	Hand of Data
HV	High Voltage

HW	Hardware
ICT	Information Communication Technology
JRC	Joint Research Commission
KPI	Key Performance Indicator
MC-CBA	Multi Criteria – Cost Benefit Analysis
mFRR	Manual Frequency Restoration Reserve
MPE	Mancata Produzione Eolica (curtailed wind production)
MSD/ASM	“Mercato dei Servizi di Dispacciamento” (Ancillary Service Market)
MV	Medium Voltage
NC RfG	Network Code on Requirements for Grid Connection of Generators
NIST	National Institute of Standards and Technologies
NRAs	National Regulation Agencies
OHL	Overhead line
PE	Power Electronics
PFC	Power Flow Control
PGM	Power Generating Modules
PNIEC	Piano Nazionale Integrato per l’Energia e il Clima (Italian transposition of the UE Green Deal)
POD	Point of Delivery
PPM	Power park module
PV	Photovoltaic
RAM	Random Access Memory
RES	Renewable Energy Source
ROCOF	Rate Of Change Of Frequency
RR	Restoration Reserve
RTO	Regional Transmission Operator
RTU	Remote Terminal Unit
SAL	Security Assurance Level
SB-DTR	Sensor-based Dynamic Thermal Rating
SCCT	Sistema Controllo, Comando e Conduzione Terna (Terna control system)
SCADA	Supervisory Control And Data Acquisition
SGAM	Smart Grid Architecture Model
SI	Synthetic Inertia
SOGL	System Operation Guideline

SRA	Scalability and Replicability Analysis
SW	Software
TRL	Technology Readiness Levels
TSO	Transmission System Operator
TTC	Total transfer capacity
UC	Use case
UVA	Virtually Aggregated Units
VPN	Virtual Private Network
VPP	Virtual Power Plant
WB-DTR	Weather-based Dynamic Thermal Rating
WP	Work Package
WT	Wind Turbine
WTG	Wind Turbine Generator
Z-EMS	Zonal Energy Management System

0 Executive summary

This document is the deliverable of the Task 5.6. It describes the ex-post market, regulatory, and scalability-interoperability analysis applied to the Italian demo within OSMOSE WP5.

The OSMOSE WP5 addresses the following objectives:

- Improve congestion management on HV grids and maximise RES production by coordinated use of Dynamic Thermal Rating (DTR) short-term forecasts, Power Flow Control (PFC) devices and Demand Side Response (DSR) resources (UC 1);
- Demonstrate, in a relevant HV grid area, the reliability of provision of Synthetic Inertia (SI) and Automatic Voltage Control (AVC) by single or aggregated large wind/solar power plants (UC 2);
- Demonstrate, in a relevant HV grid area, the reliability of provision of Frequency Restoration Reserve (FRR) and AVC by single or aggregated large industrial loads in coordination with traditional power plants (UC 3).

Task 5.6 is subdivided into two sub-tasks:

- subtask 5.6.1, which assesses the effectiveness of market models generated in WP2 with reference to the levels of DSR/RES service availability and reliability observed and analysed in task 5.5. Recommendations about remuneration schemes for synthetic inertia and possible modifications of the regulatory framework in order to ease the market integration of aggregators are also given.
- subtask 5.6.2, which particularly addresses the scalability of the EMS solution developed in the demo with respect to grid extension, number/size of managed resources and cyber-security. Interoperability issues are also analysed for protocol definition.

The document is organized as follows: Section 1 briefly recalls the three use cases of the Italian demonstration project within OSMOSE WP5; Section 2 reports the result of the study conducted in the sub-task 5.6.1: the services covered by the demo project are dealt with in view of market and applicable regulation schemes; Section 3 introduces and describes the proposed approach for the scalability and replicability analysis performed in the sub-task 5.6.2; Sections 4-9 describe the steps of the proposed approach:

- Section 4 defines the functions/applications on which the SRA has been applied
- Section 5 classifies the dimensions (key factors) of the analysis
- Section 6 details the description-based methodology to perform a quantitative SRA applied to the synthetic inertia and automatic voltage control services provided by RES plants and to the ICT infrastructure in view of cybersecurity scalability. It also aims at identifying the benefits of the proposed implementations, and at introducing a simplified CBA applied to the DTR
- Section 7 describes the phase of data and information collection
- In Section 8 the results of the qualitative and quantitative SRA are reported
- Finally, Section 9 discusses the results by formulating recommendation and identifying barriers.

1 Italian DEMO

The Italian demo developed within the WP5 of OSMOSE project consists of three uses cases (UCs):

1. Use case 1: Congestion management by optimal coordination of demand-response and grid devices.
2. Use case 2: Innovative System Services from RES plants.
3. Use case 3: Increasing Availability of System Services from DSR through Aggregation.

1.1 Use cases

A short description of each UC and relevant functionalities is recalled in the following. More details can be found in [1] that reports the results of the demonstration phase. Further details are in the previous deliverables of the WP5 [2]-[11].

1.1.1 Use case 1

Congestion management by optimal coordination of demand-response and grid devices [2]-[3].

Goal*: improve congestion management on HV grid and maximise RES production by coordinated use of Dynamic Thermal Rating, short-term forecasts and Demand Side Response resources.*

The first use case aims to evaluate the potential of two flexibility technologies to resolve congestions on the chosen portion of the HV grid to increase the power supply's security and reduce the curtailment of renewable generation. The two technologies chosen are the Dynamic Thermal Rating (DTR) [7], [11] and the Demand Side Response (DSR) [8]. Furthermore, the software tool PREVEL is used for load forecasting and for providing some meteorological variables required by the DTR [10], [9].

Finally, a management system is required for coordinating and synchronising all these new solutions, optimising their use. The innovative Zonal-Energy Management System (Z-EMS) was implemented at a regional scale in coordination with the existing National Dispatching Center EMS and tested in a real-environment application for ten months [4], [9]-[10].

1.1.2 Use case 2

Innovative System Services from RES Plants [2]- [3], [8].

Goal: *demonstrate, in a relevant HV grid portion, the reliability of provision of Synthetic Inertia (SI) and Automatic Voltage Control (AVC) by single or aggregated large wind/solar power plants.*

The flexibility service analysis is focused on synthetic inertia (SI) and automatic voltage control (AVC). The main result was the derivation of the technical specifications required to size power electronic (PE) devices and to enable aggregation among RES plants. Furthermore, an innovative control scheme for RES SI and AVC provision was implemented and tested.

The number of power plants participating as flexibility providers in the demo was too small to consider aggregation. For this reason, the demo has assessed the reliability of the provision of the services described above only by single power plants.

1.1.3 Use case 3

Increasing Availability of System Services from DSR through Aggregation [8].

Goal: *Demonstrate, in a relevant HV grid portion, the reliability of the provision of Automatic Voltage Control (AVC) and Frequency Restoration Reserve (FRR) by single or aggregated large industrial loads.*

Use case 3 focuses on evaluating flexibility provided by industrial loads in a single or aggregated form. Both AVC (Automatic Voltage Control) and FRR (Frequency Restoration Reserve) services are evaluated. The industrial loads are coordinated with traditional power plants.

The FRR flexibility service was not realized as explained with more details in the following parts.

2 Analysis of services included in the Italian demo

In this section, the network services of Synthetic Inertia, Automatic Frequency Restoration Reserve, Congestion Management, and Automatic Voltage Control are analysed, at the national and European level, from the perspective of the regulatory and market frameworks. Then, based on the performed analysis, conclusions are provided on regulation as well as on the compliance of the proposed services with the market models proposed in WP2.

2.1 Synthetic Inertia (SI)

In this sub-section, an analysis of the regulatory and market frameworks at the European and Italian levels concerning the possibility to provide Synthetic Inertia by means of Renewable Energy Sources (RES) and battery energy storage system (BESS) is provided.

2.1.1 Description

As specified in the guidance document of ENTSO- E [12], the provision of Synthetic Inertia is aimed to preserve system integrity by limiting the initial Rate of Change of Frequency (RoCoF) and frequency excursions during severe frequency events. Moreover, with the aim to distinguish *SI* from *Fast Frequency Reserves (FFR),* ENTSO-E provided the following respective definitions [13]:

> *"Synthetic inertia is defined as the controlled contribution of electrical torque from a unit that is proportional to the rate of change of frequency measured at the terminals of the unit".*
>
> *"Fast-Frequency Reserve is a system service that delivers a fast power change to mitigate the effect of reduced inertial response, so that frequency stability can be maintained".*

Therefore, the concept provided for FFR is more general than SI since it consists of a series of products that can be activated in different ways with the aim to mitigate the effects of reduced inertia systems. More in detail, FFR products are also classified according to the following characteristics [13]:

- FFR activation process;
- FFR control;
- FFR duration;
- FFR activation time (as soon as possible or fixed amount of time).

FFR products can be differentiated according to the activation process/parameter. In particular, four different products have been defined, based on:

1. *frequency deviation* (under-frequency or over-frequency than 50 Hz) to provide FFR;
2. *RoCoF* (df/dt) measurement for Synthetic Inertia;
3. combination of 1 and 2;
4. triggering of a relay signal or circuit breaker position.

Article 2 of the Commission Regulation (EU) 2016/631, establishing a network code on requirements for grid connection of generators, defines SI as "*the facility provided by a power park module or HVDC system to replace the effect of inertia of a synchronous power-generating module to a prescribed level of performance*" [14].

2.1.2 Applied technology

Several authors and projects investigated and classified the capability of fast technologies and DERs to provide fast frequency regulation services. According to studies performed by ENTSO-E and reported in [13], Table 2.1 illustrates the capability of some tested technologies to provide FFR.

Table 2.1 Property of technologies to provide FFR (Source: [13])

CONTROL: A: $K\,df/dt$ (SYNTHETIC INERTIA), B: $K\Delta f$, C: PREDETERMINED POWER PROFILE, D: SYNCHRONOUS INERTIAL RESPONSE

Technology Property	Relay-connected load	Converter-connected load	Wind power	Battery	HVDC EPC	Flywheel converter connected	Synchronous condenser
Activation time	instant	<0.5 s	<0.5 s	<0.5 s	<0.5 s	<0.5 s	instant
Duration	minutes	minutes	10 % for about 10 seconds	minutes	N/A	seconds	seconds
Control	C	B, C	(A) ,B, C	A, B, C	A, B, C	A, C	D
Frequency Up regulation Down regulation	Pload N/A[16]	Pload N/A[16]	10 % Up to the actual power output	Pmax-Pset Pmin-Pset	Pmax-Pset Pmin-Pset	Rated power N/A	N/A

16 In theory, some loads can be increased to provide frequency down-regulation. This is the case for thermal loads, like cooling houses, for example.

Within UC2 of OSMOSE project, the provision of SI has been tested in the following different pilots:

- “Pietragalla” pilot consists of an 18 MW wind power plant (9 x 2 MW turbines), coupled with a 2 MW/MWh Battery Energy Storage System, which provides the SI action;
- “Vaglio” pilot, where SI is provided by means of specific control actions performed through pitch control on a 35 MW wind turbine power plant.

2.1.3 Regulation and Market

The ENTSO-E guideline [12] provides details about the need for SI for frequency regulation and considers, in accordance with the relevant regulations, the possibility to provide SI through power-generating facilities (Art. 21(2.a) of [14]), HVDC systems (Art. 14(1) of [15]) and fast demand response utilities (Art. 30(1) of [16]). In detail:

- Power-generating facilities, Art. 21(2.a) of Regulation (EU) 2016/631 [14]:

  “The relevant TSO shall have the right to specify that power park modules be capable of providing synthetic inertia during very fast frequency deviations”.

- HVDC systems, Art. 14(1) of Regulation (EU) 2016/1447 [15]:

  “If specified by a relevant TSO, an HVDC system shall be capable of providing synthetic inertia in response to frequency changes, activated in low and/or high frequency regimes by rapidly adjusting the active power injected to or withdrawn from the AC network in order to limit the rate of change of frequency. The requirement shall at least take account of the results of the studies undertaken by TSOs to identify if there is a need to set out minimum inertia”.

- Very fast demand facilities, Art. 30(1) of Regulation (EU) 2016/1388 [16]:

> *"The relevant TSO in coordination with the relevant system operator may agree with a demand facility owner or a Closed Distribution System Operator (including, but not restricted to, through a third party) on a contract for the delivery of demand response very fast active power control".*

Since the two pilot plants explored the possibility of providing synthetic inertia through power control of large wind power plans, the Regulation (EU) 2016/631 (NC RfG) is hereby examined. This regulation addresses the specific requirements for connecting generating units to transmission systems. In Article 1, the Regulation specifies that:

> *"this Regulation establishes a network code which lays down the requirements for grid connection of power-generating facilities, namely synchronous power-generating modules, power park modules and offshore power park modules, to the interconnected system".*

According to Article 2(5), the term "power-generating module" or PGM is more general and indicates:

> *"either a synchronous power-generating module or a power park module",*

whereas, a power park module or PPM is defined as (Article 2(17)):

> *"a unit or ensemble of units generating electricity, which is either non-synchronously connected to the network or connected through power electronics, and that also has a single connection point to a transmission system, distribution system including closed distribution system or HVDC system".*

This regulation concerns particularly new PGMs. Indeed, as specified in Article 3(1), such connection requirements should be only to new PGMs considered significant in accordance with Article 5 (after specified), unless otherwise provided. Differently, in accordance with Article 4(2), A PGM shall be considered "existing" if already connected to the network on the date of entry into force of this Regulation or if the final and binding contract for the purchase of the main generating plan has not been finalized by two years after the entry into force of such regulation. However, in specified circumstances, Member State may provide that the regulatory authority could establish whether the PGM has to be considered a new power-generating module or already existing.

Therefore, existing PGMs are not subject to this Regulation, except when:

- in case of a type C or type D PGM (further details about types of PGM will be provided hereafter) has been modified and the relevant system operator, notified by the PGM owner, considers that a new connection agreement is required. Then, the relevant regulatory authority shall decide if in that case a new or a revised connection agreement is needed (Article 4(1.a.i-iii));
- the regulatory authority establishes that an existing PGM must comply with all or some of the requirements of such regulation, following a proposal from the TSO in accordance with paragraphs 3, 4, and 5 (Article 4(1.b)).

The Regulation classifies PGMs into different four types (A, B, C, D) according to the connection point voltage level, synchronous area, and maximum power capacity. Each type of PGM must comply with specific requirements described in the same document. In addition, premise (9) specifies that the significance of PGMs should be defined according to their size and influence on the overall system. In the case of power generating facilities consisting of several synchronous machines able to be run independently, the power capacity shall be evaluated on the capacity of each indivisible unit and not the capacity of the whole facility. Differently, the power size of non-synchronously connected power-generating units regrouped together in order to form a single economic unit and having a single connection point should be assessed on their aggregated capacity [14].

Table 2.2 Characteristics of PGM types for synchronous areas according to EU 2016/631.

PMG Type	**A**	**B**	**C**	**D**	
Voltage level	< 110 kV	< 110 kV	< 110 kV	< 110 kV	≥ 110 kV
Threshold limit	Lower limit capacity from which a PGM is considered of type A	Maximum limit threshold for capacity from which a PGM is considered of type B	Maximum limit threshold for capacity from which a PGM is considered of type C	Maximum limit threshold for capacity from which a PGM is considered of type D	
Continental Europe	≥ 0.8 kW	1 MW	50 MW	75 MW	No limit
Great Britain		1 MW	50 MW	75 MW	
Nordic		1.5 MW	10 MW	30 MW	
Ireland and Northern Ireland		0.1 MW	5 MW	10 MW	
Baltic		0.5 MW	10 MW	15 MW	

Table 2.2 illustrates characteristics in terms of voltage and power size for each type of PGM.

More in detail, as specified in Article 5(2), PGMs are considered of type A if characterized by voltage less than 110 kV and active power capacity equal to 0.8 kW or more. Instead, PGMs of types B, C, and D must have maximum capacity at, or above, the threshold value defined by each relevant TSO in coordination with adjacent TSOs and DSOs in accordance with the procedure described in paragraph 3. Nevertheless, such thresholds assumed for types B, C, and D by relevant TSOs shall be lower than the maximum values specified in Table 2.2. With the aim to help the Member States and relevant TSOs in setting such thresholds, ENTSO-E released an implementation guideline [17] providing further details about criteria and motivations adopted for such parameters.

Nevertheless, in accordance with definitions given in [14], RES interfaced with the electrical grid by means of power converters can be considered as PPM. Therefore, since PPMs are not provided with the inherent capability to limit frequency deviations, as for synchronous PGMs, special countermeasures need to be adopted in order to avoid a larger RoCoF during high RES production. In this sense, Article 2(34) specifies that PPMs and HVDC systems can provide SI to replace the effect of the inertia of synchronous PGMs to a prescribed level of performance. However, this task is explicitly requested for only type C and type D power park modules. In fact, as specified in Article 21(2), concerning the additional requirements for frequency stability of type C PPM:

> *"a) the relevant TSO shall have the right to specify that power park modules be capable of providing synthetic inertia during very fast frequency deviations",*

and

> *"b) the operating principle of control systems installed to provide synthetic inertia and the associated performance parameters shall be specified by the relevant TSO".*

In accordance with Article 22, the same requirements are also applied to type D power park modules.

As a further recommendation, with the aim to support the implementation process of NC RfG, Article 11 established that ACER (the Agency for the Cooperation of Energy Regulators) together with ENTSO-E shall involve stakeholders (having regular meetings) with the aim to identify problems and improvements concerning requirements for grid connection of power-generating facilities. In accordance with this aim, the third edition of the "ACER Report on Monitoring the implementation of the Network Code on Requirements for Generators" [18] was published in December 2020. In this report, ACER investigated the status of implementation of Article 21(2) by inquiring 25 National Regulation Agencies (NRAs), whether type C and type D PPMs have been requested to provide SI.

Furthermore, ACER asked the same NRAs if the operating principle of the SI control system has been included in the proposal for the requirements of the general application submitted by the relevant TSOs.

This survey revealed that, even if most of the NRAs recognized the importance of providing SI during very fast frequency excursions, only TSOs of four Member States exercised the right to impose as mandatory the provision of SI from relevant PPMs. In Spain, although non-mandatory, the provision of SI has been recommended. According to the survey, the Italian TSO specified only the possibility to provide SI without mentioning any detail about the operating principle of the installed control systems. In the remaining states, the relevant TSOs did not exercise this right and, therefore, all type C and type D PPMs should not demonstrate their ability to provide synthetic inertia [18].

By Deliberation 67/2017/R/eel, the Italian Authority has initiated an integration process aimed at fully integrating Regulation EU 2016/631 into the Italian grid code by 27 April 2019. Following consultation processes, which involved the Italian TSO, DSOs, and various stakeholders, Resolutions 384/2018/R/eel [19] and 592/2018/R/eel [20] led to the establishment of the national thresholds (Table 2.3) and requirements for each type of PGM, to be adopted in the new version of the national grid code [21].

Table 2.3 Characteristics of PGM types according to the Italian network code [21].

PMG Type	A	B	C	D	
Voltage level	< 110 kV	< 110 kV	< 110 kV	< 110 kV	≥ 110 kV
Power capacity	0.8 kW ≤ P ≤ 11.08 kW	11.08 kW < P ≤ 6 MW	6 MW < P < 10 MW	≥ 10 MW	No limit

Section 1C.5 of the national grid code [21] focuses on requirements that, in accordance with ARERA Regulations 592/2018/R/eel and 149/2019/R/eel [22], must be met by the following generating units [21]:

- Not yet connected at the date of entry into force of 16 May 2016.
- For which the user has not concluded a final and binding contract for the purchase of the main equipment within twenty-four months of the entry into force of the relevant European Connection Code (17 May 2016).
- Already existing of Type C and Type D, but which have been substantially modified. More specifically, in the case of Power Park Modules, if:
    - The PPM's wind turbines or inverters have been replaced for a capacity equal to at least 10% of the efficient power;
    - The PPM's plant control has been upgraded.

In more detail, the requirements for Type C PGM connected directly to the transmission network and of Type D PGM directly or indirectly connected to the transmission grid have been provided in Section 1C.5. However, regarding the provision of synthetic inertia by PPMs, no specific requirements are provided in this section. Indeed, according to the results of the ACER survey [18] described above, the Italian Regulator does not consider the provision of Synthetic Inertia as mandatory. It only defines the possibility for Type C and Type D PPM to deliver SI without establishing any detail about the specific control to be implemented. Precisely, Section 1C.5.6.5 only specifies the order on which, among other services, SI shall be provided by Type C or Type D units. In particular, PGM's owner shall organize plant protection and control devices with the following decreasing priority order:

- grid and generating unit protection;
- synthetic inertia, where applicable;

- frequency control (active power regulation);
- power limitation;
- power ramp limitation.

However, as noted in the grid code itself, wind and solar power plants directly or indirectly connected to 110 kV (or higher) transmission systems are subject to the requirements established in Annex A.17 [23] and Annex A.68 [24], respectively. However, as pointed out in [23] Annex A.17 is only valid for PPM not equipped with energy storage systems, whose requirements should be provided instead in a different Annex. In addition, A.17 itself makes no reference on the provision of synthetic inertia, but it specifies that wind farms must be equipped with a regulation loop able to provide, in case of low-frequency events (when requested by Terna), an inertial response proportional to the detected frequency deviation. Therefore, in order to provide such contributions of inertia for a predefined time, two solutions are possible:

- by exploiting blades' inertia and decreasing rotating speed (*working zone with power lower than nominal value P_n*);
- by acting on the pitch angle (*constant-power working area*).

Furthermore, as specified, inertia shall be provided when the grid frequency is below a set-point value, by default assumed 49.8 Hz, adjustable in the range [49.5 Hz – 50.0 Hz] in steps of 0.05 Hz. In addition, this power contribution shall be provided with priority over set-points, constraints, and other frequency control services. Also, it shall occur as quickly as possible, without any intentional delay.

This task may be interrupted during Fault Ride Trough events. However, in order to comply with mechanical and electrical constraints of wind turbines, this function will only be activated if the power delivered at the beginning of the transient is higher than a limit value specified by the manufacturer and, in any case, not higher than 30% of the nominal power that can be delivered, P_{nd}.

During the delivery of inertia, a power surplus ranged between 0% and 10% P_{nd}, with a 6% P_{nd} of default, is required.

According to the performed mechanism, if the power surplus has been generated through the *working zone with power lower than nominal value P_n*, the wind turbine rotor must be gradually re-accelerated in order to restore the optimal conditions (“recovery” process) when one of the following conditions occurs:

- the frequency returns above the trigger value;
- the time since the beginning of the transient exceeds an adjustable limit, namely “recovery” time. This time should be adjustable between the range [0s – 30s], with a default value of 10s. This value is consistent with the trigger time of the primary frequency regulation of conventional groups (see Annex A.15 for further details).

In the other case, when power surplus is obtained by operating wind turbines in the *constant-power working area*, recovery is not required. However, the power surplus must comply with the electrical and thermal limits of wind turbines as much as possible and, in any case, must be provided for at least 10s. In addition, subsequent inertia actions can only be provided if the recovery process is ended or if more than 60 seconds have elapsed since the last provision of power surplus. Nevertheless, appropriate frequency filtering is required to implement this feature.

On the basis of this analysis, it was observed that, although the possibility of proving Synthetic Inertia through PPMs and wind power plants is considered feasible, the Italian national grid code still lacks at the moment of a specific regulation on the provision of FFR control actions based on RoCoF signal (what was defined as FFR with control type A in [13]). The fast frequency reserve (FRR) control described and regulated through the Annex A.17 of the national grid code is based on the supply of an inertial response that depends on frequency deviations (type B) and not on the rate of change of frequency. Moreover, FFR introduced by Annex A.17 is applied to under-frequency events only.

Both EU Directive 2016/631 and Italian Grid code (A.17) specifically refer to power generation plants that do not include storage units unless pumping storage is used. Therefore, at the moment, the standardization of SI control requirements appears far to be included in EU national grid codes.

2.2 Automatic Frequency Restoration Reserve

This sub-section provides an analysis of the regulatory and market frameworks at the European and Italian levels about the provision of Automatic Frequency Restoration Reserve (aFRR) service by means of Demand Side Response.

2.2.1 Description

Before describing the existing framework about Frequency Restoration Reserve, a definition of FRR service at the European level is provided. Pan-European standardization for balancing and ancillary services (AS) has been started through the Framework Guidelines on Electricity Balancing of ACER [25], and the Network Codes on Electricity Balancing European Network of ENTSO-E [26]. These network codes, now Regulation EU 2017/2195 [27], were developed with the goal of creating a European marketplace where TSOs of different countries can exchange resources suitable to make generation equal demand. This Regulation also introduces the possibility for new players, such as demand response and RES facilities owners, to take part in this market [28]. As pointed out in [29], similar grid services have different names across European countries. With the aim to compare the frequency services performed in the main European countries, the SmartNet project conducted a survey whose results are illustrated in Table 2.4.

Table 2.4 Comparison of frequency grid services in the European countries (Source: D1.1 SmarNet [30])

Country	Frequency control services		
	Primary	Secondary	Tertiary
Austria	FCR	aFRR	mFRR
Belgium	FCR-R1	FRR-R2	R3-Production
			R3-Dynamic profile
			R3 ICH-Interruptible users
Denmark*	FCR (DK1)	aFRR (DK1)	mFRR (DK1 and DK2)
	FCR-N (DK2 normal op.)		
	FCR-D (DK2 disturbance)		
Finland	FCR-N normal operation	aFRR	--
	FCR-D disturbance	mFRR	
Italy	Primary frequency control	Secondary frequency control	Tertiary frequency control
Norway	FCR-N normal operation	aFRR	mFRR
	FCR-D disturbance		
Spain	FCR	FRR	RR

* Denmark is the only country in Europe that belongs to two synchronous areas: the Continental synchronous area and the Nordic synchronous area; different requirements apply in Western Denmark (DK1) and Eastern Denmark (DK2).

As shown in Table 2.4, the grid service of “Frequency Restoration Reserve” corresponds to the Italian “secondary frequency control”. Then, in order to give a common definition of this service, ACER defined the *Frequency Restoration Reserves* as [25]:

> *operating reserves used to restore frequency to the nominal value and power balance to the scheduled value after sudden system imbalance occurrence. This category includes operating reserves with an activation time typically up to 15 minutes […]. Operating*

reserves of this category are typically activated centrally and can be activated automatically or manually […].

Therefore, the reserve employed to perform the secondary frequency control is the Frequency Restoration Reserve (FRR), which is an operating reserve needed to restore the frequency to the nominal value after a sudden disturbance and replaces the frequency containment reserve if the frequency deviation lasts longer than 30 seconds. Indeed, FRR typically has an activation time ranging between 30 seconds and 15 minutes [30]**.** In addition, another purpose of FRR is also to restore power cross-border exchanges to their programmed set-point values [30].

The Frequency Restoration Reserve can be classified into manual Frequency Restoration Reserve (mFRR) or automatic Frequency Restoration Reserve (aFRR) according to the activation mode [31].

2.2.2 Applied technology

FRR is under the responsibility of TSOs and typically is provided by traditional power plants connected to the transmission grid. Nevertheless, the progressive decarbonization process is leading power system operators to require grid services also from DERs [29]. With this objective, several H2020 projects investigated the capability of some DERs to provide grid services and their participation in the AS market. Table 2.5 shows results obtained by the SmartNet project on the capability of DERs to provide primary and secondary frequency regulation services and Table 2.6 provides an overview of DERs' participation in AS markets of some EU countries [32].

Table 2.5 Capability of some DERs to provide current AS (Source D1.2 SmartNet [32])

Ancillary services		Wind	PV	Stationary Storage: Batteries	Mobile Storage: EVs	CHP	TCL	Shiftable loads: Wet appliances	Shiftable loads: Industrial processes	Curtailable loads
Frequency	**FCR**									
	aFRR									
	mFRR									

FCR: Frequency Containment Reserve
aFRR: Frequency Restoration Reserve (automatic)
mFRR: Frequency Restoration Reserve (manual)

According to the color legend specified in D1.2, the dark green color indicates a very good technical capability to deliver the aFRR, while the dark red color indicates no good capability to provide it [32].

Then, by means of pilot tests, OSMOSE investigated the possibility of 150 kV industrial loads to provide automatic Frequency Restoration Reserve.

Table 2.6 Overview of DERs participation in Ancillary Services Markets (Source [33])

	AS product	Product name	Procurement mechanism	Type of DER
Austria	FCR	Primary Control	Tender	Hydro
	aFRR	Secondary Control	Tender	Demand response, industrial generation, emergency generators, storage, etc.
	mFRR	Tertiary Control	Tender	Demand response, industrial generation, emergency generators, storage, etc.
Belgium	FCR	Primary frequency control (R1-Down and R1–Load (Up))	Tender	Flexible generation and load
	mFRR	Tertiary reserve (R3-DP)	Tender (Yearly and monthly)	DR (Interruptible or downward controllable demand)
Denmark	FCR	Primary Control	Daily auction (DK1/DK2)	CHPs, electric boilers, battery
	aFRR	Secondary Reserve (DK1)	Daily tender (DK2) Bilateral (DK1)	CHPs, electric boilers
	mFRR	Tertiary (Manual) Reserve (DK1 and DK2)	5 year tender (DK2) Daily auction (DK1)	CHPs, electric boilers
Espana	FCR	Frequency containment reserve	Mandatory	All of them (upon approval from TSO) (since December 2015)
	FRR	Frequency restoration reserve	Market	All of them (upon approval from TSO) (since December 2015)
	RR	Replacement reserve	Market/Mandatory	All of them (upon approval from TSO) (since December 2015)
	Other	Deviation management	Market	All of them (upon approval from TSO) (since December 2015)
	Other	Power factor control	Mandatory	All of them
Finland	FCR	Frequency controlled normal operation reserve (FCR-N)	Yearly and Hourly Market/ Bilateral contracts	Medium size industrial and commercial consumers such as a large deep freeze storage pilot, and experimental battery storage systems.
	FCR	Frequency controlled disturbance reserve (FCR-D)	Yearly and Hourly Market/Bilateral contracts	Medium size industrial and commercial consumers such as a large deep freeze storage pilot, and an experimental battery storage system.
	mFRR	Fast disturbance reserve (mFRR)	Regulating Power Market/ Bilateral contracts	100 – 300 MW from DR. Type varies depending on the market but typically medium size industrial and commercial loads.
	Other	Peak load reserve	market	10 MW from one heat pump NA
	Other	Heating load reduction for last reserve. (Pilot)	Bilateral contract between DSO and TSO. (pilot)	About 20 MW aggregated from residential houses.
Norway	mFRR	Fast disturbance reserve (mFRR)	Daily tender, plus additional seasonal market	No limitations as long at the activation requirements are met.

2.2.3 Regulation and Market

Regulation (EU) 2017/2195, which establishes a guideline on electricity balancing [27], was developed with the aim of creating a European market and defining common balancing products and services [34]. As specified in the first paragraph of Article 1:

> *"This Regulation lays down a detailed guideline on electricity balancing including the establishment of common principles for the procurement and the settlement of frequency containment reserves, frequency restoration reserves and replacement reserves and a common methodology for the activation of frequency restoration reserves and replacement reserves".*

In addition, the second paragraph states:

> *"This Regulation shall apply to transmission system operators ('TSOs'), distribution system operators ('DSOs') including closed distribution systems, regulatory authorities, the Agency for the Cooperation of Energy Regulators ('the Agency'), the European Network of Transmission System Operators for Electricity ('ENTSO-E'), third parties to whom responsibilities have been delegated or assigned and other market participants".*

About what concerns the Frequency Restoration Reserve, Article 21 specifies:

> *"By one year after entry into force of this Regulation, all TSOs shall develop a proposal for the implementation framework for a European platform for the exchange of balancing energy from frequency restoration reserves with automatic activation."*

To achieve this goal, several implementation projects have been chosen with the aim to develop and define the methodologies for the procurement of balancing services and products [28], [34]. Among them, "PICASSO" (Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation") is the implementation project approved by all TSOs through the ENTSO-E Market Committee to establish the European platform for the exchange of balancing energy from frequency restoration reserves with automatic activation, in accordance with Article 21 of Regulation (EU) 2017/2195 [35]. Figure 2.1 shows EU State Members and Observes participating in this project.

30 TSOs + ENTSO-E (Observer)		
PICASSO Members (26 TSOs)		PICASSO Observers (4 TSOs + ENTSO-E)
Austria	Hungary	Latvia
Belgium	Italy	Lithuania
Croatia	The Netherlands	Estonia
Czech Republic	Norway	North Macedonia
Denmark	Poland	ENTSO-E
Finland	Portugal	
France	Romania	
Germany	Slovak Republic	
	Slovenia	
Sweden	Spain	
Bulgaria	Greece	
Switzerland	Luxembourg	

Figure 2.1 PICASSO implementation project (as of April 2021) (Source [35])

The main targets of the PICASSO project are the following ones:

- design, implement and operate an aFRR platform that complies with the approved versions of:
    - Electricity Balancing Guideline (EBGL);
    - System Operation Guideline (SOGL);
    - Capacity Allocation & Congestion Management (CACM);
    - Further regulations.
- improve economic and technical efficiency without affecting power system security;
- integrate European aFRR markets.

Following the proposal of ENTSO-E, regarding the implementation of a European platform for the exchange of balancing energy for aFRR [36] by Decision No. 02/2020 [37], ACER approved the "Implementation framework for aFRR Platform" [38]. Such regulation describes the implementation framework for the European platform for the exchange of balancing energy from automatic frequency restoration reserves. In particular, as described in Article 7 of [38], specific requirements must be satisfied by aFRR balancing energy products, summarized in Table 2.7.

Table 2.7 Definition of the standard aFRR balancing energy product.

Product characteristic	**Requirements**
Activation mode	Standard aFRR balancing energy product bid shall be activated automatically.
Minimum quantity and granularity	1 MW.
Maximum quantity	9,999 MW.
Full activation time (indicates "the period between the activation request by the connecting TSO in case of TSO-TSO model or by the contracting TSO in case of TSO-BSP model and the corresponding full delivery of the concerned product" [27]).	• *Current value:* each TSO shall define the full activation time of the standard aFRR balancing energy product for the time period until 17th December 2024 in their terms and conditions for BSPs, in accordance with Article 18 of [27], respecting the FRR dimensioning rules pursuant to Article 157(3) of the SO Regulation [31]. • *Future value:* starting from 18 December 2024, the full activation time of the standard aFRR balancing energy product shall be 5 minutes.
Deactivation period ("means the period for ramping from full delivery to a set point, or from full withdrawal back to a set point" [27]).	Shall not be longer than the full activation time.
Validity period ("means the period when the balancing energy bid offered by the BSP can be activated, where all the characteristics of the product are respected. The validity period is defined by a start time and an end time [27]).	Shall be 15 minutes. The first validity period of each day shall begin right after 00:00 CET. The validity periods shall be consecutive and not overlapping.

Regarding the possibility of providing this service through Demand Response utilities, *"ACER Decision on the Implementation framework for aFRR Platform: Annex I"* [38], in accordance with

Articles 3(1.f) and 3(1.g) of Regulation (EU) 2017/2195, highlights that aFRR "facilitates the participation of Demand Side Response including aggregation facilities, energy storage and RES, establishing a level-playing field for all BSPs, through non-discriminatory and transparent rules for the operation of the aFRR-Platform and the harmonization of the standard aFRR balancing energy product characteristics".

Indeed, as specified by Article 18(4.b) and 18(4.c), each TSO shall:

> *"allow the aggregation of demand facilities, energy storage facilities, and power generating facilities in a scheduling area to offer balancing services subject to conditions referred to in paragraph 5 (c)[1]";*

and

> *"allow 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".*

With regard to Demand Side Response, it allows power system operators to increase the flexibility of the internal energy market, enabling the optimal use of networks. Commission Regulation (EU) 2016/1388 [16] has been established with the aim to harmonize the requirements for connecting large renewable power plants as well as Demand Side Response (DSR) facilities [39] Article 2(1) and Article 2(5) define demand facility and closed distribution system as:

> *demand facility: "means a facility which consumes electrical energy and is connected at one or more connection points to the transmission or distribution system. A distribution system and/or auxiliary supplies of a power generating module do not constitute a demand facility";*

Based on these definitions, the introductive note (8) specifies that:

> *"A demand facility owner or a closed distribution system operator ('CDSO') may offer demand response services to the market as well as to system operators for grid security. In the latter case, the demand facility owner or the closed distribution system operator should ensure that new demand units used to provide such services fulfil the requirements set out in this Regulation, either individually or commonly as part of demand aggregation through a third party. In this regard, third parties have a key role in bringing together demand response capacities and can have the responsibility and obligation to ensure the reliability of those services, where those responsibilities are delegated by the demand facility owner and the closed distribution system operator".*

However, as defined in Article 3(1) of [16], the requirements laid down from this regulation shall be applied to new systems such as:

- new transmission-connected demand facilities;
- new transmission-connected distribution facilities;
- new distribution systems, including new closed distribution systems;
- new demand units, used by a demand facility or a closed distribution system to provide DSR services to relevant system operators and relevant TSOs.

This Regulation also applies to existing units in the cases established in Article 4, such as:

[1] Article 5(c): "The terms and conditions for balancing service providers shall contain the rules and conditions for the aggregation of demand facilities, energy storage facilities and power generating facilities in a scheduling area to become a balancing service provider".

> *Article 4(1,a) - "an existing transmission-connected demand facility, an existing transmission-connected distribution facility, an existing distribution system, or an existing demand unit within a demand facility at a voltage level above 1 000 V or a closed distribution system connected at a voltage level above 1 000 V, has been modified to such an extent that its connection agreement must be substantially revised […]".*
>
> *Article 4(1,b) - "a regulatory authority or, where applicable, a Member State decides to make an existing transmission-connected demand facility, an existing transmission-connected distribution facility, an existing distribution system, or an existing demand unit subject to all or some of the requirements of this Regulation, following a proposal from the relevant TSO in accordance with paragraphs 3, 4 and 5".*

In accordance with Article 28 of (EU) Regulation 2016/1388 itself, demand facilities may offer demand response active (and reactive) power control to relevant system operators and relevant TSOs. To be allowed, these facilities should meet specific requirements relating to the established frequency and voltage operating ranges. In addition, demand units must be able to change their power consumption within a range equal to the contracted value, in accordance with the instructions received from the system operator. This power adjustment shall be performed within a range of time specified by the TSO. In addition, to perform the automatic FRR, in accordance with requirements set in paragraph (l), demand units must be able to receive the frequency control signal sent by the relevant system operator, measure the frequency value, and transfer information.

In Italy, secondary frequency control resources are procured through the Ancillary Service market, called "Mercato dei Servizi di Dispacciamento (MSD)". Only programmable units with an installed capacity greater than 10 MVA, called "relevant units", are eligible to participate in MDS. Therefore, RES (except for hydroelectric plants, which are considered programmable resources) are not admitted. These relevant resources to be able to participate in MSD and provide FRR must meet parameters set by Terna [40] in accordance with UCTE requirements [41], some of which are summarized in Table 2.8.

Table 2.8 FRR requirements for MSD

Procurement	FRR provision is optional, therefore not mandatory. The procurement of FRR reserve is done by the national TSO in the Italian ancillary services market "MSD", where the scheduling resulting from the energy market is modified in order to be compliant with reserve margins and network constraints (minimum reserve margins, network constraints).
Remuneration	The activated energy is remunerated according to a pay-as-bid strategy (€/MWh).
Activation mode	The activation occurs automatically through the signal sent by the central controller of Terna's control station. FRR for regions Sardinia (normally) and Sicily (when not in synchronism with the continent) is performed locally.
Activation time	FRR shall be activated from 0% to 100% in 200 seconds. For Sardinia and Sicily (when non in synchronism with the mainland) in 100 seconds.
Duration time	The capability to provide FRR shall be guaranteed continuously for at least 120 minutes.
Product and provider characteristics	FRR can be only provided by generation units qualified for the provision of such service. Moreover, secondary reserve margins, reserved upon generating units qualified for the provision of the service, must be equal to: - the greater between ±10 MW and ±6% of maximum power, *for thermal units*; - ± 15% of maximum power, *for hydro units.*
Other characteristics	The aFRR is performed by a central controller placed in the control system of Terna. The Sardinia (normally) and Sicily (when not in

	synchronism with the Continent) perform locally the secondary power reserve function.

Up until a few years ago, in Italy, DSR-based resources did not participate in MSD. The only exception was represented by the so-called “interruptible load contracts”, which are dedicated DSR programs aimed to provide the TSO with real-time active power resources for emergency control. More recently, in the context of reforming the Italian energy market, with Deliberation 300/2017/R/eel [42] the Italian authority ARERA opened the MSD market to end-users and distributed energy resources not yet enabled to provide balancing services [43]. Following this Deliberation, the Italian TSO started some pilot projects aimed at verifying:

- the participation in the AS market of demand/ energy storage systems and of not yet qualified units;
- the possibility of aggregating multiple units under the same BSP to participate in MSD;
- the remuneration of not-remunerated ancillary services.

By means of such pilot projects, also DERs may be enabled to provide some AS, such as congestion management, balancing, and tertiary reserve services. However, to get significant power contributions from these resources, an aggregation process may be required. With this aim, the role of the aggregator has been introduced as Balancing Service Provider (BSP). It is responsible for managing Virtually Aggregated Units (UVA) and providing services exchanged on the MSD but does not necessarily correspond to the Balancing Responsible Party (BRP).

DERs can be regrouped as UVA of consumption, generation units, and storage systems, connected to the grid at any voltage level l [44]. UVA can be classified into:

- *Virtually Aggregated Units of Production “UVAP”*, consisting of only non-relevant production units (either programmable or non-programmable), including storage systems also.
- *Virtually Aggregated Units of Consumption “UVAC”*, composed of only consumption units.
- *Mixed Virtually Aggregated Units “UVAM”*, characterized by non-relevant production units (either programmable or non-programmable), including storage and consumption units.
- *Nodal Virtually Aggregated Units “UVAN”*, characterized by voluntary relevant production units and/or non-relevant and eventually consumption units also, even connected to the same node of the national transmission network.

As specified in the Consultation Document of ARERA 322/2019 [45], which contains the main directions in the development of the Italian “Integrated text of the electricity dispatching (TIDE)”, UVAM should be enabled to provide upward and downward regulations for mFRR, Replacement Reserve, balancing, and to solve congestions. Nevertheless, even though the provision of the secondary reserve by means of UVA has not been tested in the initial phase of the experimental pilots [44] in 2021 ARERA issued Resolution 215/2021/R/eel [46]. With this document, the Italian regulator approved the proposal made by Terna to experiment on aFRR services provided by aggregated flexible resources (UVAM). Following the results of this pilot, the integration of DRS-based services in the Italian regulatory framework will be furtherly discussed.

As a conclusion, the analysis carried out in this sub-section has shown that, according to regulation (EU) 2016/1388, TSOs may enable demand facilities to provide demand response active power control for aFRR. Following this regulation, in Italy, specific pilot projects have been approved by ARERA to test the provision of aFRR through demand response units. Therefore, these pilots will be aimed to obtain information useful to define the requirements to be adopted for aFRR service through DSR as well as for regulating the participation and remuneration of demand units in the MSD.

2.3 Congestion Management

This sub-section analyses the regulatory and market frameworks at the European and Italian levels on the possibility of leveraging Dynamic Thermal Rating and Demand Side Response for congestion management.

2.3.1 Description

Congestion management takes place when power transmission lines are congested and therefore, they are not able to transfer power flows according to the market outcomes; through congestion management, power flows are controlled so that power system constraints are not violated [47]. Generally, congestion management consists of two different phases [48]. The first one is performed by system operators in advance by means of different methods, including optimal reconfiguration of transmission networks [49] optimal power flow (OPF) tools taking into account the congestion constraints [50], and coordinated approaches between system operators and generation companies [51]. The second phase, called real-time congestion management, is performed in real-time by system operators with the aim to remove the congestions affecting the power lines and move the whole power system to another safe operating point.

2.3.2 Applied technology

Several technologies could be employed for congestion management and can be classified into either cost or no-cost solutions. The first ones are based on control actions implemented on power grid devices, such as transformer switches, phase shifters, or flexible AC transmission devices (FACTS). In contrast, the second group consists of generation rescheduling or load shedding, implying additional costs for power system management [52].

DTR is a tool that can be employed by the system operator to better estimate power system transfer capability and assess congestions. It allows to obtain less conservative results, safeguarding at the same time power system security. However, congestions can still happen, even if the maximum loadibility has been updated to operating conditions by DTR techniques. In these cases, once all available non-costly control resources have been exploited, the system operator must redispatch power resources. Typically, congestion resolution methods are based on generation redispatch. However, an alternative approach is to modify power flows through DSR-based control actions.

Power system components such as lines and transformers are usually operated under highly conservative static thermal ratings, usually determined on calculations based on average seasonal data. Nevertheless, the need for flexibility in power system operation is leading system operators to adopt time-varying thermal ratings, which can be determined dynamically considering the actual operating conditions of such components. The DTR approach has also been called Dynamic Line Rating (DLR) when applied to power lines [53], [54]. Differently from the “static line rating”, which is based on conventional atmospheric conditions (maximum ambient temperature and no wind), DLR takes into account the actual atmospheric conditions, which could offer better cooling of conductors and then increase capacity and improve safety [54]. A few studies specified that, in the presence of less severe weather conditions, the ampacity of existing lines could be significantly extended up to 100%, or even 200%, thanks to the use of dynamic rating instead of static one (Figure 2.2) [55], [56]. This is a significant advantage since, as specified in [56], even a 5-20% ampacity increase over static ratings is already sufficient to solve operational problems in most ordinary cases. DLR technology represents an economically efficient method to extend power lines' ampacity without having to build new physical infrastructures. Moreover, DLR can also be rapidly implemented on existing power corridors, without the need to program long out of services of the transmission lines to install or maintain the needed technologies.

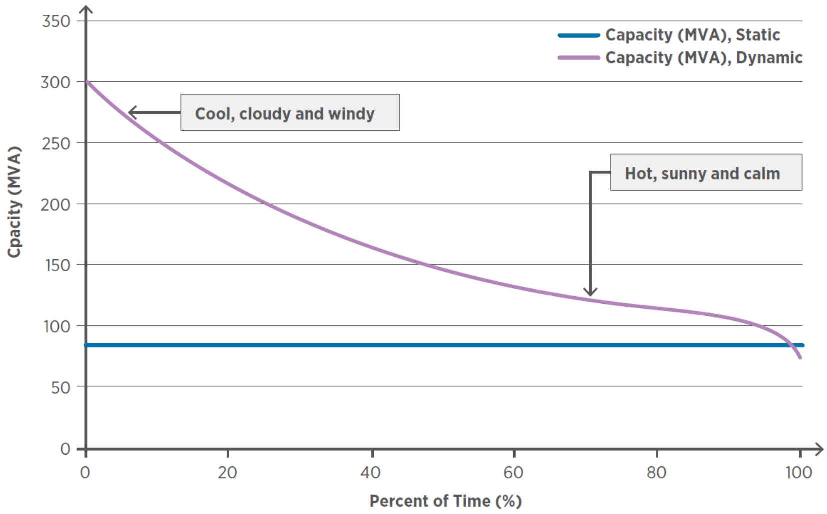


Figure 2.2 Example of comparison between static and dynamic line ratings (source: IRENA [56])

In order to apply DTR to power lines, two different approaches could be implemented [55]:

- "*Contact technologies",* based on measures of physical parameters of conductors, like:
  - conductor's temperature by means of temperature sensors;
  - calculation of sag (through measurements of tension, vibration frequency of conductors, and angle of the line at the span point).
- *"Non-contact technologies"*, based on weather data obtained from meteorological models and/or local sensors, like:
  - calculation of the ampacity;
  - the temperature of conductors;
  - maximum allowed operating time, in case the current carrying capacity of the conductor is exceeded.

The two approaches clearly require different efforts in terms of installation and system modelling. The main advantage of non-contact technologies is that they do not require to de-energize power lines for installation and maintenance; all necessary weather parameters can be directly measured. Nevertheless, the mathematical models to be applied for rating calculations do require adequate validation. On the other hand, contact technologies require the physical installation of sensors on transmission lines by using helicopters or bare-hand installation techniques. As described in [55], several technologies have been adopted at the European level according to the needs and characteristics of each TSO.

Within OSMOSE project, the capability of DTR to improve congestion management and maximize RES production has been tested in UC1. Both sensor-based DTR and weather-based DTR have been tested.

The sensor-based DTR system is constituted by weather sensor stations that measure weather conditions (temperature, humidity, wind speed, solar radiation) and are located in the towers of a transmission line. In the demo, two lines have been monitored using three stations for each line. The sensor nodes (stations) communicate via radio with each other and a master node. The master node is constituted by a dedicated PC located at one terminal substation. During installation, a Micca sensor was used for calibration. The Micca sensor was used only for algorithm calibration and is not permanent (no additional sensors are needed to extend the system to new lines). The master node elaborates the output which is the dynamic rating of the observed line. This rating is expressed as the current, even higher than the rated one, that can be sustained by the line for a certain amount of time.

The weather-based DTR method uses numerous thermo-mechanical parameters of the line, but no physical measurement is needed from the field. The DTR collects weather and power flow forecasts extracted from the PREVEL system and uses such data in an algorithm that is able to estimate the dynamic rating of the observed line. The main advantage of this method is that no sensor installation is required.

In the UC 1 of OSMOSE, the capability to provide congestion management service by means of optimal coordination between demand-response units and grid devices of an industrial park, an oil refinery, a foundry (at 150 kV), and a steel mill (at 220 kV) was tested.

2.3.3 Regulation and Market

Congestion Management through DTR

Regarding DTR strategy, power system technical standards do confirm the possibility of adopting dynamic thermal ratings instead of static ones, and also suggest some methodologies for their calculations.

For example, the document CIGRE Technical Brochure 299, “Guide for Selection of Weather Parameters for Bare Overhead Conductor Ratings”, exhaustively discusses the issue of selecting weather conditions for calculating line ratings. The guidelines offer a practical approach to developing thermal rating estimates to be employed in the design and operation of overhead transmission lines. The guidelines organize the proposed methodologies in four different levels, starting from the most conservative calculation of (static) base ratings. Base ratings can also be evaluated using seasonal data but should be based on an ambient temperature close to the maximum value. Study-based approaches can permit to improve rating through studies that can be conducted with devices that monitor line tension, sag, clearance, or conductor temperature. Ambient-adjusted ratings take into account the possibility of using real-time ambient temperature to update dynamically line ratings, although more conservative assumptions on wind speed are required. As suggested by the technical guide, the TSO may avoid the use of methods based on conservative “worst-case” weather assumptions if real-time monitoring equipment is installed to determine line rating and provided that the monitoring equipment fulfils certain technical requirements on sensitivity, accuracy, and calibration. This less conservative approach should be applied only if, in case of emergency conditions, the system operator has at its own disposal enough real-time resources to reduce line current below the usual standard or enhanced ratings.

Another relevant technical document is the IEEE Std. 738-2012 “Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors”. Differently from the previous document, this standard does not recommend suitable values for weather conditions or conductor parameters for using in line rating calculations. Instead, the document describes a numerical method by which the core and surface temperatures of a bare stranded overhead conductor are related to the steady or time-varying electrical current and weather conditions [57]. The standard provides a detailed thermal model to take into account weather-based information in the extrapolation of thermal rating and proposes a pseudo-code to carry out the numerical calculations. The proposed methodology is also applied to three different system conditions: a) the “Steady-State Case” where the electrical current, conductor temperature, and weather conditions are assumed constant for all time, b) the “Transient Case” where the weather conditions are held constant but the electrical current undergoes a step change, c) the “Dynamic Case” where the conductor temperature is calculated for an electrical current and weather conditions which vary over time.

In the IEEE Std. 738-2012, the adoption of suitably conservative input data for air temperature, wind speed, and wind direction in order to calculate steady-state “book” ratings is explicitly deferred to the CIGRE Technical Brochure 299. The standard does not give recommendations to system operators with regard to the use of static or dynamic ratings as operational limits but rather offers support to better understand and model the physical phenomena. Clearly, it is implicit in the treatment that the adoption of more accurate models can help in reaching less conservative but still secure rating estimates.

Both CIGRÉ and IEEE approaches are acknowledged by the ENTSO-E in [54], a document reporting on the experiences made, in recent times, by TSOs in testing dynamic line ratings and their application to real-time operation. CIGRÉ and IEEE approaches are recognized as the most widely known, with documented experiences made by several TSOs in the applications of their algorithms, either in their original form or in customized implementations. In general, the ENTSO-E remarks that a commonly recognized solution about measurements and algorithms to be employed for DLR has yet to be found. Moreover, the ENTSO-E underlines the need for new improved DLR approaches to be tested in suitable pilot project demonstrations, which can solve some open issues (for example with regard to the uncertainties introduced in the models when the transmission line approaches the maximum temperature around 80° C).

Although the ENTSO-E explicitly points out that DLR should not be a substitute for grid expansion but just a complementary tool to better exploit existing transmission capacity, DLR is recognized as an important instrument to power system operational security. DLR should be employed especially in those countries where overhead high voltage lines have been built 30-40 years ago using maximum design temperature lower than 80° C. Both direct and indirect methods for DLR have been acknowledged, although the ENTSO-E seems to favour the indirect methods since they allow to include in the model also weather and load forecasts to make projections of thermal transients in both short term and long term analyses. Direct methods can instead give an accurate vision of actual conditions of conductors, to be used for short term analysis, although they have the limitation of not being able to describe the behaviour of transmission lines along with their whole extensions (i.e., some local overheating phenomena might be neglected unless the number of measuring points is increased).

Some of the final conclusions made by the ENTSO-E can be relevant to other subsections of this report, in particular with regard to the evaluation of average or maximum increased capacity, for example in cost/benefit analysis. Due to the uncertainties introduced by the multiple atmospheric inputs and by the algorithms, and due to the specificity of the operating conditions that could require the use of enhanced thermal limits, judgments on the effect of DLR could be misleading, if not false. Only real-time operation data obtained through pilot installations over long observation periods can provide a good estimate of the effects of DLR implementations and of the margins to be adopted for security assessment [54].

With regard to the regulatory framework, no specific rules have been defined at the European level for DTR/DLR. The only legal requirement introduced by the EU Regulation (EU) 2015/1222 [58] (“CACM Regulation”), at the Article 27 (4.a), is that “*using the latest available information, all TSOs shall regularly and at least once a year review and update the operational security limits, contingencies and allocation constraints used for capacity calculation*”. However, more explicit directions on line capacity calculations can be found in some recent decisions from ACER.

Since the goal of the CACM Regulation is the coordination and harmonization of capacity calculation and allocation in the day-ahead and intraday cross-border markets, TSOs have to calculate in a coordinated manner the available cross-border capacity. With this aim, the European areas have been classified into specific Capacity Calculation Regions (CCRs) [59], each one characterized by specific proposals for the capacity calculation (see Article 12 and Article 15) made by the involved TSOs. As required by Article 21 of [58] a capacity calculation methodology is developed for each CCR.

With regard to Region 3, “CORE”, Decision no. 02/2019 of ACER [60] established some regulations with regard to the methodologies that CORE TSOs must follow for capacity calculation. According to Annex I “Day-ahead capacity calculation methodologies of the CORE CCR region” [61], thermal limits of critical network elements are expressed in terms of maximum admissible currents which can be calculated either seasonally or adopting a dynamic value that reflects varying ambient conditions. Fixed limits should be adopted instead in those situations where physical limits are not sensitive to external conditions. According to [61] all CORE TSOs shall aim to a gradual phasing out of seasonal limits, replacing them with dynamic ratings, whenever benefits higher than costs are expected. For this reason, at the end of each year, the TSOs of CORE shall analyse all critical network elements characterized by shadow costs higher than zero for more than 0.1% of all market time units. For these elements, a cost-benefit analysis should be carried out to investigate the expected increase in economic surplus resulting from the implementation of dynamic ratings and compare it with the cost of this implementation. In the case of a positive cost-benefit analysis, dynamic ratings should be employed within the next three years. Similar regulations have also been issued for the intraday capacity calculation methodologies (Annex II) [62].

Italian TSO operations, according to [59], befall in the organization of two CCRs: the "Greece-Italy" CCR (concerning the Italian internal bidding zone border and the interconnection with Greece) and the "Italy-North" CCR. With regard to "Greece-Italy" CCR, capacity calculations for day-ahead and intraday market time frame are regulated through the Directive 587/2020/R/EEL of the Italian Regulatory Authority for Energy, Networks and Environment (ARERA) [63]. This Directive approved the capacity calculation methodology proposed in Annex A [64] and Annex B [65]. In the proposed methodology, operational security limits are considered in the total transfer capability (TTC) calculation process for each relevant market time unit. For all critical network elements, the relevant TSO must define a permanent admissible transmission loading value or, where relevant, a temporary admissible value. Limits should be reviewed at least once a year. In Directive 587/2020/R/EEL there is no mention of the methodology to be followed for the assessment of line ratings. Also, the Directive 323/2020 [66] that regulates capacity calculation methodology for the Italy-North CCR does not make explicit reference to the methodology for line thermal rating.

Differently from the CORE Region, capacity calculation methodologies for Italy-Greece and Italy-North CCRs do not make explicit reference to the use of dynamic thermal ratings for network elements. However, DTR/DLR can be easily integrated by the Italian TSO in the TTC assessment methodologies. Advantages related to the adoption of DTR for increasing transfer capacity are recognized by ARERA in the consultation document 542/2017/R/EEL where results obtained by Terna during some DTR experimentations are also acknowledged in terms of both line ampacity limits and avoided wind generation curtailments. According to Terna, by adopting DTR, the ampacity of power lines can be safely increased by 10 % and 30% during the winter and summer periods, respectively. In a generation zone characterized by the massive presence of wind generation, the adoption of DTR on three 150kV lines permitted to reduce generation curtailment by about 50 GWh, reducing annual curtailment costs of about 2-3 Million Euros [67]. On the basis of these premises, through Resolutions 566/2019/R/eel [68] and 567/2019/R/eel [69], the Italian Regulator approved output-based incentivizing mechanisms to be also applied to investments characterized by a low investment intensity, such as in the case of DTR. In particular, the attached technical report [70], in order to promote investments in innovative solutions such as DTR, extended the maximum admissible incentive to the maximum between the investment capital cost and a 10 Million Euros cap for each grid section or subsection.

Congestion Management through DSR

As already remarked in Section 2.2.3, in accordance with (EU) Regulation 2016/1388 [16] demand facilities may offer demand response services to the market as well as to system operators for grid security. In particular, Article 28 sets that:

> *"Demand facilities and closed distribution systems may offer demand response active power control, demand response reactive power control, or demand response transmission constraint management to relevant system operators and relevant TSOs."*

In this sense, Article 2(18) defines 'demand response transmission constraint management' as a demand facility available for modulation by the relevant system operator or relevant TSO to manage transmission constraints within the system. Therefore, demand units are allowed to be controlled for solving grid congestions. However, these resources must comply with the requirements described in [16] and previously summarized.

In Italy, following Resolution 300/2017 of ARERA, the Italian TSO Terna proposed the approval of a pilot project aimed at testing the provision of balancing resources from aggregates of flexible units (UVAM) to the Italian Authority. This pilot project was approved with Resolution 422/2018/R/eel [71]. UVAM are able to provide balancing resources to congestion management and mFRR, even by means of DSR, as long as they are able to increase/decrease power exchanges within 15 minutes by Terna's dispatch order and sustain this power modulation for at least 2 consecutive hours. Following these pilot projects, UVAM and DSR will be integrated into the ordinary organization of the Italian balancing markets.

2.4 Automatic Voltage Control

The last sub-section of this section concerns an analysis of regulatory and market frameworks at the European and Italian level on the provision of Automatic Voltage Control (AVC) by means of Renewable Energy Sources and Demand Side Response.

2.4.1 Description

Voltage control is used by System Operators (SOs) to facilitate the transfer of active power in an economical, efficient, and safe manner across the entire electrical system. However, node voltages depend on reactive power flows through the transmission network. Therefore, SOs control reactive power injections and absorptions to keep system voltages within the operative limits [72].

Due to the symmetry existing between active and reactive power, the grid services employed to perform voltage control are classified similarly to the frequency products [73]. In detail, voltage control can be performed manually or automatically and, in relation to the activation time, the voltage regulation is performed by means of a hierarchical system consisting of the following three different levels:

- *Primary voltage control:* this automatic local control is performed when a voltage deviation from the set-point value is detected. It is activated within milliseconds and can last up to one minute and is aimed to keep the voltage at the point of common coupling close to the reference set-point. AVC is performed by means of a controller, namely “automatic voltage regulator” (AVR), on which the voltage set-point value is established according to several criteria, such as the maximum reactive power that can be provided by each device, as well as droops and security aspects [30].
- *Secondary voltage control:* is performed to regulate the voltage of pilot nodes through the coordination of regional reactive power resources. Thus, when the voltage at these nodes is out of range, the operator changes the voltage set-points of regulators in order to recover the voltage profiles. The response time of this control goes up to one minute and can be maintained for several minutes [30].
- *Tertiary voltage control:* it is performed on a time scale of 10-30 minutes with the objective of optimizing grid operation by minimizing losses, maintaining the required voltage, and the reactive power replacement [30].

Nevertheless, as highlighted in [30], at the European level there is also a lack of homogeneity in naming and requirements for voltage control since, in general, EU countries do not differentiate the voltage control layers. Table 2.9 illustrates the names assigned to the voltage control services in some EU countries.

Table 2.9 Voltage control services in some EU countries (Source [30]).

Country	Voltage control services
Austria	Voltage control
Belgium	Primary control
	Centralised control
Denmark	Voltage control
Finland	Voltage control
Italy	Primary voltage control
	Secondary voltage control
Norway	Voltage control
Spain	Voltage control – Transmission network
	Voltage control – Distribution network

2.4.2 Applied technology

When performing voltage control, reactive power cannot be transmitted over long distances since it would require large voltage gradients [30]. Therefore, voltage regulation is locally managed in accordance with a set-point value. In addition, the progressive decarbonization process and the increasing penetration of RES are leading system operators to procure distributed energy resources to be used for voltage control.

As with frequency services, several H2020 projects have also investigated the capability of some DERs to perform voltage regulation. Within the OSMOSE project, the capability to perform AVC through RES and single/aggregate industrial loads has been evaluated. In particular, in UC2, the provision of voltage regulation service has been tested by both a 35 MW wind power plant and an integrated wind (18 MW) and storage (2MW) plant. Moreover, in UC3, AVC was performed with local tests at an industrial park (220 kV) by a varying (increasing or decreasing) the power factor reference of the three generators (15 kV) to evaluate voltage variations on the transmission grid.

Therefore, an analysis of regulation and market framework about the possibility to use RES and DSR for AVC will be provided in Section 2.4.3.

2.4.3 Regulation and Market

Automatic Voltage Control through RES

Due to the progressive replacement of conventional power units by power converter-based energy sources, the provision of reactive power control for PPMs becomes critical [74]. In accordance with (EU) 2016/631, NC RfG establishes the requirements that synchronous generators and PPMs have to satisfy to provide reactive power control and, then, to perform voltage regulation [14]. In this sense, Article 20 (2) establishes that Type B power park modules shall comply with additional requirements with respect to voltage stability (further details about classification of PPMs have been provided in Section 2.2.3). In more detail, as specified in Article 20 (2.a):

> *"with regard to reactive power capability, the relevant system operator shall have the right to specify the capability of a power park module to provide reactive power"*

Analogously, Article 21(3) for Type C and Article 22 for Type D power park modules establish that:

> *"with regard to reactive power capability, the relevant system operator may specify supplementary reactive power to be provided if the connection point of a power park module is neither located at the high-voltage terminals of the step-up transformer to the voltage level of the connection point nor at the convertor terminals, if no step-up transformer exists. This supplementary reactive power shall compensate the reactive*

power demand of the high-voltage line or cable between the high-voltage terminals of the step-up transformer of the power park module or its convertor terminals, if no step-up transformer exists, and the connection point and shall be provided by the responsible owner of that line or cable".

Furthermore, Article 21(3.b) and Article 21(3.c) specify the reactive power capabilities for Type C and Type D power park modules" by defining sizes of inner envelopes which can be placed in a fixed outer envelope" [74].

Details on what concerns the reactive power control modes of both Type C and Type D PPMs are given in Article 21(3.d). In this sense, as described in the ENTSO-E Implementation Guidance Document (IGD) [74], the following three types of control could be implemented:

- *Voltage control (Voltage Droop) mode*: with a voltage controller proportional to a steady-state voltage error between the target value and the actual one
- *Reactive power control mode:* aimed at maintaining a specified set-point of reactive power at the connection point
- *Power factor control mode:* aimed at releasing power at the connection point with a constant power factor.

Depending on the control mode imposed on the PPM, specific requirements must be met. However, to perform voltage control, both type C and type D PPMs must comply with the parameters shown in Table 2.10.

Table 2.10 PPM requirements for Voltage control (Source: [74])

	value range NC RfG
setpoint voltage	0.95 p. u. – 1.05 p.u.
setpoint voltage stepsize	≤ 0.01 p. u.
deadband	0 – ±5 %
deadband stepsize	≤ 0.5 % of nominal voltage
slope	2 % - 7 %
slope stepsize	≤ 0.5 %
rise time	1 s – 5 s
settling time	5 s – 60 s
steady-state tolerance	≤ 5 % of maximum reactive power

Furthermore, as specified by Article 21(3.d.iv) for type C (and type D) PPM:

"following a step change in voltage, the power park module shall be capable of achieving 90 % of the change in reactive power output within a time t1 to be specified by the relevant system operator in the range of 1 to 5 seconds, and must settle at the value specified by the slope within a time t2 to be specified by the relevant system operator in the range of 5 to 60 seconds, with a steady-state reactive tolerance no greater than 5 % of the maximum reactive power. The relevant system operator shall specify the time specifications".

Therefore, the relevant system operator, in coordination with the relevant TSO and PPMs owner, shall specify which reactive power control shall be performed and the relevant set-points to be applied, as well as what further equipment is required to remotely adjust the set-point (Article 21(3.d.vii)). With this aim, ENTSO-E report “Parameters related to voltage issues” [64] provides guidance for defining parameters to be adopted to perform Voltage Control.

The requirements set by (EU) 2016/631, as specified in Section 2.2 have been adopted by the Italian grid code [21]. In particular, regulations concerning wind and solar power plants connected at the transmission network with voltages equal to or higher than 110 kV are established in Annexes A.17 [23] and A.68 [24], respectively. Additional rules are also provided in Section 1C.5.7 of [21], but they concern data, tests, and simulations needed to verify compliance with grid requirements. However, Annex A.17 [23] applies to wind power plants connected directly or indirectly to 110 kV (or higher) transmission systems that are not equipped with energy storage systems, whose requirements should be provided in a different Annex. In addition, Attachment A.17 should be applied to new units (connected after 16 May 2016) and existing units if:

- the PPM’s wind turbines have been replaced for a capacity of at least 10% of the efficient power;
- the PPM’s plant control has been upgraded;
- if they already met the technical requirements to provide voltage control.

About the control of reactive power, Annex A.17 specifies that:

> *“The power plant in parallel with the network shall be able to participate in the voltage control of the electrical system. This control shall be carried out according to the voltage signal taken from TVs installed in the HV section of the power plant. The voltage set-point shall be communicated from the operator and shall be applied by the single user (local logic), also in real-time (within 15 minutes from the request received by Terna); moreover, the power plant control system shall be arranged so that the value of the reference voltage or of the reactive power exchanged by the power plant can be modulated through a remote control or remote regulation signals sent by an operator located in a remote centre (remote logic)”.*

To verify compliance of PPMs, Section 8.3 of Annex A.17 sets out the requirements to be ensured in terms of P/Q and V/Q capability as well as of reactive power regulation [23]. The main requirements to be met for reactive power control with respect to reactive power or input voltage set points are described below.

Local reactive power regulation

The release or absorption of reactive power from PPM must take place according to the characteristic curve Q=f(ΔV) shown in Figure 2.3, where reactive power output is proportional to the difference between the set-point and the measured HV voltage values.

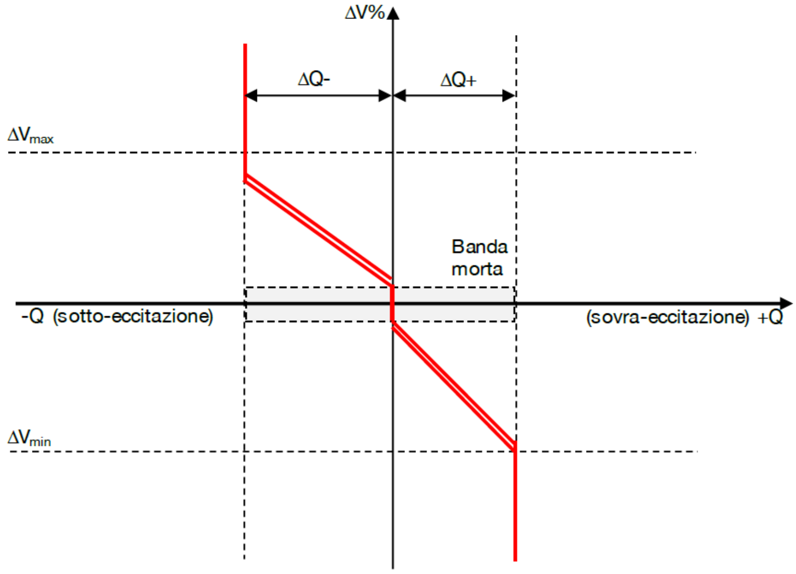


Figure 2.3 Q=f(ΔV) function (Source: [23])

The regulation is based on a voltage set-point V_{rif} communicated in real-time by Terna by means of telephone or remote signals.

Assuming as V_n the nominal voltage of PPM, the minimum range of variability of V_{rif} must be:

$$95\%\ V_n \leq V_{rif} \leq 105\%\ V_n$$

with a variability step of V_{rif} less than or equal to 0.1% V_n, and limit voltages V_{min} and V_{max} established by Terna. However, voltage acquisitions from the field must be done with a minimum sampling of 1 s and, in order to ensure sufficient accuracy on AVR, only voltage measures affected by errors lower than 0.5% V_n are accepted.

Taking into account of dependency of capability limits in over-excitation with the active power, the possibility of managing different slopes between the over-excited and under-excited parts must be foreseen. In this sense, the maximum value required for regulation is 35% P_{nd}.

The control system must allow the implementation of a dead band around the reference voltage when required. Moreover, as specified in the same attached, in order to avoid instability on the local control of reactive power, a closed-loop proportional/integral controller must be implemented if requested from the operator.

However, among other set requirements, Terna established that, following a voltage change ΔV in the network, the power plant must be able to supply 90% of the requested reactive power variation within 2 s and 100% within 5 s, with a precision level ≤5% of the maximum reactive power that can be supplied or ≤ 0.2 MVAr.

Centralized reactive power regulation

The power plant must also be set up to receive a reactive power set-point from Terna by means of adequate communication channels. This reference signal sent by Terna shall be followed up to the system capability limits, with an accuracy greater than 5% of the maximum deliverable reactive power.

However, in order to allow Terna to calculate accurately the signal to be sent to PPM, the power plant will send in real-time, using the same communication channel and at least every 4 s, the reactive power available limit.

In this case, following a variation of the required reactive power ΔQ, the system must be able to deliver 90% of the required quantity within 2 s and 100% within 5 s, with accuracy ≤ 5% of the maximum deliverable reactive power or ≤ 0.2 MVAr.

The requirements set out in A.17 apply only to pure wind power plants. No requirements are provided for wind farms including storage systems which, as stated in the same Annex, should be provided separately. The most recent directives of the Energy Authority are oriented towards the inclusion of voltage regulation among the new ancillary services to be offered by units that are not yet qualified for this type of regulation. In particular, with Resolution 321/2021 [76], the Energy Authority has approved a new pilot project aimed at testing the provision of voltage regulation services by generating units not yet enabled to this type of service, storage systems, and generating units coupled with storage systems. The results obtained from this pilot will be aimed at gathering technical and economic information needed to establish the requirements for such resources and their participation in the AS market.

Automatic Voltage Control through DSR

In accordance with OSMOSE's goal of testing the provision of AVC by means of DSR, Article 28(1) of Regulation (EU) 2016/1388 [16] establishes that demand facilities may offer demand response for active and reactive power control as well as demand response transmission constraint management to relevant system operators. In addition to the requirements set forth in the same regulation (already specified in Section 2.2.3), these facilities must be capable of operating in specific frequency and voltage operating ranges. Moreover, demand units must be able to regulate their power consumption within a range equal to the contracted value, in accordance with the instructions received directly, or indirectly through a third party, from the relevant system operator or the relevant TSO. Moreover, this adjustment of power shall be performed within a time period specified by the relevant system operator or the TSO itself.

Chapter 2 of the Regulation itself also set a series of tests to be performed to investigate the compliance of demand units with the established requirements in terms of active/reactive power control and information exchange.

Following an integration process that began with Deliberation 67/2017/R/eel, Resolution 82/2019/R/eel [77] approved the adoption of Regulation (EU) 2016/1388 into the Italian grid code by 18 August 2019. Section 1C.6 of the national grid code [21] provides the requirements concerning demand units and distribution systems. Such requirements apply to new units or existing ones in the cases already specified in Section 2.1.3 However, the provision of AVC by means of demand units is not specified in the Italian grid code to date. Nevertheless, as explained before, following the Deliberation of ARERA 300/2017/R/eel [42] several pilot projects have been approved with the aim of testing the provision of grid services through demand facilities, energy storage systems, and non-enabled units.

To conclude, in this section, a regulation study has been carried out on the possibility of providing automatic voltage control by means of wind turbines, wind power plants integrating BESS and controllable loads. The European Regulations (EU) 2016/631 and (EU) 2016/1388 allow PGM and demand units to provide reactive power control and, therefore, voltage control service. Nevertheless, Regulations (EU) 2016/631 and (EU) 2016/1388 do not apply to energy storage systems, with the exception of pumped storage. In Italy, according to the requirements specified in the national grid code, which adopts such regulations, wind power plants connected to transmission networks at 110 kV (or more) must be able to provide voltage regulation. In this regard, details are provided by Annex A.17 of the grid code itself. Similarly, demand unit facilities, although regulated by the Italian grid code, are not regulated on the provision of voltage control service. Nevertheless, in pursuing this objective, following ARERA Resolution 300/2017/R/eel, some pilot projects are testing the provisioning of AVC service by means of not yet enable generating units, storage systems, and DSR units. Therefore, the results obtained from these experimental pilots will be employed to establish requirements for the AVC provisioning by means of these resources, currently not yet enabled.

2.5 Compliance of the analysed services with market models

The study performed in this section also examined the compliance of the analysed services with the market model proposed in WP2. Then, taking into account technical and regulatory aspects of each proposed solution, the capability of the analysed services to comply with characteristics of the market design proposals described in Deliverable 2.2 (D2.2) was investigated. In particular, two basic market structures were proposed:

1. Power exchange with zonal pricing;
2. Power pool with nodal pricing.

Deliverable 2.2, based on the current market models, also introduced some additional key elements that should be included in the new zonal and nodal market design. In the following, the compliance with these additional elements is investigated.

Most of the services discussed in this deliverable can be considered parts of the “flexibility products” that have been introduced in Deliverable 2.2. Flexibility is required because of the expected higher gradients of net load due to intermittent energy sources. The procurement of both active and reactive flexible power resources can be based on the exploitation of the DSR and RES controls investigated in activity 5.5. The proposed 5-10 minutes ramping capability should be checked in each case, however, this time requirement seems compatible with all the technologies that have been proposed. In certain cases, for example, when RES/BESS control is adopted, active and reactive power control can rely on very fast activation times. In general, all flexibility products investigated in this section are for sure compatible with the “higher temporal resolution” requirements proposed by D2.2 (a granularity of at least 30 minutes).

“Congestion management” can be improved through the DTR techniques proposed in D5.5. DTR can be applied during capacity calculations when non-costly remedial actions are considered. DTR allows to take into account the actual capacity of power lines and, then, avoid costly remedial actions. RES and DSR control can instead be part of the costly remedial actions to be employed for re-dispatch either as preventive measures or as corrective measures during real-time operation. The “integration of energy and reserves” market is also feasible as long as the procurement of flexible services is made on a day-ahead basis.

This requirement is also necessary to ensure the “co-optimization of energy and reserves” that has been proposed to improve nodal markets. This kind of market is supposed to be able to select the right resource, for the right product, at the right time and price. This kind of approach can theoretically be extended to the flexible resources, although at the moment in the Italian regulation, balancing markets are organized on a pay-as-bid structure. The nodal aggregation of resources is instead already implemented in the Italian structure of flexibility services since flexible products offered by virtual flexible units (so-called UVA) are aggregated using a nodal approach.

Finally, the application of dynamic resources such as storage units or hybrid RES/BESS systems can introduce the “new reserve qualities” proposed by D2.2. In particular, BESS resources can provide the energy-neutral fast reserve control as designed by PJM and proposed in D2.2. Also, DSR applied to prosuming units that have controllable generating units can provide this kind of reserve. It should be remarked, however, that one of the main principles of the new European balancing directives is to promote the availability of asymmetrical reserve products, also allowing the participation to all reserve markets to units that do not have energy-neutral capability (for example pure loads or RES plants without storage).

3 Scalability and replicability analysis of the Italian demo within OSMOSE WP5

3.1 Introduction

Scalability can be defined as the *ability of a system, network or process to increase its size/scope/range to adequately meet growth in demand*.

Replicability denotes the *property of a system network or process that allows it to be duplicated at another location or time* [78]-[80].

Applied to the Italian demo of OSMOSE, the two definitions can be specified by considering their specificities.

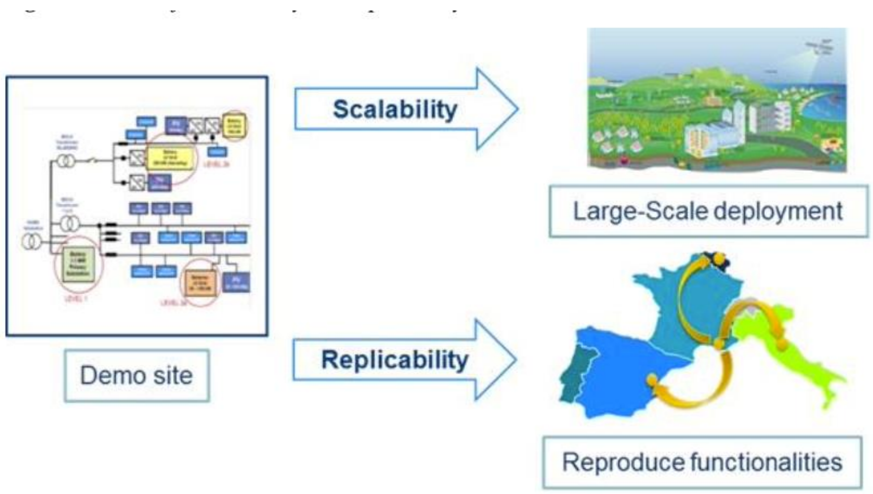
Hence, scalability can be considered in:

- *density*, i.e., more RES, more active customers (DSR), more observed lines (DTR) etc. in the same area of the demo project;
- *size*, i.e., the same solution (use case) scaled up in a bigger area with the same characteristics as the demo area.

While the perimeter of replicability for capturing changes in boundary conditions, especially concerning economic and regulatory aspects, can be considered at:

- *regional (national) level*, i.e., the same solution reproduced in different kinds of networks (different for voltage level, interconnections, etc.)
- *International level*, i.e., the same solution reproduced in other countries with different regulatory frameworks.

In Figure 3.1, the vision for scalability and replicability of the GRID4EU project is depicted [78].



Source: GRID4EU GWP3 partners, "gD3.1" 2013

Figure 3.1 Vision for scalability and replicability of the GRID4EU

3.2 Overview of existing methodologies

Up to now, there is not a very consistent and strictly defined methodology for the SRA conducted in smart grids projects. The SRA within OSMOSE WP5 has been conducted according to the recommendations raised by other related projects:

- BRIDGE [81]

- Grid+ [82]
- Platone [83]
- SuSTAINABLE [84]
- Interflex [85]
- WiseGrid [86]
- GEOFLEX [87].

A brief description of the listed projects and the highlights useful for OSMOSE WP5 SRA have been reported in what follows. Although some of these projects focus on the distribution system, several aspects can be considered relevant also for the OSMOSE demos (more focused on the transmission system).

Particular mention must be reserved to BRIDGE, a European Commission initiative that unites Horizon 2020 Smart Grid and Energy Storage Projects to create a high-level structured view of cross-cutting issues encountered in the demonstration projects and may constitute an obstacle to innovation [81]. Regarding the SRA, a recent effort to provide a set of general guidelines was conducted by the BRIDGE initiative, which launched a dedicated task force to investigate how the different projects were tackling the SRA of the different project results [88]. Such common guidelines to perform SRAs are followed in this document.

GRID+ project [82], which concluded its activities in 2014, had been set up to act as a support team to the European Electricity Grids Initiative (EEGI), implemented by the EU Commission to accelerate innovation in the European electricity networks. From the scalability and replicability point of view, GRID+ conducted extensive research to fine-tune the factors influencing the potential for scalability and replicability and proposed a methodology to be adopted by project managers for a self-assessment of these important features. The method had also been implemented in an online software tool to increase its accessibility. The influencing factors had been classified into three main categories, namely: technical, economic and regulatory (as detailed in the following paragraph 5.1.1) [89]-[90].

The ongoing PLATONE (PLATform for Operation of distribution Networks) project aims to define new approaches to increase the observability of renewable energy resources and of the less predictable loads while exploiting their flexibility. In particular, PLATONE developed an architecture to test and implement a data acquisitions system based on a two-layer approach (an access layer for customers and a distribution system operator (DSO) observability layer) that will allow greater stakeholder involvement and will enable efficient and smart network management. PLATONE analysed the scalability and replicability of the smart grid solutions implemented in the project demos and performed a Multi-criteria Cost Benefit Analysis (MC-CBA) to evaluate and identify the benefits and the beneficiaries of the project from an economic, social and environmental aspect. Through the MC-CBA, the economic viability and sustainability of a project have been assessed by comparing the costs and the expected benefits within a certain time frame (i.e., typically the expected life cycle of the project) [83], [91].

SuSTAINABLE (Smart Distribution System OperaTion for maximising the INtegration of RenewABLE Generation) project, concluded in 2016, was aimed to develop and demonstrate a new operation paradigm, leveraging information from smart meters and short-term localised predictions to manage distribution systems more efficiently and cost-effectively, enabling the large-scale deployment of variable distributed resources. For the large-scale deployment of the SuSTAINABLE concept, scalability and replicability issues have been addressed through questionnaires that allowed identifying the main barriers for deployment of the functionalities, which enabled analysing the implementation conditions in different European regions and proposing mitigation strategies. Besides, the potential impact of the proposed solutions was studied by defining and calculating key performance indicators (KPIs) during the implementation of the designed functionalities and performing a cost benefit analysis (CBA) for the different cases and countries based on the Joint

Research Commission (JRC) methodology and on the boundaries set by regulation as well as scalability and replicability potential [84], [92].

InterFlex project, completed in 2019, investigated the use of local flexibilities to relieve distribution grid constraints. From the scalability and replicability point of view, InterFlex performed technical and non-technical SRA. The technical SRA is considered as the analysis of the system logic and its impact on the network through the use of algorithms, network operation, devices or through the services which relay anew in algorithms. The proposed technical SRA aimed to identify potential barriers and constraints or even drivers of the system concerning the network or the services which are being offered within the demos. The non-technical SRA analysed the drivers and barriers that non-technical boundary conditions may impose onto DSOs and stakeholders' acceptance [85], [93].

WiseGRID project, completed in 2020, proposed a set of solutions, technologies and business models which increase the smartness, stability and security of an open, consumer-centric, European energy grid and provide cleaner and more affordable energy for European citizens through enhanced use of storage technologies and electro-mobility and a highly increased share of RES. The project aimed to deliver the tools and business models that will facilitate the creation of an open market and enable all energy stakeholders to play an active role in a democratic energy transition [86]. In WiseGRID, according to the SGAM framework, a qualitative approach has been applied first to the dimensions of ICT Replicability and Software Replicability, considered most relevant for the project. Each WiseGRID tool was assessed to identify aspects that could potentially impact the replication capability of the tools. The results of the evaluation are presented as a set of conclusions and a list of possible barriers that need to be taken into consideration for the exploitation of the tools and the better replication of them [94].

GEOFLEX project (Generalised Operational FLEXibility for Integrating Renewables in the Distribution Grid) aimed to innovate, integrate and demonstrate existing smart-grid technologies enabling the cost-effective use of energy flexibility in distribution grids for regional energy market actors by (i) increasing the grid's available adaptation capacity, (ii) safely supporting an increasing share of renewable electricity generation, (iii) improving observability and manageability of distribution grid for the use of demand response, and (iv) supporting localised concentration of prosumers DR for DSO to prevent congestion and energy imbalance and avoid investments in transmission and distribution networks [87]. The SRA performed within GEOFLEX is based on all SGAM layers and several identified dimensions, and it is conducted during the whole project by addressing the scalability and replicability issues (i.e., barriers, stakeholder acceptance, etc.) for each investigated use case. They declared that a constant involvement of relevant stakeholders guarantees the optimal implementation of the trials and validation, and evaluation ensures scalability and feasibility beyond the project (e.g., [95]-[96]).

3.3 The proposed approach for the SRA within OSMOSE WP5

The proposed approach to perform the OSMOSE WP5 SRA can be summarised in the following steps:

1. Identification of the subjects of the SRA (topics/items under investigation, as functions vs use cases, demos subdivision, interactions, perimeter, etc.);
2. Identification of affecting factors, i.e., the SRA dimensions;
3. SRA methodology definition and identification of benefits;
4. Data and information collection;
5. Qualitative and quantitative evaluation of the SRA dimensions;
6. Results: recommendations, rules, barriers, etc.

1. The first step aims to define what of the demonstration project is intended to be analysed with the SRA. The WP5 demo is subdivided into three uses cases, and each of them exploits more than one functionality. As detailed in the next chapter, firstly, each elementary function is singularly dealt

with, and the possible interactions between functions are then analysed from the scalability and replicability point of view.

2. The second step includes different sub-steps. Preliminarily, it is necessary to define the backbone of the SRA that should classify the SRA key factors, or more precisely, the SRA dimensions. In the relevant literature, different classifications can be found. The most common is the Smart Grid Architecture Model (SGAM) that subdivides the dimensions of the SRA in the business, function, information, communication and component layers. Other interesting classifications use different terminologies, but some dimension' definitions can be reconducted to the SGAM.

3. The detailed methodology for the assessment, in quantitative or qualitative terms, of each dimension relevant to each subject, should be developed in this step. Moreover, it is necessary to identify the benefits obtainable by the spread development of the proposed functions/uses cases i and if a CBA may complete the SRA. For this goal, potential reference models may be the EPRI and JRC methodologies for CBA, which provide a set of functions that can enable Smart Grid benefits be quantified and eventually monetised, and the multi-criteria CBA methodology proposed by ISGAN [97] - [99].

4. The data and information collection is a crucial step of the whole process. It must engage the partners directly involved in the demos since the set of relevant data can arise only from such players. It should be conducted via surveys and questionnaires directed to the demo leaders. The survey and the collection of questions should deal with items general enough to be relevant to all the functionalities. However, since the elementary functions studied have a certain level of diversity, in addition to the general questions, each partner is called to formulate questions (and answers) relevant to the specific solution/functionality they are involved in.

5. In the SRA dimension evaluation, the data and the information collected in step 4 are analysed for obtaining the target indicators through the methodology defined in step 3. The assessment will be quantitative whenever the data allow a quantitative evaluation; otherwise, it will be qualitative.

6. The last step aims to draw conclusions of the SRA to identify the challenges to be overcome, detect the barriers that may be encountered, and finally give recommendations for rolling out the demos on a large scale. This analysis should recognise the most important aspects affecting scalability and replicability of the technologies or solutions studied (e.g., scaling-up factors, the validity domain for replication and the possible drivers and barriers). In addition, this step may possibly define a timeline and milestones for implementing and exploiting the technologies or solutions evaluated.

The previous steps can be figured out within the steps suggested by the SRA guidelines proposed by the BRIDGE project [88]. The steps proposed in BRIDGE project to perform a proper SRA of a smart grid project are depicted in Figure 3.2. Such overall approach can be broken down into four stages, each of them comprising several steps:

1. Define the scope of the SRA;
2. Define the methodology for each SRA dimension selected;
3. Perform the SRA for each dimension selected;
4. Draw conclusions and deliver the SRA rules/roadmap.

It is worth noticing that such guidelines use the classification of the SRA dimension according to the SGAM that subdivides the dimensions of the SRA into layers (see next section) [100]. Thus, within the SRA scope definition (first stage), the SGAM layers, and within each SGAM layer, the SRA dimensions are selected (this stage includes steps 1 and 2 of the proposed approach). In the second stage, the methodological approach for each dimension selected in the previous stage is defined (it corresponds to step 3 of the proposed approach). The third stage first collects the data and then performs the SRA for each dimension according to the methodology defined in the previous stage (this stage represents steps 4 and 5 of the proposed approach). The last stage consists of analysing the results obtained in the SRA, first for each dimension individually and subsequently trying to relate the results for the different dimensions when relevant among them (this stage is coincident with step 6 of the proposed method).

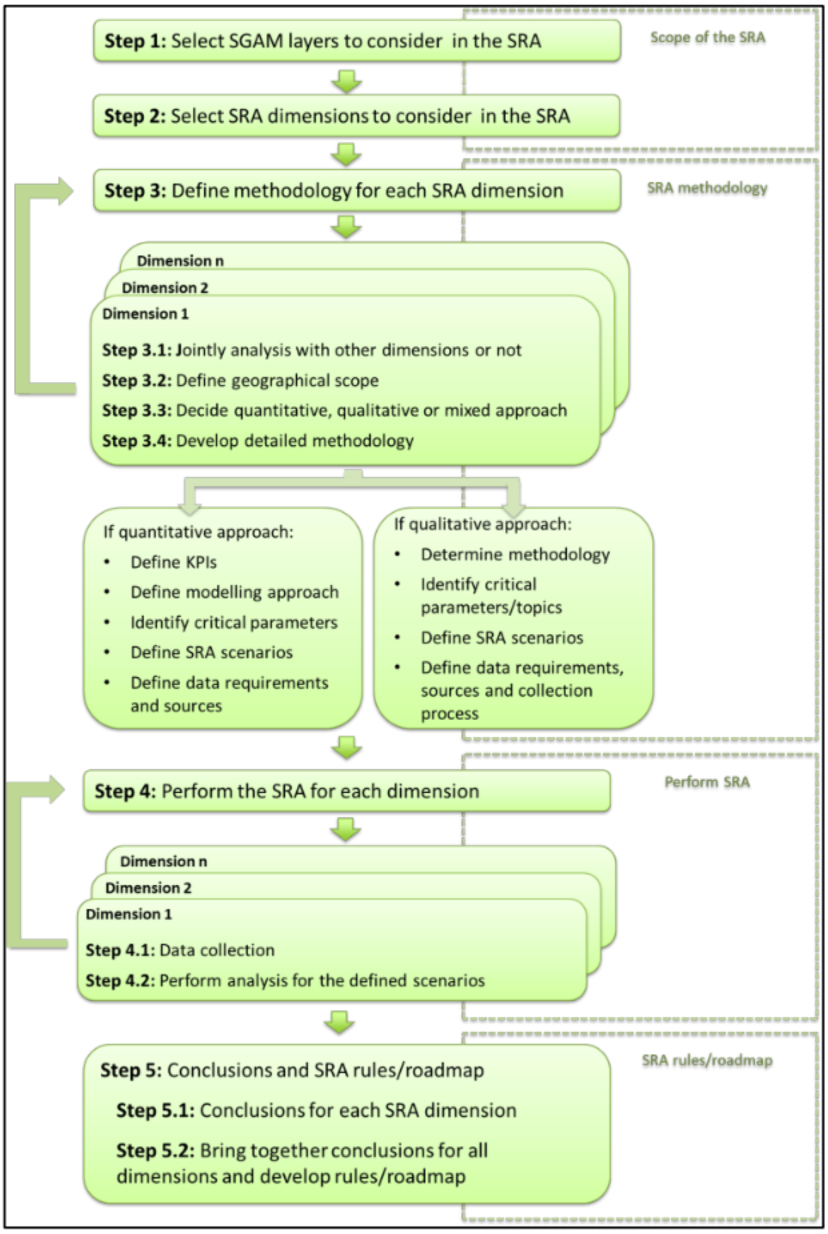


Figure 3.2 SRA guidelines [88]

4 Subjects of the SRA applied to OSMOSE WP5 demos

The SRA has been applied to the three uses cases (UCs) of the WP5 of OSMOSE:

- Use case 1: Congestion management by optimal coordination of demand-response and grid devices.
- Use case 2: Innovative System Services from RES Plants.
- Use case 3: Increasing Availability of System Services from DSR through Aggregation.

The single application/functionality proposed within the OSMOSE WP5 are (in brackets the UC which they refer to):

- Forecasting software - PREVEL (UC 1);
- Dynamic Thermal Rating (UC 1);
- Demand Side Response (UC 1);
- Zonal-Energy Management System (UC 1);
- RES for Synthetic Inertia (UC 2);
- RES for Automatic Voltage Control (UC 2);
- Demand Side Response (UC 3).

Every single technical functionality or technology considered in the UCs are separately studied ; then, the interactions between them are investigated from the SRA perspective.

Furthermore, besides to the cited functions, the cybersecurity issues are analysed in view of scalability and replicability. Such topic can be considered cross-sectional for all the function/use cases and can be deal with separately.

In what follows, a brief description of the considered functionalities and of the topics to which the SRA is applied is reported.

4.1 Functions and topics under investigation

4.1.1 UC1 applications/functionalities

Forecasting software - PREVEL

Power generation from renewable sources and loads needs to be forecasted with a certain level of accuracy. Many of the quantities involved in the study (e.g., PV production, load, and DTR also) are based on weather predictions. PREVEL provides the forecasts of wind speed and direction, temperature, global irradiance, relative humidity, and, by elaborating these variables with a load forecasting algorithm, the active and reactive power forecasts of all electrical loads connected to the 150 and 132 kV grids in the demo area are given. The proposed Numerical Weather Prediction (NWP) is configured for a two-grid nesting so that the finer grid has a resolution of 3 km. In detail, the PREVEL is a software tool implemented in open-source languages (i.e., perl5) and post-processed in R that runs in a multi-core processor. The given outputs are two term forecasting of the exchanged power profiles at the primary substations of the studied zone for two time horizons: i) short-term forecasting of the two next days (a random forest algorithm runs one time a day); ii) very short-term forecasting of the three next hours (algorithm: analog ensemble that runs every 15 minutes). The inputs needed are (i) weather forecasting of temperature and humidity, wind intensity, and surface irradiation for the two next days (resolution of 15 min); (ii) file with the state of the network (from the LISCAL database, a software of the TSO that subdivides the network into subnets,); iii) historical archive of power series (i.e., the power production of wind/solar power plants and load demand).

Dynamic Thermal rating

Usually, the maximum current that can flow through a line is rated on a seasonal basis, considering the worst possible conditions in that region. DTR technology aims at evolving from this approach to one where the lines' limits are rated in real-time.

Two technical solutions are proposed within the OSMOSE WP5 activities:

a. sensor-based DTR (SB-DTR);

b. weather-based DTR (WB-DTR).

The sensor-based DTR is a tool that calculates the dynamic thermal limit of the observed line, starting from the measurements on the field. The measurements can be the environmental parameters from a cooperative group of sensors that measure weather parameters as wind speed, wind direction, pressure, global solar radiation, humidity, or the conductor temperature from the MICCA sensor. The input from the MICCA sensor is used for calibrating the thermal model of the conductor that calculates the conductor temperature by using the more easily measurable environmental parameters from the network of the sensor nodes. Two kinds of input are needed: (i) one structural input that can be provided one time only for each line that has to be observed; (ii) the continuous input from the field, i.e., the environmental conditions and the forecasted current that will flow in the next time interval (15 min). The SB-DTR receives the continuous input from PREVEL and sends its output to the Z-EMS via web (TCP/IP protocol). The communication with the network of sensors is via radio. The given output is the duration curves of the dynamic thermal rating tolerable by the conductors (dynamic limit greater than the static one).

The WB-DTR method uses numerous thermo-mechanical parameters of the line, but no measure is needed from the field. It gains from PREVEL the weather forecasts and the power flow forecast and runs an algorithm that is able to estimate the dynamic rating of the observed line. The main advantage of this method is that no sensor installation is required. From the technical point of view, the WB-DTR is a program implemented in C language that runs in a multi-core processor. Two kinds of input are needed: (i) one structural input that can be provided one time only for each line that has to be observed; (ii) a continuous input with the weather forecasting of a specific location that has to be provided every 15 min. The given output is the duration curves of the dynamic thermal rating tolerable by the conductors (dynamic limit greater than the static one).

Demand Side Response

The industrial customers involved in the OSMOSE project have granted the possibility to tune their loads to offer multiple flexibility services. Five of the involved seven industrial customers participate in the congestion resolution management coordinated by the Z-EMS by offering a theoretical regulating capacity equal to 27.3 MW of demand and 94 MW of production.

Zonal Energy Management System (Z-EMS)

In general terms, an EMS has the role of coordinating and optimising in real-time the use of the tools available to the manager of an energy system and suggesting options and solutions to problems that might occur in the near future according to measures and forecasts. The national transmission grid already uses some EMSs to control the assets in vast areas. The innovative Z-EMS has further and new features :

- it can deal with many flexibility options;
- its actions regard only its controlled zone and cannot negatively impact the rest of the grid (it is separated from the rest of the grid).

It receives information from all the grid assets, power plants and loads in the area. It also includes forecasting methods that enable it to predict consumption, generation from non-programmable sources, and the maximum capacity of the lines (DTR). All these information is then used in an algorithm that is able to detect line congestions and propose actions that would solve them with the minimum cost.

Due to the complexity of its implementation, from the SRA point of view, the Z-EMS has been dealt with as subdivided into elementary components: I) the proper said Z-EMS, ii) the hand of data (HoD) and iii) the dashboard. The HoD communicates with the TSO systems in order to retrieve relevant data and with the other software components involved in the WP5 demo. The Z-EMS dashboard gives to the TSO an interacting interface in order to monitor the congestion management, utilization of DSR and RES plants for the other flexibility services, service order creation and submission.

4.1.2 UC2 applications/functionalities

Synthetic Inertia

By now, production plants connected to the grid via DC/AC converters do not contribute directly to the inertia of the power system. Synthetic Inertia (SI) is a technique that uses power electronics to mimic an inertial response to frequency oscillations so that also these power plants can contribute to the stability of the power system. The demo project involves two wind plants. One of them is equipped with a battery energy storage system (BESS) to provide the inertial contribution independently from WT operating conditions. For the other plant, composed by several DFIG WTs, the project aims at studying and testing the ability of WTs in providing SI by intentionally reducing the rotor speed to extract a part of the kinetic energy and to allow a temporary power injection surplus at the electrical terminals. This is obtainable by controlling internal power electronic devices according to frequency and ROCOF measurements.

Automatic Voltage Control

This technology uses the potential of RES power plants to exchange reactive power (both inductive and capacitive) with the grid with the aim of stabilising voltage levels when required by the TSO. AVC contribution can be required by the TSO by transmitting either a required power exchange set point (referring to the wind plant POD) or a voltage level set point. The two plants provide AVC in different ways. In the case the BESS is installed, it provides AVC, whereas WTs are called to compensate internal reactive absorptions due to MV cables. In the other plant, AVC is directly provided by WTs. A central controller receives the TSO set point and directly controls all the WTs of the plant to regulate the overall reactive exchange at the POD.

4.1.3 UC3 applications/functionalities

Demand Side Response

Balancing service providers (BSP) interact with local controllable resources for modulating active and reactive powers for accounting multiservice provision (congestion management, AVC and FFR). The aim is to focus on the reliability of providing Automatic Voltage Control (AVC) and Frequency Restoration Reserve (FRR) flexibility services in the HV grid section. Regarding FRR, it was not possible to carry out a relevant test campaign because the high thermal inertia of the local resources was not appropriate to quickly and continuously control the power requirements. AVC tests were performed with an industrial park connected to the 220 kV HV grid. The plan was to carry out the tests by sending either V or Q set-points directly from Terna control application to the BSP Gateway via IEC-870-5-104 (*see* chap. 2.3 of D5.3 [8]). Due to emerged technical constraints, it was decided to carry out two types of tests manually. The aim was to identify the maximum potential of the local resources with reference to voltage drop, amount of reactive power and response time.

4.1.4 Cybersecurity

The overall ICT infrastructure of the OSMOSE Italian Demo, described in [9] and tested as reported in [1], includes the ICT assets implementing the data collection, elaboration, communication and storage functionality required by the functional use cases congestion management by coordinated use of Dynamic Thermal Rating (DTR) short-term forecasts and Demand Side Response (DSR), and innovative control of RES and industrial loads.

4.2 Interactions between tools/functionalities

To increase the flexibility and help solve congestion problems of the portion of the grid chosen for the demos, it is necessary that multiple elements and players of the electrical system work together.

The identified interactions are between:

- Z-EMS with DTR, PREVEL, and DSR: the Z-EMS gathers information from the whole area, includes forecasts (about production, loads and DTR), and computes the optimal set of actions needed to solve the detected congestions. The set of actions is then sent to a Central EMS (part of the control system that is already in place on the grid), where the operators can choose whether to implement those actions or not.
- DTR with PREVEL: both WB-DTR and SB-DTR gain from PREVEL the weather forecasts and the power flow forecast and perform algorithms able to estimate the dynamic rating of the observed lines

4.3 SRA perimeter

The approach described in this document refers to the scalability and/or replicability of the demo solutions at the regional and/or national scales for the quantitative analyses and can overcome the national boundaries for the qualitative ones. In details, the quantitative analyses have been focused only on specific technical aspects, thus assuming the same boundary conditions of the demo regarding regulatory aspects and stakeholder acceptance. Instead, the qualitative analyses, conducted by taking into account the information collected with the questionnaire described in the following section 7 can give the opportunity to draw some observations on the replicability of a given functionality abroad (i.e., in the other European Countries).

Few parameters have been considered for analysing the scalability and replicability of the demo solutions. Such parameters may include the network configuration (architecture, type of conductors, extension, and thermal limits), penetration level of RES connected in the network (technologies, size), etc.

For instance, in the qualitative SRA specific issues have been considered:

- Are the proposed solutions still valid if applied to other voltage level grids (i.e., distribution system)?
- Is each technical solution scalable in the whole national territory? Is it replicable in other countries?

The quantitative analysis has been focused on the 2030 PNIEC scenario, and the following question has been addressed:

- How do the relevant SRA dimensions (key factors) vary if the RES penetration levels will increase as expected in 2030 by the PNIEC?

5 Scalability and replicability key factors/dimensions

The identification of the key factors or SRA dimensions should highlight the requirements and the barriers for scalability and replicability of the SRA subjects defined in the previous step.

In what follows, according to the BRIDGE guidelines, the terms SRA "key factors" or SRA "dimensions" have been considered equivalent.

5.1 Dimension classifications

In the relevant literature, more than one categorisation/classification of the SRA influencing factors have been proposed.

Among other categorisations, the scalability and replicability dimensions can be classified according to:

a. the relevant areas [90]
b. the Smart Grid Architecture Model layers [88], [95]
c. technical vs non-technical features [91]

5.1.1 *Classification according to the relevant areas*

Relevant areas proposed by [90]:

- technical area;
- economic area;
- area related to the acceptance and involvement of customers, regulators, authorities, and stakeholders.

The scalability and replicability parameters related to the areas can be subdivided into further subareas and the subareas in factors (Table 5.1 and Table 5.2).

Furthermore, each factor can be considered intrinsic or extrinsic. Intrinsic factors do not depend on the boundary conditions, but their scalability and replicability rely only on the own characteristics of the technical solution. An example of an intrinsic factor is modularity. On the contrary, when the state of the grid, its evolution, or other exogenous items impact the scalability and replicability of the same solution, the corresponding SR factor is considered extrinsic. Examples of extrinsic factors are the one that depends on the penetration level of the renewables, on the number of the expected congestions in a region, or on the regulatory framework implemented.

Table 5.1 Scalability areas and factors

Area	Subareas	Factors/dimensions
Technical	Technology	Modularity (subdivision into independent units)
		Technology evolution (delay between rollout of the original project and the rollout of the scaled-up version)
	Communication, control systems and interface	Interface design (interconnection with other systems)
		Software tools integration
	Infrastructure	Compatibility analysis
Economic	Economies of scale Cost effectiveness	Economies of scale
		Profitability
Acceptance/ involvement	Regulatory issues	Regulatory issues
	Consent by grid users, customers, local authorities and public	Consent

A brief description of the **scalability factors** can be the following.

Technical area

- **Modularity (intrinsic): it** is the basic precondition of scaling. It refers to whether a solution can be divided into interdependent functional units. Clearly defined (and separated) constituent parts may allow the flexibility needed to transfer the setup to a larger scale.
- **Technology evolution (intrinsic):** crucial for considering possible turns in the underlying technology, considered futuristic at the time of the original project. It is related to the TRLs (technology-readiness levels) before and at the end of the OSMOSE project.
- **Interface design (intrinsic**): it tackles how components are connected and how they communicate. It explicitly addresses the number of interactions among components: if such number increases too much with the size of the solution, possible physical problems that lead to unaffordable complexity and requisite redundancy may occur.
- **Software tools integration (intrinsic):** software tools needed to deploy the solution (e.g., simulation models; databases) need to cope with a larger scale without compromising computation effort.
- **Infrastructure, compatibility analysis (extrinsic):** the demo projects, by definition, are applied to a limited area. The existing infrastructures in other areas must be evaluated to verify their affordability to the scaled-up solution's requirements.

Economic area

- **Economies of scale (intrinsic):** in scalable demonstration projects, the increase in costs (in percentage) should be *at most* equal to its growth in size. The project size can depend on the number of customers/plants/lines involved or the amount of managed quantities (e.g., active and reactive power, etc.).
- **Profitability (intrinsic/extrinsic):** on the contrary, the increase of benefits (profit) should be *at least* equal to the percentage increase in project size.

Acceptance area

- **Regulatory issues (extrinsic):** they are related to the readiness to embrace an enlarged project of stakeholders like regulators and policymakers.
- **Consent (extrinsic):** related to the willingness to join an enlarged project of stakeholders like end-users and plants' owners.

Table 5.2 Replicability areas and factors

Areas	Subareas	Factors/Dimensions
Technical	Technology	Standardization
		Interoperability
	Control systems and interface (both software and technology)	Standardization
		Interoperability
	Infrastructure	Network configuration (former: availability)
Economic	Profitability analysis	Macro-economic factors
	Market design analysis (sensitivity analysis)	Market design
	Business model	Business model
Acceptance/ involvement	Regulation	Regulation
	Acceptance	Acceptance

A brief description of the **replicability factors** can be the following.

Technical area

- **Standardization (intrinsic):** the solution itself should conform to published (open) standards for avoiding vendor-specific solutions that may only work properly in a given setting. Furthermore, interface standardization guarantees that a solution may integrate into a new environment in a known and predictable way (e.g., using standard communication protocols).
- **Interoperability (extrinsic):** it ensures the integration of the solution into the specific environment by guaranteeing that the set of standards involved is the same.
- **Network configuration (extrinsic**): this factor refers to elements which are given and cannot be changed within the scope of a project (e.g., climate conditions: temperature, wind, precipitation levels, etc.; territorial characteristics: mountains, lowlands, etc.; local generation mix; demographics: population, ambit, etc.; consumption mix and profiles: households, commercial customers, energy-intensive customers, etc.; size of areas, distances, etc.).

Economic area

- **Macro-economic factors (extrinsic):** an analysis of these factors should aim to assess whether the solution proposed is (still) profitable in other European countries (of interest of the OSMOSE project). Carbon cost, inflation and interest rates have an impact on the costs of a project.

- **Market design (extrinsic):** it is especially crucial for such solutions that imply services not on the market yet. This involves questions on who the players are, what tariffs and whether additional constraints as taxes or subsidy schemes may apply.
- **Business model (extrinsic):** strictly related to the market design, it impacts the viability of the solution by considering, for instance, new market models that do not exist yet, incentives that might not exist in all European countries, etc.

Acceptance area

- **Regulation (extrinsic):** the regulatory regime in the host area should allow the deployment of the replicated project. Different countries have different regulatory frameworks. It is a specific dimension of the international replicability, and it is related to legislative and regulatory tenability of the solution in another context.
- **Acceptance (extrinsic):** as the homologue factor required for scalability, it is related to all the stakeholders that should consent to embrace something that probably is entirely new and not only a larger version of something that already exists.

5.1.2 *Classification according to the Smart Grid Architecture Model layers*

The well-known subdivision in layers of the smart grid architecture model (SGAM) can be effectively applied to the SRA [100]. Figure 5.1 shows the layers (i.e., business, function, information, communication, and component) and Table 5.3 reports the analyses that should be conducted in each layer for a comprehensive SRA. Not all the SGAM layers should be necessarily selected for the SRA. Most SRAs in literature address the functional and business layer, but, for instance, WiseGRID project selected three layers excluding the business model layer because the project performed an extensive analysis of different business models during its develpement [88]. Even the dimensions of each layer to be included in the analysis should be properly identified .

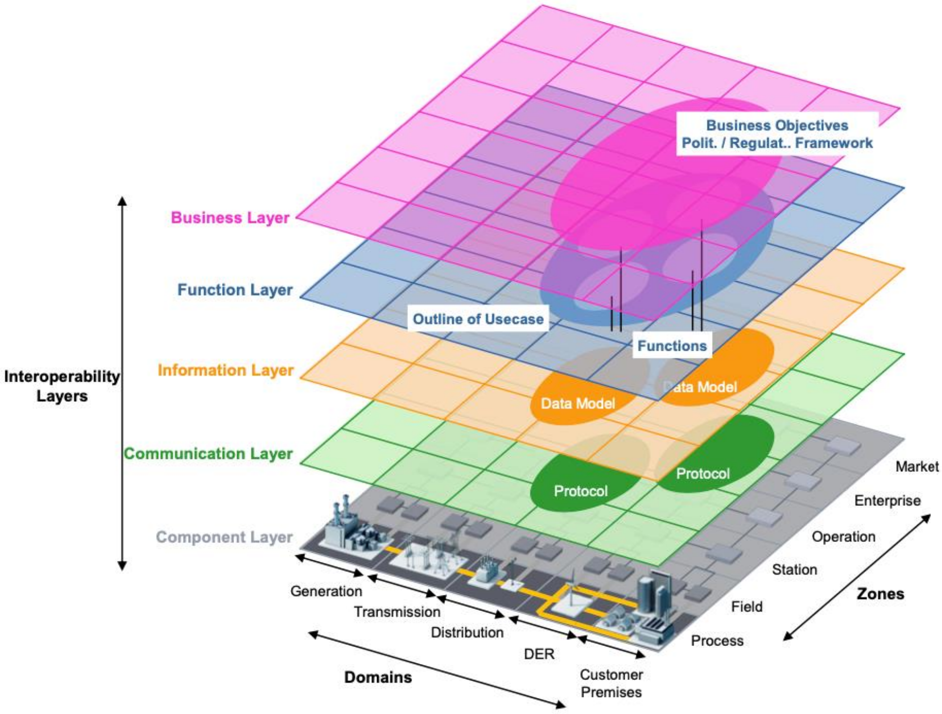


Figure 5.1 SGAM framework

Table 5.3 Smart Grid Architecture Model applied to SRA

SGAM Layers	Scalability and Replicability analysis
Business	Regulatory analysis
	Economic analysis (CBA)
	Business model aspects: market preparedness, market maturity, competition level, ease of doing business
	Stakeholder perspectives
Function	Identification of applied use cases according to demos
	KPI variation
Information	Software scalability
	Software replicability: opensource, libraries, etc.?
	Software interoperability
Communication	ICT scalability: simulation on latency, bandwidth, etc.
	ICT replicability: modularity, standards, open protocols, etc.
Component	Hardware (modularity, standardization, plug and play)

5.1.3 *Classification between technical vs non-technical features*

All the technical features of the solutions implemented in the demonstration projects should be considered in the SRA. The non-technical analyses incorporate boundary conditions different from the technical ones: economic considerations, regulatory framework, and stakeholder acceptance.

The technical analysis can be based on the KPI for measuring the impact of a specific solution in the use cases. For such analysis, models and simulations could be needed:

a. Models should be built for assessing the KPIs under different boundary conditions (i.e., the existing / demo scale boundary conditions and others forecasted/hypothesized that might impact the KPI);

b. Simulation and fine-tuning for validating the models with the results of the demo for a few specific cases.

c. New simulations for performing SRA.

5.2 SRA dimension identification

The above-described SRA factor classifications have many points in common. The SRA analysed in the SGAM classification includes the analysis of all the same dimensions described for the area classification. Thus, the correspondence between the first two classifications can be easily made by considering that all the technical factors of the area classification fall into the function, information, communication and component SGAM layers, and the economic and acceptance areas are covered by the business SGAM layer. In the following Table 5.4, the correspondence between dimensions of the two classifications is reported. Indeed, the third examined classification extends the technical

SRA by including the KPIs. At the same time, the non-technical analysis embraces some dimensions of the economic and the acceptance areas.

Table 5.4 Correspondence table for SGAM and Area classification

Layers	SGAM Dimension	Area classification dimension	Subareas	Area
Business	Regulatory analysis	Regulatory issues Regulation	Regulatory issues Regulation	**Acceptance/ involvement**
	Economic analysis (CBA)	Economies of scale Profitability Market design analysis (sensitivity analysis) Business model	Economies of scale Cost effectiveness Macro-economic factors Market design Business model	**Economic**
	Business model aspects: market preparedness, market maturity, competition level, ease of doing business			
	Stakeholder perspectives	Consent Acceptance	Consent by grid users, customers, local authorities and public Acceptance	**Acceptance/ involvement**
Function	Identification of applied use cases according to demos	Standardization Interoperability Network configuration (former: availability)	Technology Infrastructure Control systems and interface (both software and technology)	**Technical**
	KPI variation			
Information	Software scalability	Software tools integration	Control systems and interface (both software and technology)	
	Software replicability: opensource, libraries, etc.?	Standardization		
	Software interoperability	Compatibility analysis Interface design (interconnection with other systems)		
Communication	ICT scalability: simulation on latency, bandwidth, etc.	Interface design (interconnection with other systems)	Technology Communication, control systems and interface	
	ICT replicability: modularity, standards, open protocols, etc.	Modularity (subdivision into independent units)		
Component	Hardware (modularity, standardization, plug and play)	Modularity (subdivision into independent units) Technology evolution (delay between rollout of the original project and the rollout of the scaled-up version)	Technology Infrastructure	

Not all the dimensions can be significant for all the functionalities of the Italian demo within the OSMOSE WP5, but theoretically, all of them can be analysed from the scalability and replicability points of view. The final list of significant dimensions for each functionality will result from the data collection described in chapter 7 of this report (Data and information collection).

In conclusion, for including all the relevant dimensions, it was decided to merge the mentioned classifications to perform a description based (qualitative) SRA, starting from the most comprehensive list of dimensions of the area classification. Two further analyses on specified functionalities/applications completed the qualitative SRA: i) one aims to evaluate to what extent the services of synthetic inertia and automatic voltage control provision from RES, possibly equipped with BESS, may be scalable in the national territory and to evaluate the scalability of the ICT infrastructure by the cybersecurity point of view, and ii) the second aims to identify the benefits achievable with the implemented functionalities, and to perform a simplified cost-benefit analysis applied to the DTR solution.

6 SRA methodology definition and identification of benefits

In this section the methodology for the SRA dimension assessment and the further analyses conducted on specific functionalities/applications are described.

6.1 Methodology for SRA dimension assessment

The main goal of the SRA is to identify key factors and/or barriers that will face for moving from the demo size toward the large-scale deployment of the tested innovative solutions (i.e., scalability) and for implementing such solutions in other contests (i.e., replicability). The SRA targets are the desired results achievable from the analysis in terms of obstacles or drivers that can help the scalability and replicability of one technical solution. To properly draw the expectations of the SRA, the definition of the subjects and the dimensions of the SRA performed in the previous two steps is fundamental.

In quantitative or qualitative terms, the methodology for the assessment of each dimension relevant to each subject should be able to evaluate the impact of each dimension on the scalability and replicability for avoiding underestimation or overestimation of barriers and drivers, also introducing proper weights.

In [90], the dimensions are weighted, and a weighted sum for each of the three areas (technical, economic, and regulatory) as well as a total weighted sum (over all three areas) are computed. According to the weight, a particular dimension could significantly or minor impact the project demonstrator's scalability and replicability. Finally, a minimum score is established for each factor to avoid incongruence within an area (e.g., a very modular project with very poor interface design should not be directly deemed scalable although the mean score is sufficient). Figure 6.1 inherently suggests specific priorities and a certain order, which could be translated into weights associated with each dimension.

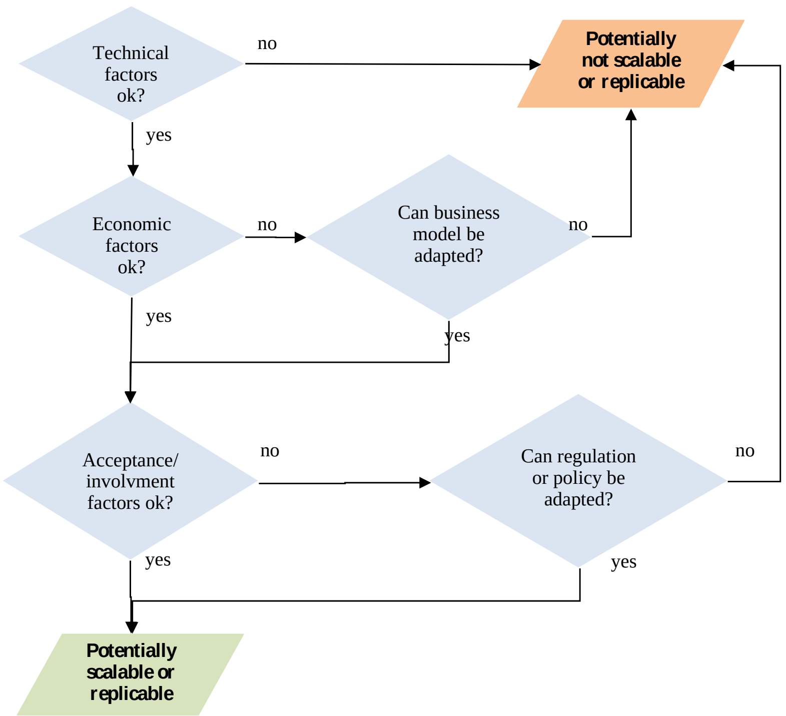


Figure 6.1 The grid+ methodology [90]

Examples of qualitative weights are in [90]:

- **High:** high importance with respect to the other dimensions. The demo solution is poorly scalable or replicable if the dimension is not taken into account. Large costs or complete re-designs are necessary to make the solution scalable or replicable.
- **Medium:** medium importance with respect to the other dimensions. The demo solution is still scalable and/or replicable but only to a limited extent if the dimension is not taken into account. Additional costs could arise in order to overcome these limits.
- **Low:** low importance with respect to the other dimensions. The demo solution is scalable and replicable. However, not contemplating a dimension with low weight implies that a solution could be scaled-up and replicated in a more cost-effective way than in case of taking the dimension into account.

Furthermore, if predefined answers can be formulated, the weights can be easily transformed into quantitative scores (e.g., [90] associates the weights at each considered dimension).

6.1.1 Scores & weights: a description-based method

Extending to the method proposed in [90], a description-based method is applied in the analysis proposed in this report. The method aims at assessing for each subject of the analysis (i.e., the demo functionalities identified in section 4 one numeric indicator of its attitude to be scaled and one other that identifies its property to be replicated. The procedure starts from the data and the information collected from the partner directly involved in the implementation of the demo project (described in the next section 7. Since such an information is derived by the answers to a questionnaire, they are prevalently qualitative. A score & weight method has been developed to compare them in an objective way. It consists of the following steps, applied to each subject:

- Assign **a score** to each dimension (key factor/sub-area), range 1-5 (i.e., from not scalable to scalable with benefits). The score 0 has been added for identifying the case of not relevance of one dimension with the examined solution (not applicable). The score is based on the data and information collected about the dimension in the stage of the methodology described in the next chapter 7 of this deliverable. Such a score should be justified with a comment that follows the answers to the questionnaire.
- Based on a set of defined **weights** (e.g., technical area factors should have greater weights than the acceptance), compute the weighted sums for each area, and sum them for obtaining one **indicator of the scalability** and **one for the replicability** for each function/SRA subject.
- The indicators assessed at the previous step can be compared one to each other for ranking them in terms of scalability and replicability attitudes.

Table 6.1 and Table 6.2 report the scalability and replicability scores used in what follows. It is worth noticing that the zero score does not judge the dimension in terms of scalability or replicability attitudes of the solution but indicates that no information or data have been collected for the specific dimension.

By starting from the qualitative weights proposed in [90], a quantitative weight has been associated at each dimension (Table 6.3 and Table 6.4). The numerical value of weights, between 0 and 1, reflects the importance of a given dimension with respect to the others. Values between 0.8 ÷ 1 indicate a high importance dimension. The score of a medium importance dimension is weighted with 0.5 ÷ 0.7, while 0.3 ÷ 0.4 weight values denote a low importance dimension.

A minimum sum of the weighted scores for each area, corresponding to the score 2 per dimension (i.e., potentially scalable/replicable with barriers), is computed to perform the flow diagram of Figure 6.1. Finally, the indicators, one for scalability and one for replicability, are calculated as the percentage of the maximum weighted sums obtainable by a given application/functionality. The theoretical maximum weighted sums for scalability areas are 20 for the technical area dimensions, 8 for the economic area dimensions, and 5.5 for the acceptance area dimensions; the theoretical maximum weighted sums for replicability areas are 13.5 for the technical area dimensions, 8.25 for the economic area dimensions, and 7.5 for the regulatory area dimensions. However, for avoiding inequities in the calculations, the maximum weighted sums have been rescaled for considering zero scores due to the inapplicability of a given dimension. In detail, the maximum sums of the weighted scores are computed for each solution by disregarding the dimension that gains the zero-score due to the inapplicability of the relevant questions. For instance, if a solution is not influenced at all by a given dimension (i.e., the network characteristics have no role in the HoD operation), the maximum weighted sum obtainable is reduced from the theoretical maximum.

Table 6.1 Scalability scores

Score	**5**	**4**	**3**	**2**	**1**	**0**
Meaning	**Scalable with benefits - No Barriers detected** (i.e., Scalable with benefits means that the scaled-up solution, from the point of view of the analysed factor, is more competitive than the solution to be scaled-up)	**Scalable, no Barriers detected**	**Scalable, but possible barriers detected** Further analyses and verifications needed	**Potentially scalable - Barriers detected** The solution needs to be further developed to overcome the identified barriers	**Not scalable** Due to lack of compliance with specifications or presence of large barriers	**Not applicable/Not assigned** Non relevant to the subject or due to lack of information

Table 6.2 Replicability scores

Score	5	4	3	2	1	0
Meaning	**Replicable with benefits - No Barriers detected** (i.e., Replicable with benefits means that the replication process of the demo, from the point of view of the analysed factor, could increase the competitivity of the solution itself (e.g., replicate the solution could decrease the unitary cost of the solution))	**Replicable, no Barriers detected**	**Replicable, but possible barriers detected** Further analyses and verifications needed	**Potentially Replicable - Barriers detected** The solution needs to be further developed to overcome the identified barriers	**Not Replicable** Due to lack of compliance with specifications or presence of large barriers	**Not applicable /Not assigned** Non relevant to the subject or due to lack of information

Table 6.3 Scalability qualitative and quantitative weights

Area	Key factor/dimension	Weight (qualitative)	Weight (quantitative)
Technical	Modularity	high	1
	Technology evolution	medium	0.6
	Interface design	high	0.8
	Software tools integration	high	0.9
	Compatibility analysis	medium	0.7
Economics	Economies of scale	high	0.9
	Profitability	medium	0.7
Acceptance	Regulatory issues	medium	0.6
	Consent	medium	0.5

Table 6.4 Replicability qualitative and quantitative weights

Area	Key factor/dimension	Weight (qualitative)	Weight (quantitative)
Technical	Standardization	high	1
	Interoperability	high	0.9
	Network configuration	high	0.8
Economics	Macro-economic factors	medium-high	0.75
	Market and business model	high	0.9
Regulatory	Regulatory issues	high	0.9
	Acceptance	medium	0.6

6.2 Further analyses

Besides the description-based analysis above depicted, further studies useful for SRA have been carried out during the task to which refers this report. In particular, two kinds of analyses have been performed on specified functionalities/applications of the Italian demo. The first kind is a quantitative SRA applied to the UC2 functionalities to evaluate to what extent the services of synthetic inertia and automatic voltage control provision from RES, possibly equipped with BESS, may be scalable in the national territory, and to the ICT infrastructure in view to perform the cybersecurity assessment methodology as described in [9]. The second aims, firstly, to identify the benefits achievable with the implemented functionalities, and, secondly, to perform a simplified cost-benefit analysis applied to the DTR solution.

6.2.1 Quantitative SRA applied to UC2 functionalities

This study aims at estimating the benefits achievable at the national level once the solutions implemented in UC2 will be scaled up to larger WTs/BESSs and plants and will be replicated on all the installed wind farms, according to the goals reported in Italy's PNIEC2030 (Table 6.5).

Table 6.5 Wind and PV installed power (October 2020 and PNIEC targets)

	Wind	PV
Installed power (Terna, at 31.10.2020)	10,8 GW	21,5 GW
Additional power according to PNIEC2030	+8,5 GW	+30,5 GW
Total installed power estimated at 2030	**19,3 GW**	**52,0 GW**

For this evaluation, it is important to assume some premises that:

- The technical solution that uses the BESS to provide both SI and AVC is not constrained by the availability of the primary source. As a result, this regulatory contribution can be considered always available in accordance with the BESS sizing, unless the BESS is not used or has been used for the provision of other remunerated ancillary services that undermine its availability to provide SI and AVC.

- The technical solution of providing SI and AVC directly by WTs is subject to a primary source availability study, which is conducted in this analysis. Specifically, experimental results suggest that a WT may only be able to provide SI if its generation coefficient is higher than 30%, i.e., it is generating at least 30% of its rated power. Similarly, reactive power for AVC can be made available for the entire capability area if the WT generation coefficient overpasses 10%.

For characterizing the primary source availability, data have been collected at the province level and then aggregated, according to the flow chart reported in Figure 6.2. Data were obtained from the ENTSO-E transparency platform (annual hourly wind generation aggregated by Italian bidding zones) and from the GSE Statistical Publications (installed power and energy production for each province) [101]-[102]. Both the data refer to a 5 year period (2015-2019).

Once the hourly unit production profiles were obtained for each province, availability hours of each province were estimated by considering only the hours in which the hourly unit production was above the imposed thresholds (30% for SI, 10% per AVC).

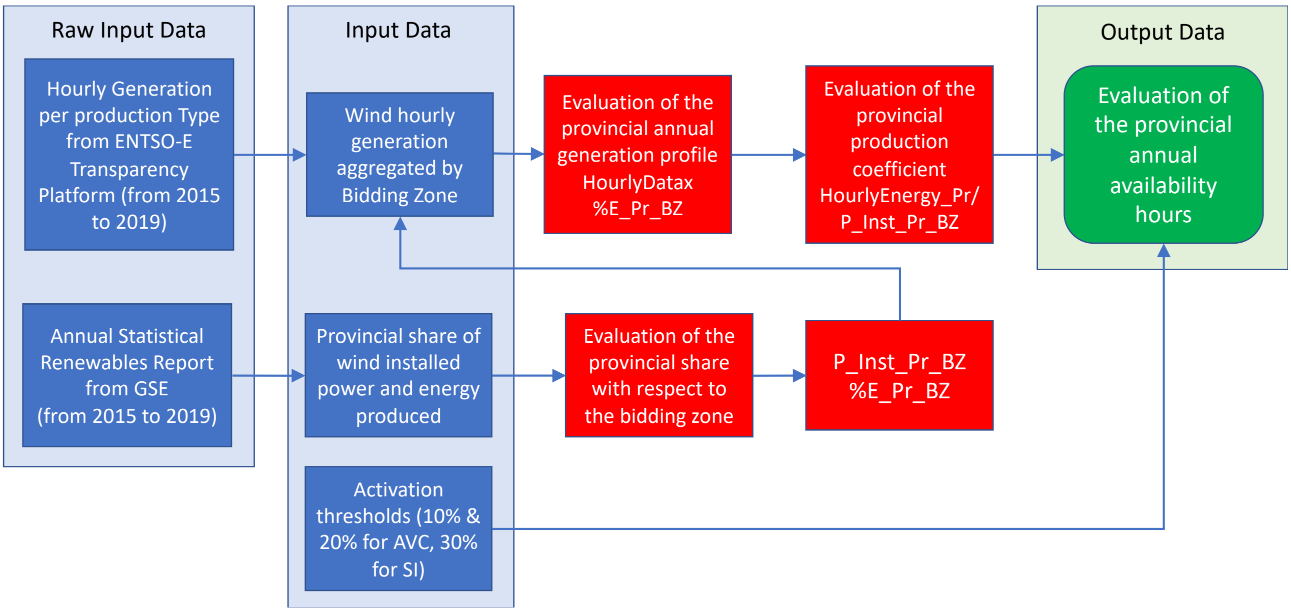


Figure 6.2 Flow chart to evaluate the provincial annual availability for providing SI and AVC if services are supplied by WTs

The results of such a study are reported in the next section 8.3.

6.2.2 Cybersecurity assessment methodology

The cybersecurity assessment methodology of the OSMOSE Italian Demo [9] is based on the Cyber Security Evaluation Tool (CSET®) developed by the US Department of Homeland Security. The tool supports two types of analysis, i.e., standard compliance and architecture analysis, that can be performed either as two sequential steps of a unique assessment process, or as independent analyses.

This first type of analysis identifies a list of prioritised requirements from the NIST 800-53 standard for each control family, that are considered adequate for the SAL assigned to the system. This analysis step provides a rank value for each category of requirements, that allows to identify the critical areas to be focussed on the cybersecurity assessment.

In the second analysis type the main information, communication and operational assets are identified, and the architecture evaluated in terms of vulnerabilities in network and security components. This step derives more specific cybersecurity controls adequate for the criticality levels of the system assets.

The specifications and the results of the application of such a methodology are reported in the next section 8.3.2.

6.2.3 Benefits' identification

The identification of benefits can be useful for different scopes. For the purpose of scalability and replicability analyses, the benefits are fundamental for the estimation of several dimensions, as the ones related to the economic area. For instance, the profitability should consider if the increase in benefits is higher than the increase in project size. Furthermore, in the SRA proposed methodology, the maximum score (i.e., 5) assigned to the answers, both for the scalability and replicability dimensions, refers to solution scalable/replicable with benefits, that means that the scaled-up or the replication of the solution, from the point of view of the analysed factor, is more competitive than the solution itself. As recommended in [90], if a particular project is inherently scalable due to its technical design, but benefits grow slower than costs do when increasing its size, the project is deemed to be potentially not scalable, or it is only partially scalable. Similarly, if a particular project of one country is inherently replicable and its business model focus on a specific benefit, but another country does not incentive such benefit, the project might be potentially not replicable in the other country. Thus, clearly identifying the benefits is a natural task of the SRA.

It is well-known that, once identified, the benefits can be used for performing a Cost-Benefit Analysis (CBA). Such an analysis is one of the most widely used techniques for comparing investment projects in decision-making processes. It is based on the monetisation of the impacts of a project and the inter-temporal discount of costs and benefits. CBA is simple to understand and transparent since it is based on the balance of monetised costs and benefits.

The CBA should evaluate the proposed business models and technical solutions in terms of weighting costs against the corresponding benefits. Although, the monetisation of heterogenous benefits and costs is one of the main shortcomings of CBA, especially when the scale of the project increases. Indeed, for some services potentially provided by the proposed solutions, like the ones with no implemented market yet (i.e., ancillary services provision from RES or customers) or the ones that impact the externalities (i.e., environmental impact of the grid infrastructure), not all the benefits can be easily monetised and, thus, multi criteria-CBA (MC-CBA) might be more appropriate, as proposed by ISGAN in [97]. The level of accuracy of such kinds of analyses will arise from the available data.

Identifying benefits obtainable by the spread development of the OSMOSE Italian demonstration project functions/applications is not straightforward and requires a good deal of thinking for abstracting the single function to the whole demonstration project and associating given benefits to each elementary functionality. Applicable reference models may be the EPRI or JRC methodologies for CBA, which provides a set of functions that can enable smart grid benefits [98]-[99]. However, since it is thought for smart grid projects that deeply include the distribution system, such a list comprises items and features that cannot be applicable at the Italian demonstration project within OSMOSE. Not all the mentioned benefits are covered by the analysed functionalities, and, in turn, some benefits achievable with such functionalities are not perfectly linked with this list.

Another useful source of reference models is the guideline for CBA of grid development projects published by ENTSO-E with the aim of providing a common and uniform basis for the assessment of projects with regard to their value for European society [103]. The principal outcomes of the ENTSO-E CBA guideline represent the main input for the European Commission Project of Common Interest list. However, it can also be used as a source for national CBAs, and Terna and the other European TSOs use it for their Ten-Year Network Development plans (TYNDP).

Some examples of benefits opportunely modified for making them relevant to the Italian demonstration project can be [99]:

- *Increased sustainability* in terms of quantified reduction of carbon emissions, environmental impact of electricity grid infrastructure, quantified reduction of accidents and risk associated with generation technologies (production, installations, etc.).
- *Adequate transmission grid capacity for 'collecting' electric*ity, in terms of maximum allowable injection of power without congestion risks in transmission networks and reduction of energy not withdrawn from renewable sources due to congestion and/or security risks.
- *Satisfactory levels of security and quality of supply* in terms of power system stability and voltage quality performance of electricity grids (e.g., voltage and frequency deviations).
- *Enhanced efficiency and better service in grid operation* in terms of demand-side participation in electricity markets or actual availability of network capacity with respect to its standard value (e.g., net transfer capacity in the transmission grid).

Other benefits also related to the interactions with other countries, and, thus, more relevant to the replicability of the proposed solutions, are [99]:

- Effective support of transnational electricity markets by load flow control to alleviate loop flows and increased interconnection capacities, measurable for instance, with the ratio between interconnection capacity of one country/region and its electricity demand, or with the ratio between monodirectional energy transfers and net transfer capacity, etc.
- Coordinated grid development through common European, regional and local grid planning to optimise transmission grid infrastructure in terms of the impact of congestion on outcomes and prices of national/regional markets, the societal benefit-cost ratio of proposed infrastructure investment, overall welfare increase, time for licensing/authorisation of a new, electricity transmission infrastructure, time for construction (i.e., after authorisation) of a new electricity transmission infrastructure.

In Figure 6.3 the main project assessment categories proposed in [103] are shown. Any project assessment of the national TYNDP should be carried out using the benefit, cost, and residual impact indicators described in the guideline [103].

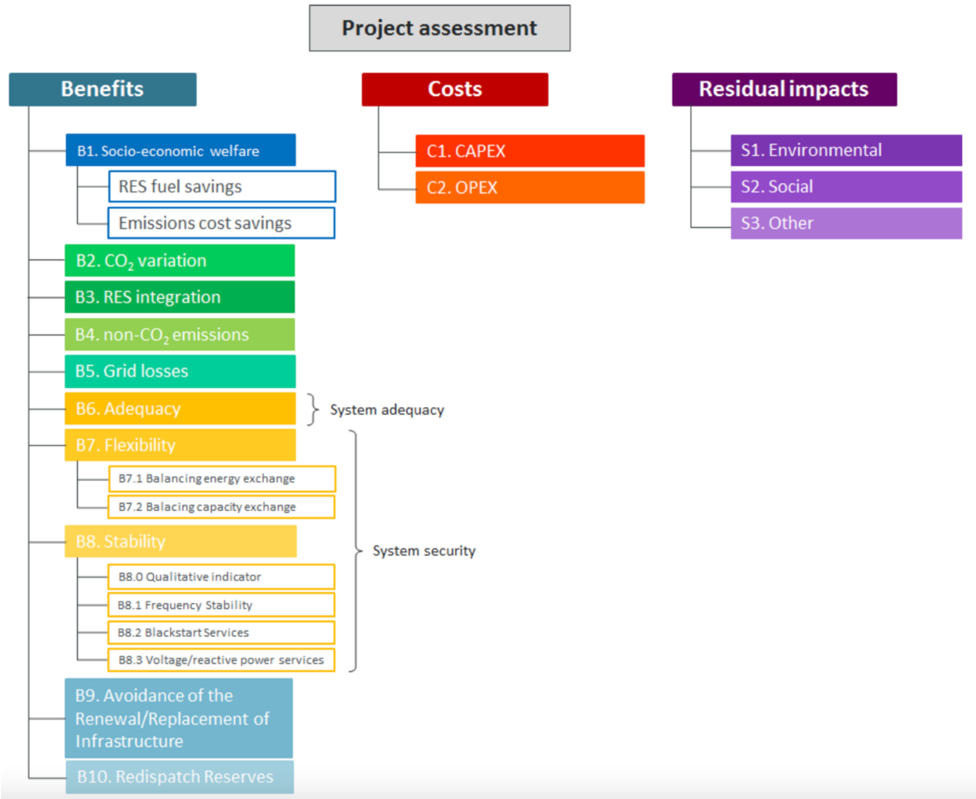


Figure 6.3 Illustration of the project assessment framework categories [103]

Among all the benefits reported in Figure 6.3, some related to the socio-economic welfare, and the system adequacy and security, as well the RES integration are relevant to the demo project of the OSMOSE WP5.

In the JRC guidelines for applying a CBA to smart grid projects [99], the sequence of the following mapping is suggested:

- Assets on to functionalities;
- Functionalities on to benefits;
- Benefits on to monetary values.

Such an approach can be partially used also in the SRA, as the one described in this report. Since the functionalities/services achievable with the experimented assets have been identified as subjects of the SRA, the first step of the proposed mapping is common to the SRA methodology described in the previous paragraphs. Mapping the functionalities on to the benefits is a specific goal of this further study. The results of such a study are reported in section 8.4.

7 Data and information collection

Data and information helpful in evaluating the SRA factors should be provided by the partners involved in the demos. According to many SRAs conducted in previous projects (e.g., [89]), the collection of data and information about the demo project implementation started by designing and sending a survey to the involved partners.

Other sources of information have been the deliverables of the WP and the results of the demonstration phase.

7.1 SRA questionnaire

Each WP5 partner is called to formulate answers and possibly further questions relevant to the solution/functionality they are involved in.

In what follows, according to [89], the questions proposed in the questionnaire are reported. Such questions are general enough to be relevant to all the functionalities. More questions, even tailored to a given functionality, could be formulated.

The answers to the survey are requested to be discursive to give as much information as possible. The partner directly involved in the demo project implementation have been interviewed by the EnSiEL partners for helping in formulating exhaustive answers.

A spreadsheet file with the questions has been proposed in the attachment ([ANNEX-1]). The idea is that each WP5 partner fills the sheets (grey cells) with data and information relevant to the demo solution/functionality they are involved in. The sheets of such file are:

1. **readme**: the sheet includes some instructions and indications for filling the other sheets (reported in the following);
2. **Sheet Solution details**: in this table, details concerning the implementation of the technical solution should be provided.
    - **HW component**: the single HW component of the solution should be listed;
    - **Constituted by:** if the single HW component is constituted by other significant elementary devices, each elementary device should be listed;
    - **Quantity**: the specific quantity related to network/plant/solution element;
    - **HW cost [€]:** specify the cost of the component, or, alternatively, the total cost of the implemented demo (in this case, it is necessary to know is the size of the demo);
    - **SW component:** is it necessary a dedicated (i.e., ad hoc implemented), a commercial, or an open-source SW?
    - **SW quantity**: is it necessary to install the SW in one or more HW positions?
    - **SW cost [€]:** cost of the SW development/implementation or cost of purchasing a commercial SW;
    - **Communication with (protocol):** does the HW o SW component communicate with other components? If yes, what was the protocol used?
3. **Sheet Scalability Q&A:** A minimum number of four questions for each scalability dimension should be proposed. In this sheet, examples of questions, general enough to be relevant to all the functionalities, are proposed.
4. **Sheet Replicability Q&A:** A minimum number of four questions for each replicability dimension should be proposed. In this sheet, examples of questions, general enough to be relevant to all the functionalities, are proposed.

5. **Sheet MC-CBA Q&A:** Questions concerning cost and benefits. Such questions may regard innovation, economics and so on.

Since initially a minimum number of four questions for each SRA dimension was proposed, the ID number of the questions reflect this fact. However, not all partners formulated new questions, but the same ID number originally considered is maintained in the following to avoid any confusion.

7.1.1 *Questions on scalability technical factors (QS1-QS20)*

- **Modularity (QS1-QS4)**

QS1 *Can you easily (technically) add components to your solution to increase your solution's size? If yes, which ones and how? If no, why not?*

QS2 *Are there any limits that affect the proper functioning of the solution or the possible adding extra components within your solution? If yes, explain what the constraint in the technical solution will be.*

…

- **Technology evolution (QS5-QS8)**

QS5 *Do you foresee technological advances in the short to medium term that will make adding components easier (technologically)? If yes, which ones and why?*
QS6 *Can you say something about the TRLs (technology-readiness levels) before the start and at the end of OSMOSE?*
…

- **Interface design (QS9-QS12)**

QS9 *How is the interaction between the components controlled? If control is organized centrally, describe how this is done and indicate which level of centralized control is needed/optimal.*
…

- **Software tools integration (QS13-QS16)**

QS13 *If some components are software products (tools, databases, models, etc.), does the growth of your solution affect their performance (calculation time, etc.)? If yes, how and why? If no, why not? Are there other limits to the software solution (if applicable)?*

…

- **Compatibility analysis (QS17-QS20)**

QS17 *Does the current infrastructure where the project is deployed (outside of your solution) create any limits on the maximum size that can be reached? If yes, what are these external limits, and can they be easily overcome?*

…

7.1.2 *Questions on scalability economic factors (QS21-QS28)*

- **Economies of scale (QS21-QS24)**

QS21 *If the size of the solution increases, how does the cost of your solution?*

…

- **Profitability (QS25-QS28)**

QS25 *Is the actual project economically viable? If yes, what is the main reason for the benefits larger than the costs? If no, why not?*

…

7.1.3 *Questions on scalability acceptance factors (QS29-QS36)*

- **Regulatory issues (QS29-QS32)**

QS29 *Are there any regulations that might drive the uptake of the innovation?*

QS30 *Are there any regulatory barriers concerning the size and scope of the project? If yes, which ones and how do they affect the project's solution?*

QS31 *Do you foresee evolutions (in regulatory frameworks) in the short to medium term that will positively influence the cost-benefit ratio of your solution?*

…

- **Consent (QS33-QS36)**

QS33 *Is stakeholder acceptance important for your project? If yes, explain*.

QS34 *Do you foresee any challenges concerning stakeholder acceptance? If yes, which ones and how could they be overcome?*

…

7.1.4 *Questions on replicability technical factors (QR1-Q12)*

- **Standardisation (QR1-QR4)**

QR1 *Is the solution standards/grid codes compliant? If yes, with which standards (mandatory, voluntary, open, or proprietary)? Could you mention the benefits and/or challenges you expect for being your system/solution compliant with the contemplated standards?*

QR2 *Is the solution easily (economically and technically) made compliant with a defined different set of standards? If yes, describe how? If no, explain why not?*

…

- **Interoperability (QR5-QR8)**

QR5 *Are all components/functions of your solution plug & play, i.e., able to adapt their working and interactions to a different setting? If no, which ones not? If yes, why and how has the plug & play characteristic been obtained?*

QR6 *Can the solution be easily deployed in different environments without additional investment (time/money)? If no, why not? If yes, describe how*

…

- **Network configuration (QR9-QR12)**

QR9 *Does the correct functioning of the solution depend on a natural resource that is specific/abundant in the current environment? If yes, which resource?*

QR10 *Is the functioning of the solution influenced by the specific infrastructure of the location of your demo? If yes, by which aspects?*

QR11 *Is this solution applicable elsewhere? Can your solution be extended to other voltage levels or locations?*

…

7.1.5 *Questions on replicability economic factors (QR13-Q20)*

- **Macro-economic factors (QR13-QR16)**

QR13 *The profitability of the solution, when exported to a different country, depends strongly on the different macro-economic factors. The influence of these factors can typically* *be found via a limited scenario analysis on a few selected target countries. Have you undertaken or do you plan such an analysis?*

QR14 *Can your solution be exported to other countries and still be profitable considering the different macro-economic factors?*

…

- **Market and business model (QR17-QR20)**

QR17 *Is the project still economically viable under a different setting (e.g., other EU member states)? Do you already have plans for exporting your solution abroad? If so, which barriers (economically and regulatory) did you detect?*

…

7.1.6 *Questions on replicability regulatory factors (QR21-Q28)*

- **Regulatory issues (QR21-QR24)**

QR21 *Are there any regulatory barriers concerning the size and scope of the project? If yes, which ones and how do they affect the project's solution?*

QR22 *Does your solution depend on elements of current national or regional regulation necessary for your solution to be feasible and viable? If yes, which ones (describe these elements)?*

QR23 *Are there any barriers arising from the dependency on those elements of current regulation for the feasible deployment of your solution in other environments?*

…

- **Acceptance (QR25-QR28)**

QR25 *Do you foresee acceptance problems when exporting your solution to other countries?*

…

7.2 SR MC-CBA Questions & answers

Furthermore, some questions concerning cost and benefits have been formulated. Such questions may regard innovation, economics, and stakeholders. Table 7.1 reports the questions proposed to the partners. Similar questions have been formulated in interviews addressed to the demo leaders of the OSMOSE project within the WP8. The answers, summarized in the previous section, can be found in [104].

Table 7.1 MC-CBA questions

Innovation	**Q1**	*What is the key innovation of the solution?*
	Q2	*What are the key benefits?*
	Q3	*Who can benefit from the rollout of the innovation?*
Economics	**Q4**	*What are the key costs in a roll-out?*
	Q5	*What type of cost savings are to be expected?*
	Q6	*Have you identified any significant societal or environmental impact of your solution?*
	Q7	*What economic benefits do you expect?*
	Q8	*Are there major remaining technical barriers before a large deployment of your solution?*
	Q9	*Can you say something about the TRLs (technology-readiness levels) before the start and at the end of OSMOSE?*

Stakeholders	**Q10**	*Who will be the key stakeholders (technology investor?) for the rollout of the innovation?*
	Q11	*What will be the main benefits for these stakeholders?*

8 Qualitative and quantitative evaluation of the dimensions

Data and information collected in the previous step are elaborated according to the above-described score & weight method. This step of the proposed procedure aims to analyse the answers of the survey and to evaluate the indicators of the scalability and replicability attributed to the subjects of the SRA.

Furthermore, the results of the further analyses (i.e., quantitative SRA and benefits' identification) conducted during the activities described in this report are reported in the following paragraphs 8.3 and 8.4.

8.1 Preliminarily analysis of questionnaires

Preliminarily, the participation and the number and completeness of the received answers to the questionnaires have been analysed, with the aim of giving an overview to what degree the survey has been successful (i.e., how many answers are missing, how many additional questions have been formulated and so on).

The first remark is that all the involved partners answered to the survey.

8.1.1 Completeness of the answered questionnaire

The first sheet of the questionnaire that asked the solution details has been partially completed by the partners. In Appendix 12, the filled tables for each function are reported. The missing answers are mostly the ones relevant to the cost of the solution.

Concerning the scalability and replicability sheets, the initial number of questions proposed to each partner for the solution of their relevance, differentiated per areas, is reported in Table 8.1. Furthermore, other 11 questions relevant to the cost benefit have been proposed.

Table 8.1 Initial number of questions

	technical	economics	acceptance/regulation
scalability	7	2	5
replicability	7	3	4

Some questionnaires have added questions. In what follows the added questions formulated for certain dimensions and for specific functionalities are reported.

8.1.1.1 Added questions on scalability

In the questionnaires proposed to the partners involved in the DTR implementation the following scalability question has been added.

QR4 *Is there a standard/consolidated model that was considered for modelling the thermal behaviour of the conductors? if yes which one? Which are the validity boundaries of the model?*

In the questionnaires proposed to the partners involved in the DSR implementation (UC1 and UC3) the following scalability questions have been added.

QS3 *Are all components fully interchangeable with others (similar specs but different producers), or specific products are requested? (e.g., RTUs, aggregator platform, ...)*

QS4: *Which is the modulating maximum power in relation to the installation size? Does the modulating maximum power, in relative terms, increase/decrease with the installation size?*

QS7 *In which part of the demo technology evolution is primarily required in order to increase size, performance and competitivity of the solution?*

QS8 *Is the scalability of the solution limited by a lack of TRLs? In which section/part of the plant? Is the modulating power, in relative terms, affected by the controllable load size (it increases or decreases with the component size?)?*

QS10 *When the system has to provide services (CONGESTION MANAGEMENT and VOLTAGE REGULATION), according to which criteria does the control system manage the single controllable loads that are available in the plant? Are these logics affected by the load size or the overall plant size?*

QS14 *Has the software required to manage the solution been fully developed? [Yes, it is fully developed - No, software is partially developed so in-house developed are needed - No, software is not yet developed]*

QS15 *Please indicate how the software required to manage the solution has to be updated/improved to be applied to larger sizes*

QS16 *If some functions are remotely controlled (e.g., the voltage support), does the size of the plant impact the technology to interface the plant with the TSO?*

QS18 *Is there an upper limit in the size of the solution imposed by the specific characteristics of the demo power plant?*

QS19 *Can the development of the solution reduce the lifetime of the controllable load?*

QS20 *Please indicate how the software required to manage the solution has to be updated/improved to be applied to larger sizes*

QS22 *Is the business size large enough to appreciate economies of scale while applying the solution to different kinds of loads? Is there a minimum size under which the regulating function is not suppliable, or is too much expensive to be applied?*

QS23 *Is there a specific size of the solution that could minimize the relative cost of the solution?*

QS26 *Which is the preferred condition in order to provide the service associated with the solution? Choose from the proposed answer. [MANDATORY | MANDATORY + REMUNERATED | VOLUNTARY + REMUNERATED | NO ONE OF THE OTHER (please, provide an alternative in this case)]*

QS27 *In the case the service is mandatory, which is the minimum size above which the service has to be provided. In the case the service is remunerated, which is the remuneration scheme preferred: availability of the service / effective supply of the service / mixed remuneration (in which percentage), etc.?*

QS28 *Can the solution (or part of it) be also used for other purposes (e.g., other remunerated grid services) without compromising the performance?*

QS32 *Do you consider opportune that the service is suppliable only by loads above a minimum size? In terms of size of the single load or of the overall plant?*

QS35 *May the scaling up of the solution improve your reputation, e.g., increase the Environmental Social and corporate Governance (ESG) value, attract new investors…?*

In the questionnaires proposed to the UC2 partners the following scalability questions have been added.

QS3 *Are all components fully interchangeable with others (similar specs but different producers) or specific product are requested? (e.g., BESS, BMS, inverter)*

QS4 *Which is the obtainable SI contribution in terms of maximum power in relation with the WT size? Does the SI contribution, in relative terms, increase/decrease with the WT size?*

QS7 *In which part of the demo, technology evolution is primarily required in order to increase size, performance and competitivity of the solution?*

QS8 *Is scalability of the solution limited by a lack of TRLs? In which section/part of the plant (mechanical/aerodynamic, electrical generation and electronic power conversion, system controller, BESS, etc.)? Is the suppliable contribution, in relative terms, affected by the WT/BESS size (it increases or decreases with the component size?)?*

QS10 *When the system has to provide services (SI or AVC), according to which criteria the control system manages the single WTG that are available in the plant? Are these logics affected by the WT size or the overall plant size?*

QS14 *Has the software required to manage the solution been fully developed?*

[Yes, it is fully developed - No, software is partially developed so in-house developing is needed - No, software is not yet developed]

QS15 *Please indicate how the software required to manage the solution has to be updated/improved to be applied to larger sizes*

QS16 *If some functions are remotely controlled (e.g., the voltage support), does the size of the plant impact on the technology to interface the plant with the TSO?*

QS18 *Is there an upper limit in the size of the solution imposed by the specific characteristics of the demo power plant?*

QS19 *Can the development of the solution reduce the lifetime of WTs? Can the development of the solution reduce the lifetime of the BESS? Which are the key elements (activation thresholds, network frequency perturbations, etc.) impacting on lifetime reduction of WTs and BESS?*

QS22 *Is the business size large enough to appreciate economies of scale while applying the solution to different WT/BESS sizes (considering realistic sizes of WTs and BESS)? Is there a minimum size under which the regulating function is not suppliable or is too much expensive to be applied?*

QS23 *Is there a specific size of the solution that could minimize the relative cost of the solution?*

QS26 *Which is the preferred condition in order to provide the service associated to the solution? Choose from the proposed answer.*

[MANDATORY | MANDARORY + REMUNERATED | VOLUNTARY + REMUNERATED | NO ONE OF THE OTHER (please provide an alternative in this case)]"

QS27 *In the case the service is mandatory, which is the minimum size above which the service has to be provided (in terms of WT size, BESS size, overall plant rated power). In the case the service is remunerated, which is the remuneration scheme preferred: availability of the service / effective supply of the service / mixed remuneration (in which percentage), etc.?*

QS28 *Can the solution (or part of it) be also used for other purposes (e.g., other remunerated grid services) without compromising the performance?*

E.g., in order to provide SI contribution, is a minimum SOC required? How the control system prioritizes the different functions of the BESS (in the case that multiple services are requested simultaneously)?

QS32 *Do you consider opportune that the service is suppliable only by WTs/BESS/plants above a minimum size? In terms of size of the single machine (WT and/or BESS) or of the overall plant?*

QS35 *May the scaling up of the solution improve your reputation, e.g., increase the Environmental Social and corporate Governance (ESG) value, attract new investors…?*

8.1.1.2 Added questions on replicability

In the questionnaires proposed to the partners involved in the DTR implementation the following scalability question has been added.

QR4 *Is there a standard/consolidated model that was considered for modelling the thermal behaviour of the conductors? if yes, which one? Which are the validity boundaries of the model?*

In the questionnaires proposed to the UC2 partners the following replicability questions about replicability have been added.

QR3 *In your opinion, are some characteristics of the components required as a standard in order to facilitate the replication process?*

QR4 *Which is the reliability of the developed solution to provide SI and AVR (excluding the issue related to the primary source availability)?*

QR4b *In a standardized application, which could be an interval of realistic SI gains made available by the WT?*

QR4c *Do you consider that a central coordination of SI contribution made available by each WT by means of a unique controller (which performs the frequency measure at the point of delivery) is an alternative respect to providing SI independently at each WT? Is it possible taking into account limits in terms of communication technologies or others? Which are advantages/disadvantages of this alternative solution?*

QR7 *Which are the drivers that affect the size of the BESS/inverter as regards to the size of the overall wind plant?*

QR10 *Which specs are required to a WT with DFIG generator in order to provide both SI and AVC? Could existing plants made available SI and AVC or are there contributions suppliable only by new installations/revampings?*

QR12 *Could the providing of the solution arise some instability due to the multiple WTs/plants interventions or any other undesired effects? Which specs are required to WTs/BESS in terms of measuring devices and machines to avoid instable behaviours of the grid (e.g., which spec are required to frequency/ROCOF measurement to assure that SI contributions are similar and synchronized)?*

QR12a *Do you foresee that in the future (e.g., the Terna CEN scenario) the functions proposed by demos are necessary to ensure a reliable operation of the power system?*

QR12b *For evaluating the demo performances and their impact on network stability in the case the solution is widely replied, which is the set of parameters that you suggest to consider (in addition to ex-ante defined KPIs)?*

QR18 *How important is the development of a remuneration for SI in order to spread out the technology tested in the demo?*

[(Not relevant) 1 - 2 - 3 - 4 - 5 (Very important)]

QR19 *How important is the development of a market for the Reactive Power (remunerated for RES) in order to spread out the technology tested in the demo?*

[(Not relevant) 1 -2 - 3 - 4 - 5 (Very important)]

QR20 *Which are the costs for installing a BESS unit to provide SI and AVR (taking also into account all externalities that a BESS could presents and possible alternative remunerations obtainable by supplying other ancillary services)?*

QR20b *Which could be the extra-cost of a WT able to supply SI and AVR as regards to a standard model?*

QR20c *How much overall capacity has to be installed to reach the minimum of the unit cost of the solution? Which are the elements that primarily impact on this aspect?*

QR24 *Do you foresee that TSO could force all RES power plant to provide SI at the power system? In the case SI will be mandatory, do you think that the function should be remunerated or not when it will be supplied? Does providing SI impact on plant cost of components aging?*

QR26 *Thanks to the revamping activity, can the solution have more chance to be installed? For existing plants, which are the expected criteria to be used for revamping WTs (e.g., lifetime of WTs) or the overall plant (e.g., installing a BESS)?*

QR27 *Do you think that replying the demo on several other plants (including other countries) could improve your reputation at a European/worldwide level (e.g., increase the ESG value, attract new investors…)?*

8.1.1.3 General statistics on completeness of the answers

In the following tables, the general statistics for each use case are reported (Table 8.2-Table 8.4).

The average completeness of the answers is high, and the participation in filling the questionnaires of the involved partners was total. The most uncompleted answers for all the use cases are the ones in the third sheet of the questionnaires, relevant to the CBA. Moreover, most of the answers related to the regulatory area of the scalability analysis of the UC2 are missing (75 %). However, by directly interviewing the partners, some lacks were covered by the authors of this report.

Table 8.2 General statistics of the unanswered questions – UC1

Type of questions/area	Total number of questions asked	% uncompleted answers	Number of added questions	% involved partner that filled the questionnaire
	UC1 Scalability			
Technical	114	0.9%	46	100%
Economical	40	0.0%	20	100%
Regulation	58	6.9%	8	100%
	UC1 Replicability			
Technical	72	8.6%	2	100%
Economical	30	0.0%	0	100%
Regulation	40	12.5%	0	100%
	UC1 CBA			
Cost benefit	110	38.2%	0	100%

Table 8.3 General statistics of the unanswered questions – UC2

Type of questions/area	Total number of questions asked	% uncompleted answers	Number of added questions	% involved partner that filled the questionnaire
	UC2 Scalability			
Technical	54	11.1%	38	100%
Economical	28	10.7%	20	100%
Regulation	28	75.0%	8	100%
	UC2 Replicability			
Technical	57	14.0%	28	100%
Economical	24	16.7%	15	100%
Regulation	26	15.4%	9	100%
	UC2 CBA			
Cost benefit	44	54.5%	0	100%

Table 8.4 General statistics of the unanswered questions – UC3

Type of questions/area	Total number of questions asked	% uncompleted answers	Number of added questions	% involved partner that filled the questionnaire
	UC3 Scalability			
Technical	36	3%	22	100%
Economical	14	0%	10	100%
Regulation	14	0%	4	100%
	UC3 Replicability			
Technical	14	0%	0	100%
Economical	6	0%	0	100%
Regulation	8	0%	0	100%
	UC3 CBA			
Cost benefit	22	77%	0	100%

8.2 SRA assessment results

The results of every single evaluation are reported in what follows for each use case. For the analysed functionality/solution, the assigned scores to each dimension (with comments), the radar plot of the result, the weighted scores obtained for each dimension, and the final indicators are reported.

8.2.1 UC 1 scalability results

8.2.1.1 DTR scalability

The scores assigned to the scalability dimensions of the weather-based DTR and the sensor-based DTR are in the following Table 8.5 and Table 8.6, respectively. In Figure 8.1, the radar plot of the obtained scores of the two technical solutions is shown. Table 8.7 reports the weighted scores and Table 8.8 the indicators that evaluate the scalability of the DTR applications.

Table 8.5 Scalability of weather-based DTR

Area	Key factor/Subareas	Score	Weather-Based DTR
Technical	Modularity	4	The solution is a program implemented in C language that runs in a multi-core processor. Thus, it is perfectly modular. It is scalable to how many lines (overhead, with nude conductors) one wants to monitor with the WB-DTR, as long as the input data, both structural and weather forecasting, are provided. The software will process as many lines as the number of processor cores at a time – the increase of the number of cores can be helpful if the observed area grows.
	Technology evolution	4	The actual TRL (7) ensures the scalability of the solution. Improvements in parallel computing or in HW resources (speed of the core processors) may improve the performance of the WB-DTR.
	Interface design	3	Since the WB-DTR algorithm interacts with PREVEL and Z-EMS, their data exchange and control are centralised, and the automation may fail.
	Software tools integration	4	The WB-DTR algorithm does not have to change with the growth of the number of the observed lines. The computational time for each line is very short (about 10 s), and different lines are processed in parallel by different cores of the processor. If the number of the observed lines increases, one core has to process one line after another, but the complete run unlikely can take more than the 15 min necessary to have a new set of input.
	Compatibility analysis	4	The WB-DTR solution is compatible with any overhead line constituted by nude conductors.
Economics	Economies of scale	5	The cost of the solution increases with the cost for providing the input of weather forecasting. But the cost of such service can be even reduced if the third party that provides the service makes offers in the case of large areas.

	Profitability	**5**	The profitability of the solution directly arises from benefits in the short and long term: the reduced costs for solving the contingencies (dispatching costs and the reduction of the wind generation curtailment costs); the deferral of the investments for new lines or for upgrading the existing ones. The costs to be sustained are not relevant to new software development but only to the time useful to implement the structural input data for new lines (2-3 hours per line) and the variable costs of the weather forecast. The viability may increase if the choice of the observed lines gives priority to those where the static thermal limit is often overcome.
Acceptance	**Regulatory issues**	**4**	The Italian Regulator approved output-based incentivizing mechanisms to be applied also to investments characterized by a low investment intensity, such as in the case of DTR. In order to promote investments in innovative solutions such as DTR, the Regulator extended the maximum admissible incentive to the maximum between the investment capital cost and a 10 million Euros cap, for each grid section or subsection. This possibility should be better investigated by the TSO.
	Consent	**4**	The involvement of the social partners may favour the deployment of the DTR solution. With this perspective, it should be emphasised/stressed that the DTR can defer building a new line (with an immediate benefit for the territory) and reduce the generation curtailment of the wind power plants (with an advantage for the producers but also with an enhancement of the RES integration).

Table 8.6 Scalability of sensor-based DTR

Area	Key factor/Subareas	Score	Sensor-Based DTR
Technical	**Modularity**	4	The solution is modular. It is scalable to how many lines one wants to monitor. It is necessary to increase the number of sensor nodes, whose mutual distance should guarantee the radio communication, and consider one master node per primary substation. A maximum of 100 sensors per line can be managed, but this number is even too big for realistic cases. The MICCA sensor may be used in a limited number of lines.
	Technology evolution	3	The actual TRL (7) ensures the scalability of the solution. However, the communication between sensors may become a critical issue in scalability. If the line extension covers a remote area, it is difficult to reach all the sensors of the cooperative group. The advances in ICT (e.g., the diffusion of 5G) can improve this issue. Still, the most advanced communication infrastructure will probably not be improved in the short or medium term in remote zones.
	Interface design	3	The data exchange between the cooperative network of sensors is by radio-based communication. Such architecture allows a dense spatial sampling without requiring the deployment of a Wide Area Network (e.g., GSM). However, since the master node interacts with the sensor node network and with the databases, their data exchange and control are centralised in the master node, and the automation may fail.
	Software tools integration	3	The master node theoretically does not have any limitation if the number of controlled lines grows (the number of feeders supplied by a given primary substation is limited, but the extension of these lines can be significant). Since the computational time for each line is short and it is not influenced by the number of sensors (less than 1 min for each line), the real limitation is in the communication latency between sensor nodes and master node (it increases with the number of sensor nodes, e.g., 10 nodes 1 min).
	Compatibility analysis	4	The SB-DTR solution is compatible with any other tools because it uses standard protocols of communication.
Economics	**Economies of scale**	4	The cost of the solution increases with the number of installed sensor nodes, but it is possible an economy of scale. The installation of many sensors makes sense only for limited zones, for instance, in the spans where there are the most critical conditions, or the orography is complex. Since the cost of the MICCA sensors is higher, its scalability is limited.
	Profitability	4	The cost of the SB-DTR solution is smaller than other commercial solutions. For instance, it is not necessary the deployment of a Wide Area Network (e.g., GSM), and the sensor nodes are quite cheap. The thermal model is the real added value of the solution because it accurately estimates the DTR by properly processing the input data.
Acceptance	**Regulatory issues**	4	The network of sensors communicates via radio. It is necessary to make the solution compliant with the rules on the award of radio frequencies (e.g., in Italy

			about 100€/y paid to the Ministry of economic development). Still, it is very improbable that the award of the needed radio frequencies is not granted.
	Consent	4	The involvement of the social partners may favour the deployment of the DTR solution. With this perspective, it should be emphasised/stressed that the DTR can defer building a new line (with an immediate benefit for the territory) and reduce the generation curtailment of the wind power plants (with an advantage for the producers but also with an enhancement of the RES integration).

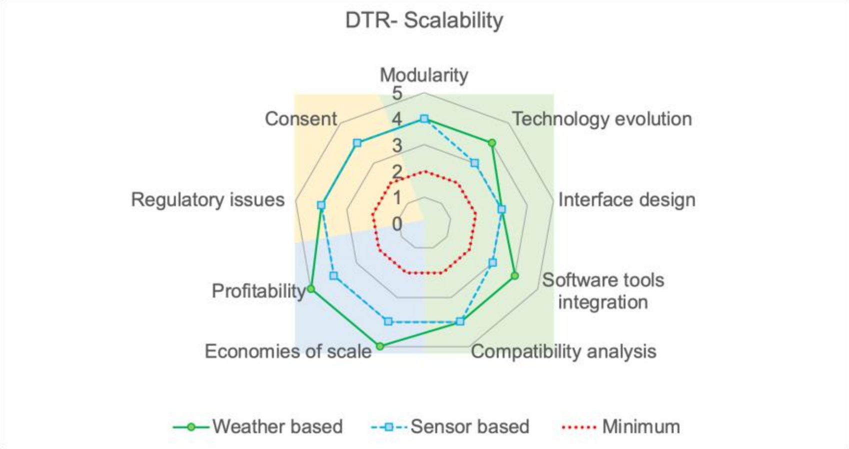


Figure 8.1 Radar plot of DTR scalability results

Table 8.7 DTR scalability weighted scores

		DTR- Weighted scores	
Area	**Key factor/Subareas**	Weather based	Sensor based
Technical	**Modularity**	4	4
	Technology evolution	2.4	1.8
	Interface design	2.4	2.4
	Software tools integration	3.6	2.7
	Compatibility analysis	2.8	2.8
Economics	**Economies of scale**	4.5	3.6
	Profitability	3.5	2.8
Acceptance	**Regulatory issues**	2.4	2.4
	Consent	2	2

Table 8.8 DTR scalability indicators

	DTR	
Scalability Indicator	Weather based	Sensor based
Technical	76.0%	68.5%
Economics	100.0%	80.0%
Acceptance	80.0%	80.0%
TOTAL	**82.4%**	**73.1%**

8.2.1.2 **Forecasting software -** PREVEL scalability

The scores assigned to the scalability dimensions of the PREVEL tool are in the following Table 8.9. In Figure 8.2 the radar plot of the obtained scores is shown. Table 8.10 reports the weighted scores and Table 8.11 the indicators that evaluate the scalability of the PREVEL tool.

Table 8.9 Scalability of PREVEL tool

Area	**Key factor/Subareas**	**Score**	**PREVEL**
Technical	**Modularity**	3	Since the SW exploits parallel computing, the solution is perfectly modular. It is scalable as long as the input data are provided, and the HW (number of cores of the processor and memory capacity) guarantees the required speed. The limitations are due: (i) to the number of cores for parallel computing and the capacity of RAM available to the virtual machine (VM) that should be increased with the number of forecasting points; (ii) the necessity of updating the data stored in the database when new loads (to be forecasted) become active (even

			during the demo it was often necessary such an update of the DB); (iii) the use of a VM instead an actual physical computer (communication problems arise).
	Technology evolution	4	The solution at the end of the demo phase reached the TLR 7.
	Interface design	2	The PREVEL and PrevDTR run continuously. Every 20 seconds they perform some checks to identify what they have to do (acquire data, aggregate data, store data in the database, activate the short-term forecast, activate the very short-term forecast, store data in the archive, transfer output files, and so on). Each operation is tracked in a log file and in the database, so that the status of the processes can be visualised via a web interface. In this way, it is possible to recognise missing input data or problems in real-time forecasts. The most critical issue is in the interaction of the databases. Two different databases were used to solve such a problem, one for daily calculations and another, with monthly tables, updated at 00 o'clock with the previous day's data. A check of the system status by a human operator is necessary every now and then for avoiding uncontrolled stops (e.g., for corrupt input data).
	Software tools integration	2	There are some master tables with static information (i.e., the geolocation of the observed primary substations), which must be updated when new points are added. When the number of observed points changes, it is necessary to define how many processors are dedicated to the different processes. The SW evaluates the forecasts accordingly. Furthermore, the problem is that the prediction methods require as long a training set as possible, so for newly introduced loads, it is not possible to have the predictions immediately, and persistence is adopted until a sufficiently long training set is available (i.e., six months for the short-term forecasting and three months for the very short forecasting). The SW is modular, but the modules depend on the local architecture (where and what are the input and the output) made by LISCAL (a software of the TSO that subdivides the network into subnets).
	Compatibility analysis	3	The SW can be applied to any size of the observed region, provided the new loads are uploaded in the input database, and the weather forecasts are extended to the new region. The greater the number of forecasting points, the greater the number of cores that should run simultaneously to obtain results with the required speed, the greater the needed capacity for storing data.
Economics	**Economies of scale**	5	The cost of the solution increases with the (possible) cost for providing the input of weather forecasting (one time a day). This can be even reduced if the third party that provides the service makes offers in the case of large areas. Furthermore, as stated before, the greater the number of observed points, the greater the number of cores that have to run parallelly and the memory capacity, assuring the requested speed. For instance, the implemented HW was sufficient to predict 1400 points in 90 seconds.
	Profitability	5	The costs to be sustained are not relevant to new software development but only to the time useful to update the database for new loads and the variable costs of the weather forecast. The viability may increase with the profit achievable with the exploitation of the flexibility services.
Acceptance	**Regulatory issues**	5	The European Regulators are taking important actions for promoting flexibility even at the distribution system level and giving a new role to the DSOs in coordinating the distributed energy resources connected to their networks. Such actions must necessarily include an improvement of the distribution system observability. Also, the Italian regulator is deeply involved in this promotion activity. With an improvement of observability, the PREVEL solution can obtain better performance. Thus, no regulatory barriers are envisaged.
	Consent	3	There is a generalised scepticism in the use of forecasts because they are not measures. But without any forecasting, one can use the persistence approach that is effective only for the next half hour. For exploiting flexibility is crucial to know in advance the electrical behaviour of customers and production plants, and 30 minutes are not enough. With the opening of markets of flexibility services to new potential participants, the necessity of forecasting will become clear to everybody and probably any scepticism will be deleted.

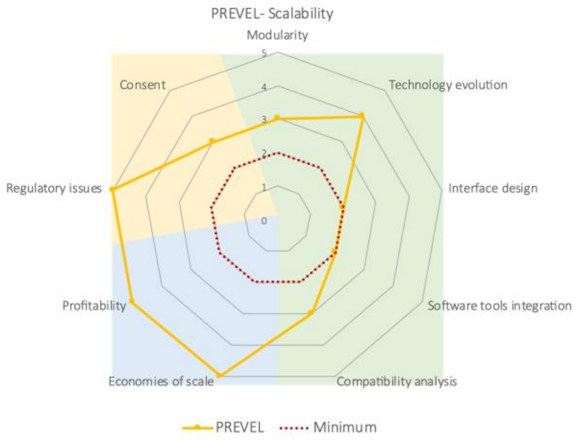


Figure 8.2 Radar plot of PREVEL scalability results

Table 8.10 PREVEL scalability weighted scores

Area	Key factor/Subareas	PREVEL
Technical	Modularity	3
	Technology evolution	2.4
	Interface design	1.6
	Software tools integration	1.8
	Compatibility analysis	2.1
Economics	Economies of scale	4.5
	Profitability	3.5
Acceptance	Regulatory issues	3
	Consent	1.5

Table 8.11 PREVEL scalability indicators

Scalability Indicator	PREVEL
Technical	54.5%
Economics	100.0%
Acceptance	81.8%
TOTAL	**74.6%**

8.2.1.3 Z-EMS scalability

The commented scores assigned to the scalability dimensions of the Z-EMS are reported in the following Table 8.12. In Figure 8.3 the radar plot of the obtained scores are shown. Table 8.13 reports the weighted scores and Table 8.14 the indicators that evaluate the scalability of the Z-EMS.

Table 8.12 Scalability of Z-EMS

Area	Key factor/Subareas	Score	Z-EMS
Technical	Modularity	3	*Pros*: the size of the network is not prescribed (i.e., the software can be executed on grids with different numbers of nodes and lines); then, the Z-EMS software is flexible in considering a different set of DTR and controllable loads. *Cons*: the time required to solve the OPF, detect and mitigate the congestion in the grid (when this is the case) depends on the size of the network, the number of lines in which DTR is installed, and the number of controllable loads.
	Technology evolution	5	Since the Z-EMS is being tested and validated in a real operational environment, at the end of the project its TLR is 8. However, some rooms for improvement could be envisaged. The historical data of reactive power provided by the TSO will permit to determine the reactive power predictions. The predictions of the reactive power, for every node in the grid, make it possible to solve the ACOPF, with a significant improvement of the result accuracy. In addition, the prediction of the network configuration can improve the result accuracy.
	Interface design	4	The Z-EMS has a daemon process that runs continuously and controls that the prescribed set of inputs is produced correctly. It consists of 3 processes: the first one checks the quality of the input data and prepares the instance of the optimization model, the second solves the set of optimization models, and the

			third writes the outputs for visualization. If the set of quality checks is not passed, the routine exits detailing in the log the check not satisfied.
	Software tools integration	3	The calculation time is affected by the size of the grid, the number of DTR and the number of controllable loads. The actual performance is around 2 min 30 s with 1600 nodes, 4000 lines, 7 DTR installed, and 3 controllable loads.
	Compatibility analysis	3	The demonstration area is composed of a portion of the Italian transmission grid. In the current implementation, Z-EMS detects and mitigates congestions for different areas. Limitations can be represented by the HW (number of processor cores and RAM amount) and the availability of the input data to provide.
Economics	**Economies of scale**	3	The costs depend on the number of processor cores and RAM that are related to the grid size, the DTR number and the number of controllable loads.
	Profitability	3	To decide to what extent the project is economically viable, a business case has to be addressed by answering questions regarding the expected number of congestions per year, with the model accuracy and further calculations.
Acceptance	**Regulatory issues**	4	There are no regulations that may drive the uptake of the innovation, but there are no barriers to the adoption of the solution.
	Consent	4	The stakeholders are the TSO and the final users. The benefits of accepting the Z-EMS component are to reduce the number of grid congestions by using the DTR technology and/or controllable loads.

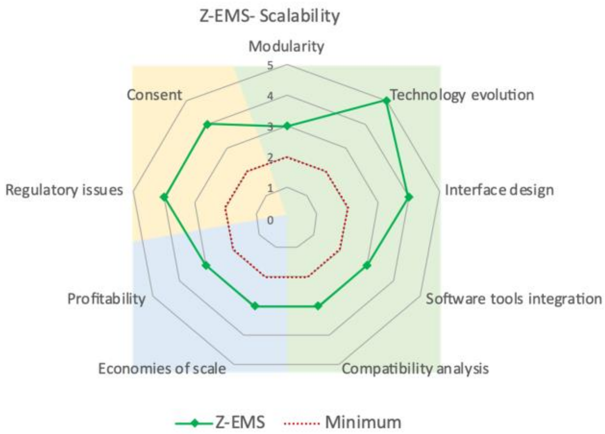


Figure 8.3 Radar plot of Z-EMS scalability results

Table 8.13 Z-EMS scalability weighted scores

Area	Key factor/Subareas	Z-EMS
Technical	**Modularity**	3
	Technology evolution	3
	Interface design	3.2
	Software tools integration	2.7
	Compatibility analysis	2.1
Economics	**Economies of scale**	2.7
	Profitability	2.1
Acceptance	**Regulatory issues**	2.4
	Consent	2

Table 8.14 Z-EMS scalability indicators

Scalability Indicator	Z-EMS
Technical	70.0%
Economics	60.0%
Acceptance	80.0%
TOTAL	**69.3%**

8.2.1.4 Dashboard scalability

The commented scores assigned to the scalability dimensions of the dashboard are reported in the following Table 8.15. In Figure 8.4 the radar plot of the obtained scores is shown. Table 8.16 reports the weighted scores and Table 8.17 the indicators that evaluate the scalability of the dashboard.

Table 8.15 Scalability of the dashboard

Area	Key factor/Subareas	Score	Dashboard
Technical	**Modularity**	4	It could be possible to add other components (sources of data) such as shared folders since the interaction is based on standard protocols. Even if there are no limits that affect the proper functioning of the solution, it may be necessary to extend the Dashboard functionalities.
	Technology evolution	2	It could be necessary to reduce the response time of the Dashboard. In case the number of data sources increases, and the file size massively changes, the hardware resources must be upgraded.
	Interface design	4	The Dashboard interacts only with the HoD handling the control.
	Software tools integration	3	The Dashboard may affect the performance of the Z-EMS: if the Dashboard does not update the file of the aggregator offers properly, the Z-EMS could reach an error status and eventually stop.
	Compatibility analysis	4	The overall demo solution, including the Dashboard, is installed, and configured for the TSO (Terna) intranet where the proper ICT infrastructure was set up. At the moment, no limits are envisioned.
Economics	**Economies of scale**	3	The dashboard does not require a high computational burden. However, it may be necessary to improve the disk space if the size of the files increases, with the related costs.
	Profitability	4	The Dashboard is available for the TSO and represents a business opportunity for both the TSO and the developing company (ENGINEERING).
Acceptance	**Regulatory issues**	0	Not applicable
	Consent	4	The Dashboard was developed according to the WP5 needs. Looking at the TSO (Terna) as the main stakeholder, the Dashboard reflects the TSO needs and satisfies the demo requirements.

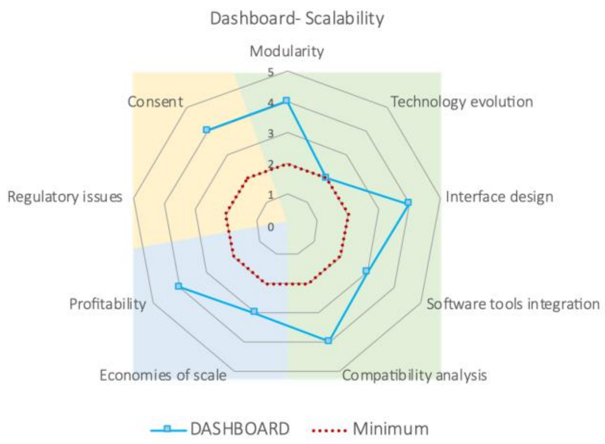


Figure 8.4 Radar plot of the dashboard scalability results

Table 8.16 Dashboard scalability weighted scores

Area	Key factor/Subareas	Dashboard
Technical	Modularity	4
	Technology evolution	1.2
	Interface design	3.2
	Software tools integration	2.7
	Compatibility analysis	2.8
Economics	Economies of scale	2.7
	Profitability	2.8
Acceptance	Regulatory issues	---
	Consent	2

Table 8.17 Dashboard scalability indicators

Scalability Indicator	Dashboard
Technical	69.5%
Economics	68.8%
Acceptance	80.0%
TOTAL	**70.2%**

8.2.1.5 Hand Of Data scalability

The scores assigned to the scalability dimensions of the Hand Of Data are in the following Table 8.18. In Figure 8.5 the radar plot of the obtained scores is shown. Table 8.19 reports the weighted scores and Table 8.20 the indicators that evaluate the scalability of the Hand Of Data.

Table 8.18 Scalability of the Hand Of Data

Area	Key factor/Subareas	Score	Hand Of Data
Technical	Modularity	4	It could be possible to add other components (sources of data) such as databases or shared folders because the interaction with this kind of system is based on standard protocols. Even if there are no limits that affect the proper functioning of the solution, it may be necessary to extend the HoD functionalities.
	Technology evolution	3	Any improvement in the orchestration process may reduce the data provision time if the number of data sources increases. In this case it may be necessary to also increase the hardware resources. The HoD was developed from scratch. The TRL at the end of the project is TRL 7 since the HoD is running on the operational environment hosted by Terna.
	Interface design	3	The HoD design satisfies the demo requirement and minimizes the calculation time for data provision. HoD is strictly connected to Z-EMS. In fact, if the HoD does not transfer the files correctly to the Z-EMS, the Z-EMS cannot run.
	Software tools integration	4	The HoD, responsible for the data orchestration process, implements the control that is arranged through an effective scheduling process that manages the timing of the overall demo execution. This process is implemented considering the data protection and data integrity. The implemented control achieves the optimal demo execution.
	Compatibility analysis	4	The overall demo solution, including the HoD, is installed and configured for the TSO (Terna) intranet where the proper ICT infrastructure was set up. At the moment, no limits are envisioned.
Economics	Economies of scale	3	One cost can be associated with the improvement of the hardware solution (CPU, RAM, and disk space); it may be a cost related to the extension of HoD features if required.
	Profitability	4	The HoD is available for the TSO and represents a business opportunity for both the TSO and the developing company (ENGINEERING). Scalability in terms of density (same area, more units) or size (larger area) has no barriers.
Acceptance	Regulatory issues	0	Not applicable
	Consent	4	HoD was developed according to the WP5 needs. Looking at TSO (Terna) as the main stakeholder, the HoD reflects the TSO needs and satisfies the demo requirements.

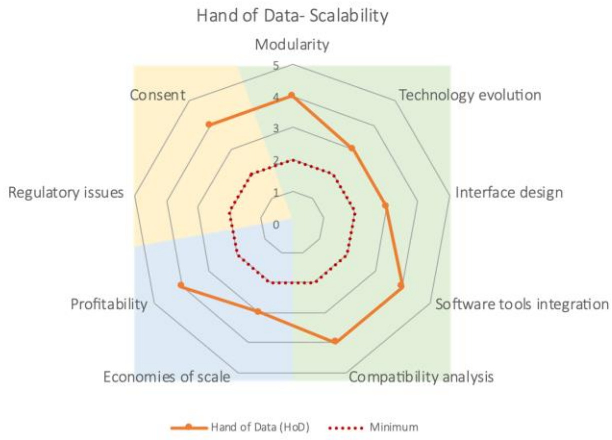


Figure 8.5 Radar plot of the Hand Of Data scalability results

Table 8.19 Hand Of Data scalability weighted scores

Area	Key factor/Subareas	Hand Of Data
Technical	Modularity	4
	Technology evolution	1.8
	Interface design	2.4
	Software tools integration	3.6
	Compatibility analysis	2.8
Economics	Economies of scale	2.7
	Profitability	2.8
Acceptance	Regulatory issues	0
	Consent	2

Table 8.20 Hand Of Data scalability indicators

Scalability Indicator	Hand Of Data
Technical	73.0%
Economics	68.8%
Acceptance	80.0%
TOTAL	**72.5%**

8.2.1.6 DSR for congestion resolution scalability

The scores assigned to the scalability dimensions of the DSR for congestion resolution are reported in the following Table 8.21. In Figure 8.6 the radar plot of the obtained scores is shown. Table 8.22 reports the weighted scores and Table 8.23 the indicators that evaluate the scalability of the DSR for congestion resolution.

Table 8.21 Scalability of the DSR for congestion resolution

Area	Key factor/Subareas	Score	DSR for congestion resolution
Technical	Modularity	4	The demo addresses aggregator and process sides. HW on site is modular. The aggregation platform is easily scalable. The modulating power depends on the characteristics of local loads; hence, it is relevant to predict the baseline of the plant requirements.
	Technology evolution	3	The actual TRL ensures the scalability of the solution with reference to the aggregator side: it could be expected that more sophisticated logics and tools have to be developed in the short/medium term. The controllable loads for the flexibility services should be automatised in terms of monitoring, communication, and actuator functionalities.
	Interface design	3	Opportune priority strategies must be arranged between aggregator and plants. Priority strategies are affected by load and plant sizes. The limited size of the demo did not make it possible to test priority approaches.

	Software tools integration	4	Generally, there is no need to improve software. Very high numbers of flexible resources could lead to an increase of calculation time in order to solve the optimization problem.
	Compatibility analysis	4	No limits have been highlighted in the current infrastructure. It is already a production environment used for Terna pilot projects on flexibility.
Economics	**Economies of scale**	4	From the point of view of the aggregator, if the size of the flexibility resource increases, no extra costs are foreseen. If complexity or acquired data increase, the cost of the aggregation platform and the data storage it is expected to increase marginally.
	Profitability	3	With regards of the identified resources, the project was not economically viable. This was due to the flexibility resources enabled which were too small to repay fixed (infrastructural) and variable costs. Profitability evaluation of the solution requires to define the context of remuneration schemes.
Acceptance	**Regulatory issues**	4	There are not regulatory barriers. The evolution of regulations could favour cost-benefit ratio (i.e., remunerations).
	Consent	4	Incentives or specific economical treatment can be opportune in order to obtain stakeholder acceptance. Scale-up of the new functionalities can improve the company's position (social, environment...).

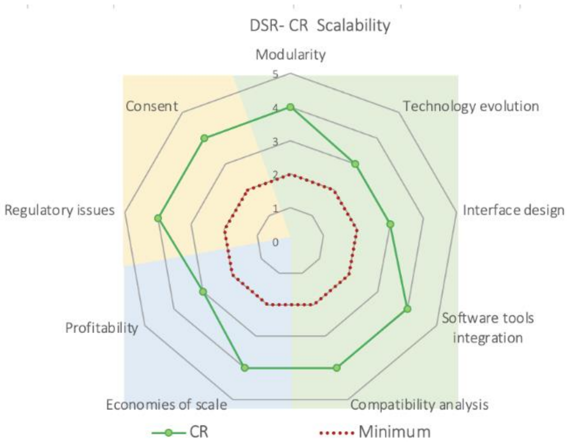


Figure 8.6 Radar plot of the DSR for CR scalability results

Table 8.22 DSR for CR scalability weighted scores

Area	Key factor/Subareas	DSR for CR
Technical	**Modularity**	4.0
	Technology evolution	1.8
	Interface design	2.4
	Software tools integration	3.6
	Compatibility analysis	2.8
Economics	**Economies of scale**	3.6
	Profitability	2.1
Acceptance	**Regulatory issues**	2.4
	Consent	2.0

Table 8.23 DSR for CR scalability indicators

Scalability Indicator	DSR for CR
Technical	73.0%
Economics	71.3%
Acceptance	80.0%
TOTAL	**73.7%**

8.2.2 UC 1 replicability results

8.2.2.1 DTR replicability

Table 8.24 and Table 8.25 report the assigned scores to the replicability dimensions respectively of the weather-based DTR and the sensor-based DTR. Figure 8.7 shows the radar plot of the DTR replicability results obtained for the two solutions. Table 8.26 and Table 8.27 report the weighted scores and the assessed values of the replicability indicators for the two technical solutions.

Table 8.24 Replicability of weather-based DTR

Area	Key factor/Subareas	Score	Weather-Based DTR
Technical	Standardization	4	The thermal model of the conductors is compliant with a CIGRE standard model. The solution is perfectly compatible and interoperable with any grid codes since its output can be used by customizing the decision-making process. For instance, the TSO can decide of moving the limit of line ampacity from the static to the dynamic one considered reasonable (i.e., the one allowable for a certain time duration).
	Interoperability	4	Since the WB-DTR solution is a software tool constituted by an executable program, it is ideally plug & play (or better cut & paste) in any computer with MS Windows as the operative system (WIN10). It needs only a code compiling process (2 minutes long), for running it in different operative systems. The software runs as long as the input data are provided. For replicating the WB-DTR solution to cables, the model of the heat transfer between cables and earth should be developed by considering that the thermal inertia of the cables is slower than the one of the nude conductors and that the over-temperature derived by current increases negatively impact the insulation materials of the cables.
	Network configuration	4	The network configuration, radial or meshed, does not influence the WB-DTR. The solution can be applied to any overhead line constituted by nude conductors elsewhere provided that the weather forecast input is available for the area on which are located the examined lines. The voltage level does not influence the WB-DTR performance; thus, theoretically, the WB-DTR can be applied at lines of any voltage level. However, the opportunity to use the WB-DTR in MV lines should be accurately evaluated.
Economics	Macro-economic factors	5	DTR reduces the costs of generation redispatching, since it identifies which conditions of apparent grid congestions do not imply a real conductor overheating or overelongation. This is particularly noticeable when line overloading is due to strong wind production, because DTR properly captures the point that the higher wind speed, the higher conductor cooling; this is why DTR contributes to the integration of wind farms on the current grids. The profitability of the solution could be even more profitable than in Italy. In particular, it is more profitable in countries where the dispatching charges are high (i.e., where thermoelectric units are used for solving congestions), or the generation curtailment is frequent (greater penetration level of wind).
	Market and business model	4	The solution is economically viable, and no barriers are envisaged
Regulatory	Regulatory issues	4	The WB-DTR solution is feasible and viable regardless of the specific national or regional regulation and it is possible to extend the solution to all the overhead lines of the world.
	Acceptance	4	The acceptance of the solution is self-evident because the use of the DTR solution may contribute to reducing the final user energy bill (by reducing the dispatching charges), may help to integrate more RES in the network (by decreasing the resort to the wind generation curtailment) and can defer the investments in new lines (by identifying false congestions that make the current assets to be substituted).

Table 8.25 Replicability of sensor-based DTR

Area	Key factor/Subareas	Score	Sensor-Based DTR
Technical	Standardization	4	The thermal model of the conductors is compliant with the IEEE standard thermal model. The communications are all via standardized solutions (via radio and via TCP/IP protocol). The solution is perfectly compatible and interoperable with any grid codes since its output can be used by customizing the decision-making

			process. For instance, the TSO can decide of moving the limit of line ampacity from the static to the dynamic one considered reasonable (i.e., the one allowable for a certain time duration).
	Interoperability	4	The solution is "plug & play". The only limitation is due to the structural input that can be provided in a given format. From a technical point of view, the current version of the SB-DTR can be applied to any environment. The software runs as long as the input data are provided.
	Network configuration	4	The network configuration, radial or meshed, does not influence the SB-DTR tool. The solution can be applied to any voltage level network, even if DTR is less interesting at the distribution level. The main limitation is that since the sensors of the cooperative network communicate via radio, it must be assured that this communication would be successful (the number of sensors must increase in areas with complex orography). It is suggested to guarantee a reliable network of sensors (at least compliant with the N-1 criterion).
Economics	**Macro-economic factors**	5	The profitability of the solution could be even more profitable than in Italy. In particular, it is more profitable in countries where the dispatching charges are high (i.e., where thermoelectric units are used for solving congestions), or the generation curtailment is frequent.
	Market and business model	3	The solution is economically viable. The only warning is relevant to the rules of the award of the radio frequencies in the other considered countries.
Regulatory	**Regulatory issues**	3	The regulatory framework does not influence the size and the scope of the solution, and the only improbable barriers are related to the rules for the award of radio frequencies.
	Acceptance	4	The acceptance of the solution is self-evident because the use of the DTR solution may contribute to reducing the final user energy bill (by reducing the dispatching charges), may help to integrate more RES in the network (by decreasing the resort to the wind generation curtailment) and can defer the investments in new lines (by identifying false congestions that make the current assets to be substituted).

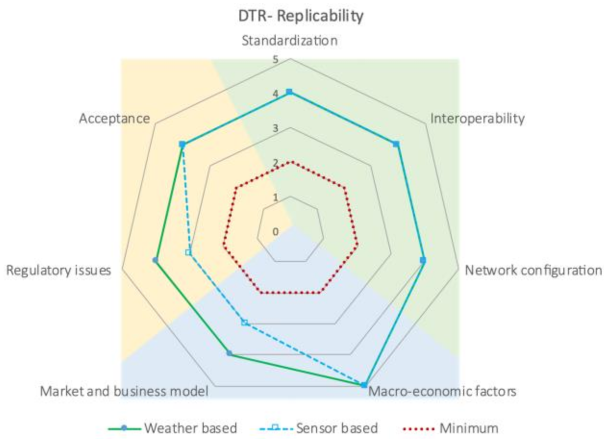


Figure 8.7 Radar plot of DTR replicability results

Table 8.26 DTR replicability weighted scores

		DTR	
Area	**Key factor/Subareas**	Weather based	Sensor based
Technical	**Standardization**	4	4
	Interoperability	3.6	3.6
	Network configuration	3.2	3.2
Economics	**Macro-economic factors**	3.75	3.75
	Market and business model	3.6	2.7
Regulatory	**Regulatory issues**	3.6	2.7
	Acceptance	2.4	2.4

Table 8.27 DTR replicability indicators

	DTR	
Replicability Indicator	Weather based	Sensor based
Technical	80.0%	80.0%
Economics	89.1%	78.2%
Regulatory	80.0%	68.0%
TOTAL	82.6%	76.4%

8.2.2.2 **Forecasting software -** PREVEL replicability

Table 8.28 reports the assigned scores to the replicability dimensions of the PREVEL tool. Figure 8.8 shows the radar plot of the PREVEL replicability results. In Table 8.29 and Table 8.30 the weighted scores and the assessed values of the replicability indicators of the PREVEL tool are reported.

Table 8.28 Replicability of PREVEL tool

Area	**Key factor/Subareas**	**Score**	**PREVEL**
Technical	**Standardization**	4	The SW has been written using opensource products (perl5, R), and they can be understood and modified by anyone. The mathematical formulation considered the random forest and the analog enseble algorithms that have been widely used in Literature for load forecasting in the last ten years. They are not standardized methods but well-consolidated approaches. Maybe, the compliance with grid codes has to be checked in the technical solutions that use the results of PREVEL.
	Interoperability	5	The SW code is written for a linux server, and is independent of the distribution adopted, but perl5 and R are also available for windows without significant code changes.
	Network configuration	4	The network configuration does not influence the performance of PREVEL. For instance, the solution can be applied to the secondary substations for forecasting the power exchange at the MV/LV interfaces.
Economics	**Macro-economic factors**	4	The need for real-time generation/load forecast is a general requirement, independent by the country. Thus, no barriers are detected
	Market and business model	3	The SW is ideally replicable if the input data are in the same format of the case studied. The code should be revised if the available input data will be different from the ones passed to the current solution (e.g., the subdivision of the network into subnets, the real-time and historical data, etc.).
Regulatory	**Regulatory issues**	5	In countries where the observability of the distribution network is included/mandatory in any regulatory framework, PREVEL can be even advantaged by this condition.
	Acceptance	4	Since PREVEL is an open-source SW, the solution can be easily accepted by the TSOs of other countries.

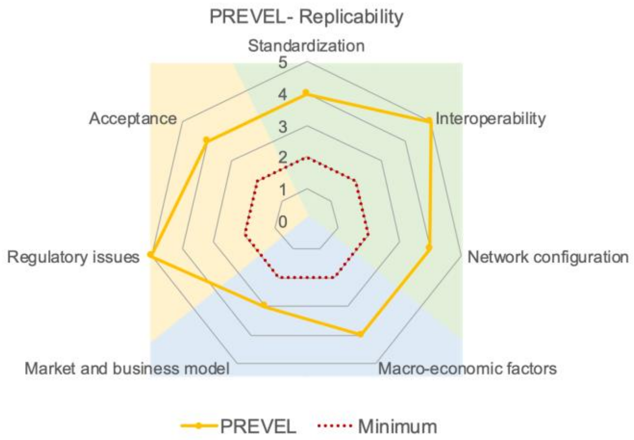


Figure 8.8 Radar plot of PREVEL replicability results

Table 8.29 PREVEL replicability weighted scores

Area	Key factor/Subareas	PREVEL
Technical	**Standardization**	4
	Interoperability	4.5
	Network configuration	3.2
Economics	**Macro-economic factors**	3
	Market and business model	2.7
Regulatory	**Regulatory issues**	4.5
	Acceptance	2.4

Table 8.30 PREVEL replicability indicators

Replicability Indicator	PREVEL
Technical	86.7%
Economics	69.1%
Regulatory	92.0%
TOTAL	**83.1%**

8.2.2.3 Z-EMS replicability

Table 8.31 reports the assigned scores to the replicability dimensions of the Z-EMS. Figure 8.9 shows the radar plot of the Z-EMS replicability results. Table 8.32 and Table 8.33 report the weighted scores and the assessed values of the replicability indicators of the Z-EMS.

Table 8.31 Replicability of Z-EMS

Area	Key factor/Subareas	Score	Z-EMS
Technical	**Standardization**	4	The software is written using open-source code (Python). The optimization model is solved using CPLEX. In order to use the Z-EMS component, CPLEX should be installed. Hence, no barriers due to the use of non-replicable codes have been detected.
	Interoperability	3	There are some master tables with static information (static limits of lines), which can be updated when needed. The function that pre-processes the input data organized by Hand of Data depends on the format and structure of the input files. This function should be adapted to the new set of input files. The algorithm that solves the optimization problems is a plug and play solution, able to adapt its working and interaction to a different setting. The software is written for a Windows server and is independent of the version considered. Python and CPLEX are also available for Linux without having to make major changes in the codes.
	Network configuration	3	The software may be applied, if the same file format is used. Hence, a preliminary check must be carried out. The voltage level has no impact on the software solution.
Economics	**Macro-economic factors**	5	The profitability of the Z-EMS strictly depends on the benefits obtainable with its use in managing and solving congestions. In particular, since identifies the congestions and optimises the cost of the redispatching, it is more profitable in countries on which dispatching charges are high (i.e., where thermoelectric units used for solving congestions), or the generation curtailment is frequent.
	Market and business model	4	The software was written according to the specifications of the received input data. If the same information is available, a new function that pre-processes the inputs should be implemented, while the component that solves the optimization problem will be the same.
Regulatory	**Regulatory issues**	0	Not applicable.
	Acceptance	5	The acceptance of the solution is self-evident because the use of the Z-EMS solution may contribute to reduce network congestions, may help to integrate more RES in the network, and can defer the investments in new lines (by exploiting the DTR output for identifying false congestions that require the current assets to be substituted).

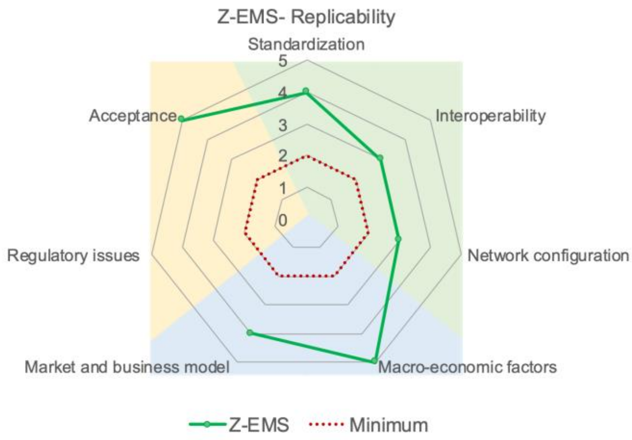


Figure 8.9 Radar plot of Z-EMS replicability results

Table 8.32 Z-EMS replicability weighted scores

Area	Key factor/Subareas	Z-EMS
Technical	Standardization	4
	Interoperability	2.7
	Network configuration	2.4
Economics	Macro-economic factors	3.75
	Market and business model	3.6
Regulatory	Regulatory issues	---
	Acceptance	3

Table 8.33 Z-EMS replicability indicators

Replicability Indicator	Z-EMS
Technical	67.4%
Economics	89.1%
Regulatory	100.0%
TOTAL	**78.6%**

8.2.2.4 Dashboard replicability

Table 8.34 reports the assigned scores to the replicability dimensions of the dashboard. Figure 8.10 shows the radar plot of the dashboard replicability results. In Table 8.35 and Table 8.36 the weighted scores and the assessed values of the replicability indicators of the dashboard are reported.

Table 8.34 Replicability of the dashboard

Area	Key factor/Subareas	Score	Dashboard
Technical	Standardization	4	The dashboard relies upon standard protocols. Hence, no barriers are detected.
	Interoperability	4	The technologies adopted in the dashboard can be easily deployed in different environments without additional investment.
	Network configuration	3	The technology may be applied, if the same file format is used. Hence, a preliminary check must be applied. The voltage level has no impact on the software solution.
Economics	Macro-economic factors	4	The macro-economic factors do not directly influence the success of the dashboard as a component. Moreover, it can be exported in other countries, independently of macro-economic factors.
	Market and business model	4	The solution is viable under different settings (e.g., other EU countries). No barriers have been detected.
Regulatory	Regulatory issues	0	Not applicable.

	Acceptance	4	There are no acceptance issues. The Dashboard can be exported to other countries in order to satisfy the TSO requirements.

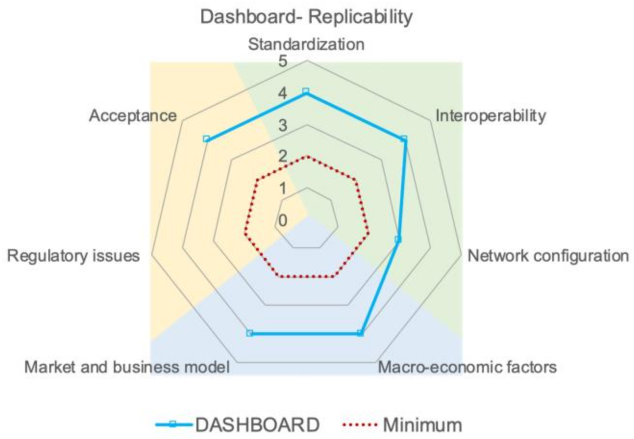


Figure 8.10 Radar plot of the dashboard replicability results

Table 8.35 Dashboard replicability weighted scores

Area	Key factor/Subareas	Dashboard
Technical	**Standardization**	4
	Interoperability	3.6
	Network configuration	2.4
Economics	**Macro-economic factors**	3
	Market and business model	3.6
Regulatory	**Regulatory issues**	---
	Acceptance	2.4

Table 8.36 Dashboard replicability indicators

Replicability Indicator	Dashboard
Technical	74.1%
Economics	80.0%
Regulatory	80.0%
TOTAL	**76.8%**

8.2.2.5 Hand Of Data replicability

Table 8.37 reports the assigned scores to the replicability dimensions of the Hand Of Data. Figure 8.11 shows the radar plot of the Hand of Data replicability results. In Table 8.38 and Table 8.39 the weighted scores and the assessed values of the replicability indicators of the Hand Of Data are reported.

Table 8.37 Replicability of the Hand Of Data

Area	Key factor/Subareas	Score	Hand of Data
Technical	**Standardization**	3	The HoD was developed according to the requirements provided by the Italian TSO (TERNA). The compliance with the other grid codes has to be checked. Standard protocols have been used in the communication mechanism between the HoD and the different data sources.
	Interoperability	3	The technology adopted for the delivery of HoD allows an easy deployment in different environments. However, the HoD needs a configuration setting in order to be replicated in other contexts. Moreover, some feature extensions could be possible in case of new specific requirements.
	Network configuration	0	The network characteristics have no role in the HoD operation.
Economics	**Macro-economic factors**	4	The macro-economic factors do not directly influence the success of the HoD as a component. Moreover, it can be exported in other countries, independently of macro-economic factors.

	Market and business model	4	The solution is viable under different settings (e.g., other EU countries). No barriers have been detected.
Regulatory	**Regulatory issues**	0	Not applicable.
	Acceptance	4	There are no acceptance issues. The HoD can be exported to other countries in order to satisfy the TSO requirements.

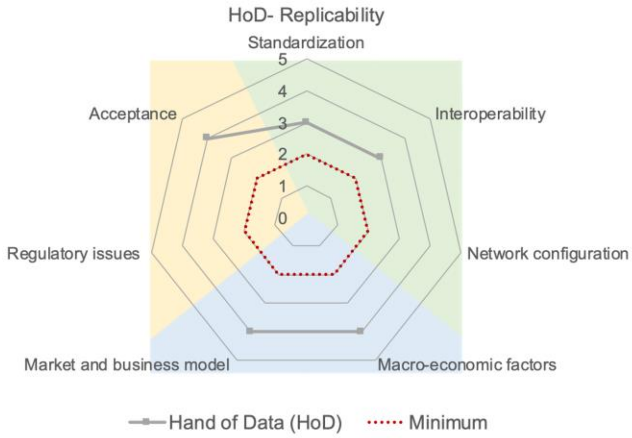


Figure 8.11 Radar plot of the Hand Of Data replicability results

Table 8.38 Hand Of Data replicability weighted scores

Area	Key factor/Subareas	Hand of Data
Technical	**Standardization**	3
	Interoperability	2.7
	Network configuration	---
Economics	**Macro-economic factors**	3
	Market and business model	3.6
Regulatory	**Regulatory issues**	---
	Acceptance	2.4

Table 8.39 Hand Of Data replicability indicators

Replicability Indicator	Hand of Data
Technical	60.0%
Economics	80.0%
Regulatory	80.0%
TOTAL	**70.8%**

8.2.2.6 DSR for congestion resolution replicability

Table 8.40 reports the assigned scores to the replicability dimensions of the DSR for congestion resolution. Figure 8.12 shows the radar plot of the DSR for congestion resolution results. In Table 8.41 and Table 8.42 the weighted scores and the assessed values of the replicability indicators of the DSR for congestion resolution are reported.

Table 8.40 Replicability of the DSR for congestion resolution

Area	Key factor/Subareas	Score	DSR for congestion resolution
Technical	**Standardization**	3	The solution implemented can be replicable, but some barriers have been found. In particular, the communication standard protocol requires tests and verification to have cost-benefits. A standardised base load forecaster could help the replicability of the solution. Further analyses and verification are needed.
	Interoperability	3	The main barrier to replicability is related to the characteristics of the local resource flexibility. It depends on the customer and the

			flexibility resources identified. A local customization of the set-up is always required.
	Network configuration	4	The solution implemented is potentially applicable in other industrial contexts once a remote automatic control of the local resource has been implemented. Investments have to be verified, in particular, with reference to the level of impact on the site's consumption.
Economics	**Macro-economic factors**	3	The solution is potentially replicable, but further developed are necessary. The profitability of the solution depends on local territorial factor, specifically in terms of economic remuneration of the service.
	Market and business model	3	Although the solution is potentially replicable, further analyses are required to verify the economic viability related to the complexity of the different territorial and market scenarios.
Regulatory	**Regulatory issues**	3	The solution is potentially replicable but further developed are necessary in particular depending on the grid codes and regulations of the countries where this solution should be replicated. Response times and accuracy requirements in terms of set points satisfaction can be conditioned by national and regional regulation rules.
	Acceptance	3	The solution is potentially replicable but further developments are necessary to make the solution acceptable.

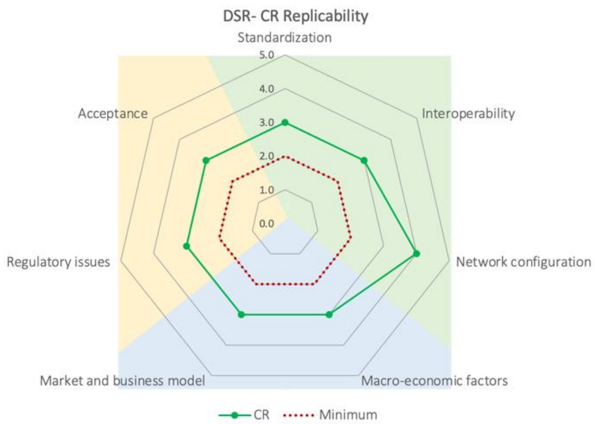


Figure 8.12 Radar plot of the DSR for CR replicability results

Table 8.41 DSR for CR replicability weighted scores

Area	Key factor/Subareas	DSR for CR
Technical	**Standardization**	3.0
	Interoperability	2.7
	Network configuration	3.2
Economics	**Macro-economic factors**	2.3
	Market and business model	2.7
Regulatory	**Regulatory issues**	2.7
	Acceptance	1.8

Table 8.42 DSR for CR replicability indicators

Replicability Indicator	DSR for CR
Technical	65.9%
Economics	60.0%
Regulatory	60.0%
TOTAL	**62.7%**

8.2.3 UC 2 scalability results

8.2.3.1 RES + BESS and DFIG for SI provision scalability

The scores assigned to the scalability dimensions of the synthetic inertia provision by RES + BESS and DFIG are in the following Table 8.43 and Table 8.44, respectively. In Figure 8.13 the radar plot of the obtained scores of the two technical solutions is shown. Table 8.45 reports the weighted scores and Table 8.46 the indicators that evaluate the scalability of the SI provision technical solutions.

Table 8.43 Scalability of RES + BESS for SI provision

Area	Key factor/Subareas	Score	RES+BESS for SI provision
Technical	Modularity	4	In this case, SI to support network stability is supplied only by the BESS, whereas WTs are not equipped to provide the service. BESS could be easily scaled up, depending on technical-economic analysis, by adding additional components (batteries/BMSs/inverters) connected in parallel downstream the plant POD. It should be noted that this solution assures the maximum flexibility in setting the SI contribution since main characteristics of the BESS response (e.g., maximum power contribution, gain, activation thresholds, etc.) are not directly related to the wind plant rated power, then they could be sized independently in accordance with grid requirements. Field tests demonstrated a contribution up to 800 kW (4.44% of the rated power), according to BESS capability constraints. Since the SI is provided by the BESS, the availability of the plant in supplying the service is independent from the primary source availability. An additional HW device called Synthetic Inertia Control Device (SICD) was developed by the partner to allow the BESS to provide SI. The SICD consists in a PLC. Its size, main specs and implemented functionalities do not depend by BESS size and type. Then, nothing has to be added on the SICD to scale-up the solution's size.
	Technology evolution	3	The present TRL ensures the scalability of the solution without significative barriers. To achieve the commercial stage of the developed equipment, industrialization and certification of the product will be required. Improvements of inverter performances (e.g., smart inverter with grid-forming functionalities, reduced response time, increased accuracy, and reliability) could help to increase size, effectiveness and competitivity of the solution in providing SI. An improvement in the measurement chain and in applied logics is required in order to correctly identify network events that require the provision of SI by the BESS.
	Interface design	4	SI is provided only by the BESS, then the solution does not require strong coordination with WTs. SICD is programmed to limit the SI contribution in the case the plant production is very high and providing SI could results in exceeding the maximum power injection agreed with the TSO in the connection contract. A similar logic is imposed to avoid excessive power absorption from the network in the case of over-frequency and absence of wind. Scaling-up the solution in terms of absolute value (i.e. increasing the maximum SI power contribution during frequency perturbations) can lead to install additional BESS units in parallel. In this case, it is highly recommended that only one measurement device evaluates the ROCOF for the entire BESS system and controls all the BESS units. This allows to avoid anomalous behaviours of single BESS units caused by inconsistent measurements independently performed by each BESS unit (e.g., due to unexpected delays or errors in the ROCOF measurement). In general, considering that BESS units are installed closely, this does not involve significant limitations in terms of required communication devices
	Software tools integration	4	The software installed in the SICD to control the BESS in providing SI is fully in-house developed. Software performances are not affected by the size of the plant, consequently they do not represent a barrier in scaling-up the solution. In fact, independently from the overall BESS size, the software measures frequency and ROCOF in a single network point close to BESS terminals. Then, it elaborates the SI contribution and sends the reference power to the inverters of operative BESS units. SI contribution is locally controlled according to a set of configuration parameters agreed with the TSO (e.g., SI gain, activation thresholds in terms of both frequency and ROCOF, hysteresis values, etc.)
	Compatibility analysis	3	At present, the SI contribution is limited by the maximum power injectable at the POD (parameter agreed with the TSO) in the case of under-frequency and high wind availability. Similarly, the SI contribution is constrained by the maximum power absorption at the POD in the case of over-frequency perturbation during

			wind absence. Considering the aging of BESS components, providing SI implies an increased stress due to rapid charge/discharge cycles imposed by the service, which falls in the range of power-intensive uses of storage devices. This additional stress is directly influenced by the set of configuration parameters and modalities to be agreed with the TSO, such as for example the SI gain and the activation thresholds (both in terms of frequency variation and ROCOF). Reducing activation thresholds involves a more frequent use of the device, even in the case of normal frequency perturbations. On the other side, increasing the activation thresholds limits the SI provision only to serious network events.
Economics	**Economies of scale**	3	The installation of a BESS in a wind farm is not a consolidated practice to date, then providing the SI by making use of the BESS requires that this device is already installed in the site. In this case, the cost to implement the solution is related only to the SICD. Since only one SICD is required independently from the size of the BESS, the relative cost of the SICD (i.e., cost per MW of the BESS) decreases as the size of the BESS increases. So, scaling-up the solution can be advantageous to reduce relative cost of the SICD (even if the SICD cost remains very limted in comparison with the entire BESS investment). It is necessary to consider that the optimal size of the BESS needs to be assessed by the plant owner taking into account both technical constraints (e.g., required SI contribution according to wind farm rated power) and economic issues, considering that convenience and competitiveness of the BESS are related to a set of ancillary services that it can provide to the main network and to the wind farm itself.
	Profitability	2	The solution profitability is clearly correlated with the BESS capital cost. It is difficult to evaluate the profitability of the scaled-up solution since no remuneration schemes for the provision of SI presently exist. It seems reasonable that in future the service will be remunerated if the plant will be able to provide SI according to defined criteria in terms of performance and availability.
Acceptance	**Regulatory issues**	2	SI is not presently regulated from both the technical and the economical point of view. The Italian grid code currently prescribes a fast frequency regulation, i.e. wind power plants connected to the HV main grid have to be able to supply a surplus of active power (0-10% of the plant rated power, standard value 6%) for a time interval (0-30 s, standard value 10 s) in the case of network under-frequency exceeding an activation threshold (range 49.5-50 Hz, standard value 49.8 Hz). The contribution is required to WTs if they are producing more than a minimum power according to primary source availability (30% of the rated power is the standard value). ROCOF is not considered in the present grid code.
	Consent	2	TSO consent is very important since it is considered the most important stakeholder for SI provision. In general terms, the scale-up of the new functionality can improve the company's position (social, environment...) since making renewables more flexible and capable to provide services till now offered only by traditional power plants will remarkably foster energy transition to sustainability.

Table 8.44 Scalability of DFIG for SI provision

Area	Key factor/Subareas	Score	DFIG for SI provision
Technical	**Modularity**	2	In this solution, SI provision is achieved directly from the WT by suitably controlling both the mechanical and the electric/electronic sides of the machine. This allows to intentionally reduce the rotor speed to extract a part of the kinetic energy of rotating parts and transfer it to the electrical network in form of frequency stabilizing contribution. This consists in a temporarily increase of the injected power during under-frequency events, i.e., during the SI provision the generated electrical power exceeds the primary source availability, considering conversion losses. The time trend of the stabilizing contribution is defined according to a regulation law (in particular, it is proportional to ROCOF once activation thresholds are overpassed, and maximum power contribution is not reached) applied by acting on power converters and relative controllers. Then, SI is supplied by WTs depending on their specs, operating conditions, and settings. The overall contribution of the entire plant is influenced by its rated characteristics (number of WTs, etc.) and operating conditions of each WTs, particularly depending on primary source availability. However, since the stabilizing contribution is individually supplied by each WT, scalability analysis will generally refer to the single WT instead of the entire wind farm (wind farm overall rated power is not univocally correlated with the WT size). If all the installed WTs are compliant with SI requirements, then the overall plant can be considered compliant as well. A specific analysis is required to define if the ROCOF measurement has to be centralized or individually performed by each WT, even if the centralized solution could avoid possible instabilities caused by

			errors in local measurement devices. Even if considering the developed solution applied to larger WTs, it seems difficult to obtain the SI contribution if the WT power production is lower than a minimum threshold (reasonably 30% of the WT rated power), since an excessive reduction of rotor speed could impact on the stability of the machine. This suggests to characterize the SI contribution made available by this solution also considering a statistical approach and near time monitoring. Scaling-up the solution means implementing the logic for obtaining the extra active power contribution on larger WTs. The solution modularity is clear, since a part of the controller providing the SI contribution could be the same independently from the WT size. However, make a WT compliant with SI specs means working on the onboard PLC, that it is usually a proprietary part of WT manufacturers. In addition, each WT adopts specific converters and PLCs. This necessarily requires a hard involvement of WT manufacturers, as done during this research project. Particularly, interest of manufacturers could only focus on new or current WT models, whereas the application of the developed logics to older models seems hard to be achieved. Currently, no standards for SI provision exist. This, as well as the required WT manufacturers' involvement, could result in a possible barrier for scaling-up the solution, especially if the service will not be mandatory in future applications.
	Technology evolution	2	A TRL 5 has been reached. The new function was tested in laboratory on a standard WT, not specifically designed to provide SI. More analyses and tests on an actual WT scale are required to validate both modelling results and laboratory tests before implementing the developed solution on a real plant connected to the main grid. This phase requires the direct involvement of WT manufacturer to preserve both certifications and warranties of the WT.
	Interface design	3	In the developed solution, SI is provided individually by each WT which locally measures the ROCOF, then no coordination among WTs have been tested. In a real wind farm, WTs are installed remotely, with distances of several hundreds of meters between towers. If the ROCOF measure will remain independently performed by each WT, severe specs must be considered to avoid measurement errors and delays, which potentially impact on the overall plant behavior in response to the network frequency perturbation. Oppositely, if a single ROCOF measurement device will be installed for the overall power plant (e.g., at the plant POD or close to the control room), a suitable communication infrastructure has to be considered (primarily in terms of latency). No other issues about interface design have been faced.
	Software tools integration	2	Software and firmware integration could result in a barrier for scaling-up the solution since they have to be developed, tested, and installed (in the converter in the navicelle and in the PLC controller) by the WT manufacturer to preserve certifications and warranties of the entire WT. At present, the developed software needs further validation and tests before the implementation on a grid connected WT/plant (this phase could not be carried out in this research project due to lack of time). Advanced versions of software and firmware able to provide SI seem hard to be installed on old WT models due to different technological standard and limited performances of installed equipment.
	Compatibility analysis	3	No evident issues are detected associated with the area where the demo is implemented. The case in which an under-frequency perturbation occurs while the plant is operating at its maximum power requires to be defined in terms of connection rules, since providing SI could lead the overall injected power to overpass the rated power of the plant during the reduced time interval in which the SI is provided (few tens of seconds). About the additional aging of WTs caused by the service, it has not yet been assessed whether the SI supply could limit the lifetime of WTs due to the additional stress associated to the provision of extra power, both in terms of mechanical aspects and electrical/electronic issues. Obviously, it will also depend on the set of parameters imposed to WTs in terms of gain, activation thresholds, maximum required power surplus, etc.
Economics	**Economies of scale**	3	Costs for developing the solution on larger size WT are difficult to be computed from the partner point of view, since this evaluation should be done by the WT manufacturer. In general terms, on modern WT with similar internal architectures, the cost could be limited in relative terms in comparison to other ways to obtain SI, since implementing SI on larger WTs results in a simple adaptation of existing components and technologies (hardware/software), with no expensive equipment to be added. Differently, applying the solution to different WT product families or old WT models could require specific software and firmware that have to be developed and tested. For this reason, it is difficult to identify a general relationship between cost and size of the WT.
	Profitability	3	The cost to adapt modern WTs to SI provision seems limited in comparison with other technical solutions to provide SI, even if the on-field validation process is not completed. It is difficult to evaluate the profitability of the scaled-up solution since no remuneration schemes for the provision of SI presently exist. It seems reasonable that in future the service will be remunerated if the plant will be able

			to provide SI according to defined criteria in terms of performance and availability.
Acceptance	**Regulatory issues**	2	SI is not presently regulated from both the technical and the economical point of view. The Italian grid code currently prescribes a fast frequency regulation, i.e. wind power plants connected to the HV main grid have to be able to supply a surplus of active power (0-10% of the plant rated power, standard value 6%) for a time interval (0-30 s, standard value 10 s) in the case of network under-frequency exceeding an activation threshold (range 49.5-50 Hz, standard value 49.8 Hz). The contribution is required to WTs if they are producing more than a minimum power according to primary source availability (30% of the rated power is the standard value). ROCOF is not considered in the present grid code. It is important to note that laboratory tests confirmed the ability of the analysed WT in providing a power surplus up to 10% the WT rated power, with a time duration from some seconds (if the wind speed is low) up to tens of seconds if the actual power overpass a minimum threshold.
	Consent	2	TSO consent is very important since it is considered the most important stakeholder for SI provision. In general terms, the scale-up of the new functionality can improve the company's position (social, environment...) since making renewables more flexible and capable to provide services till now offered only by traditional power plants will remarkably foster energy transition to sustainability.

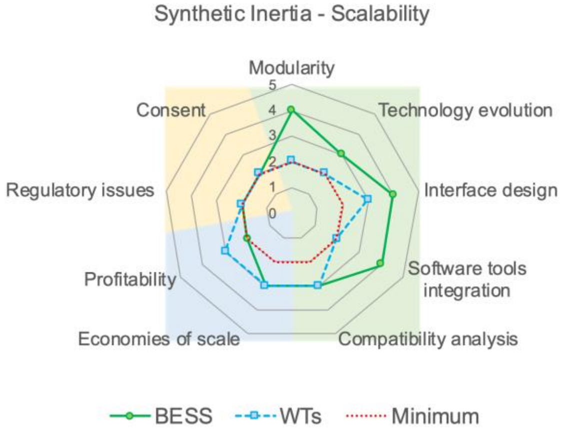


Figure 8.13 Radar plot of RES + BESS and DFIG for SI provision scalability results

Table 8.45 RES + BESS and DFIG for SI provision scalability weighted scores

		SI provision weighted scores	
Area	**Key factor/Subareas**	RES+BESS	DFIG
Technical	**Modularity**	4	2
	Technology evolution	1.8	1.2
	Interface design	3.2	2.4
	Software tools integration	3.6	1.8
	Compatibility analysis	2.1	2.1
Economics	**Economies of scale**	2.7	2.7
	Profitability	1.4	2.1
Acceptance	**Regulatory issues**	1.2	1.2
	Consent	1	1

Table 8.46 RES + BESS and DFIG SI for provision scalability indicators

	SI provision	
Scalability Indicator	RES+BESS	DFIG
Technical	73.5%	47.5%
Economics	51.3%	60.0%
Acceptance	40.0%	40.0%
TOTAL	**62.7%**	**49.3%**

8.2.3.2 RES + BESS and DFIG for AVC provision scalability

The scores assigned to the scalability dimensions of the automatic voltage control provision by RES + BESS and DFIG are in the following Table 8.47 and Table 8.48, respectively. The radar plot of the obtained scores of the two technical solutions is shown in Figure 8.14. Table 8.49 reports the weighted scores and Table 8.50 the indicators that evaluate the scalability of the SI provision technical solutions.

Table 8.47 Scalability of RES + BESS for AVC provision

Area	Key factor/Subareas	Score	RES+BESS for AVC provision
Technical	Modularity	5	In this case, reactive power to support network voltage regulation is primarily supplied by the BESS and secondly by WTs. WTs are priorly required to compensate internal reactive "losses", caused by the reactive power absorption of plant MV cables, which can vary from inductive (during high power production resulting in high currents flowing on cables) and capacitive (caused by no-load reactive absorption of MV cables). Then, the amount of reactive power that the plant can exchange with the grid depends on both the BESS inverter's size and the capability curve of the WTs. The KPI was evaluated considering the AVC provided by the sole BESS, which supplied the required reactive power according to the BESS inverter capability (1 Mvar, both inductive and capacitive). The test did not consider the entire plant capability (about 7 Mvar in terms of reactive power). BESS characteristics could be easily scaled-up depending on technical-economic analysis. It could be done by adding batteries/BMSs/inverters connected in parallel downstream the network POD. Physical dimensions of BESS generally remain very limited in comparison with the wind power plant and required equipment for grid connection. Reactive power demands exceeding the BESS inverters' capability could be supplied by WTs in accordance with WTs' specs, both in terms of capability area and dynamic performance (e.g., the regulating time). From the Master SCADA point of view, no improvements or additional components are required to scale-up the solution size, i.e. the developed device is easily appliable to larger inverters and WTs. In fact, the Master SCADA hardware and the implemented functionalities are independent from both the BESS size and the wind farm characteristics (number and size of WTs, plant topology, distance among WTs in the power plant, etc.). Then, the solution implemented on the Master SCADA level shows a very high level of modularity.
	Technology evolution	4	The solution consists in an innovative additional functionality implemented in plant Master SCADA. It can be a feature of a future standard Master SCADA, then it can be considered at maximum TRL.
	Interface design	4	AVC is provided by the overall plant basing on the BESS characteristics and, secondly, on WTs' specs and plant data. A centralized controller drives the BESS inverter to provide the required reactive power. In the case the required reactive power exceeds the BESS inverter capability area (or if the BESS is unavailable), it evaluates the set points to be sent to each WT, according to the voltage measured at the plant POD and the voltage reference signal (or the reactive power setpoint) received by the TSO. The function is hard to be decentralized to single WTs, since this could lead to instabilities also considering that the internal distribution system may cause differences in voltage levels at each WT. Even in the case WTs are involved in providing the regulation service, no severe characteristics are required to the local communication infrastructure (e.g., in terms of latency). Finally, the centralized control can encourage the scalability as it simplifies the integration of new or larger components.
	Software tools integration	4	The software needed by the hybrid plant (WTs and BESS) to provide AVC was fully in-house developed. Software performances are not affected by the size of the plant. No significant updates to the control logic of the BESS are required even in the case of larger size. However, in the case of larger WTs, the control logic may need to be slightly tuned according to WTs specs (e.g., in terms of dynamic behaviour) with the aim of optimizing the coordination and involvement of WTs in the provision of the service.
	Compatibility analysis	4	A detailed study to characterize the transmission network is required to tune the AVC service in terms of limits in reactive power exchanges at the POD. In terms of plant components' lifetime, the provision of reactive power by the hybrid plant (BESS and WTs) appears to have no significative impact beyond normal usury (caused by higher currents flowing on cables and other electric components).

Economics	**Economies of scale**	2	The installation of a BESS in a wind farm is not a consolidated practice to date, then providing the AVC by making use of the BESS requires that this device is already installed in the site. Present BESS unit costs are hard to be justified by the sole AVC function, even in the case this regulating service will be remunerated in the future and considering larger sizes of plant. This makes difficult to evaluate possible economies of scale for this technology in providing AVC. However, on the other hand, a BESS is able to provide several ancillary services, both to the wind farm itself (capacity firming, generation profile control, etc.) and to the main network. AVC provision does not impact on other ancillary services related to active power (e.g., frequency support, generation time-shift, etc.). Furthermore, AVC capability is mainly related to the size of the inverter of the BESS (and not influenced by its storable energy), then oversizing only this component could make the plant able to provide a larger AVC contribution with limited additional costs. Once the BESS is installed in the plant, few costs are expected for increasing the size of the solution to adapt the specific control to different WT dynamics.
	Profitability	2	It is difficult to evaluate the profitability of the scaled-up solution since no remuneration schemes for the provision of AVC are currently operative. In the case AVC will be remunerated in the future, it could contribute to make the BESS economically profitable (also considering that the regulating contribution is substantially independent from the primary source availability). At present, the Italian grid code imposes to wind farms connected to the HV transmission system an almost rectangular capability curve, then the AVC contribution has no direct impact on current plant profitability, since it does not affect the injection of remunerated active power.
Acceptance	**Regulatory issues**	2	Present grid code imposes the wind farms to make available a defined capability curve, but no remuneration schemes are applied. A pilot project on renewable power plants upgrades for voltage regulation, promoted by the Italian TSO and Italian NRA, is following in the next years and will deepen technologies performance in providing voltage regulation on a system level.
	Consent	3	TSO consent is very important since it is considered the most important stakeholder for AVC provision. In general terms, the scale-up of the new functionalities can improve the company's position (social, environment...) since making renewables more flexible and capable to provide services till now offered only by traditional power plants will remarkably foster energy transition to sustainability. A relevant interest of the TSO exists for exploiting the AVC contribution made available by renewable plants.

Table 8.48 Scalability of DFIG for AVC provision

Area	**Key factor/Subareas**	**Score**	**DFIG for AVC provision**
Technical	**Modularity**	4	Reactive power to support AVC is entirely supplied by WTs according to their capability areas. The capability area of the entire power plant, as seen at the POD, is directly influenced by WTs' specs and plant main characteristics (in. particular, length and rated voltage of internal MV distribution network). WT specs are directly influenced by local grid codes. The participation of the plant to AVC has required the installation of additional components (SCADA and communication channels) that can be easily applied to larger plants since their technical characteristics and cost are independent from the plant size (in terms of both WT rated power and overall number of WTs). The entire capability of the wind farm was tested and issues about the maximum reactive power contribution of WTs (caused by a software configuration of the WT) and the regulation time (controllers and installed WTs are compliant with the previous grid code requirements according to their installation date) were observed. Additional reactive contributions could be obtained by adding reactive compensation devices as modulating capacitor banks or inductors (currently not installed). Physical dimensions of these additional systems are generally limited in comparison with wind power plant and other equipment. Moreover, there could be difficulties in controlling discrete equipment integrated with the WTs plant controller.
	Technology evolution	3	The main barrier to scalability with regards to TRL consists in fulfilling the response time required by the TSO in the current grid code (considering that the latest version of the Italian grid code introduced a fast regulation of reactive power). Particularly, difficulties concern the plant controller, since the overall hardware installed in the communication chain (from the TSO control room to the plant controller, and from this to each single WT controller) introduces a delay that reduces the time available to WTs to reach the required reactive power setpoint. The scaling-up of the solution does not impact on this issue. A TLR level 7 could be considered reached.

	Interface design	4	AVC is provided by the overall plant according to WTs' specs and plant characteristics. A local embedded apparatus computes the overall reactive power basing on both local measures and a reference signal sent by the TSO (reference voltage or required reactive power exchange at the connection node). Then, a reactive power set point for each WT is computed and locally transmitted. In future implementations, the field test suggested to improve the remote communication performances and the system architectures to minimize the time required from receiving the signal from the TSO and sending the reactive power set point to each WT. However, this aspect is not directly related with the scalability of the solution.
	Software tools integration	4	The software to provide AVC is installed in the local embedded device that gather data and information to a centralized datacentre where a second level SCADA is operating. The software was developed in-house by the partner. It is scalable to larger size plant (both in terms of WTs with higher rated power and plants with more WTs). Even in terms of monitoring and controlling interface apparatus, the size of the plant has no significant impact.
	Compatibility analysis	4	No significant incompatibilities between the size of the project and the area where it is located have been addressed during field tests. Scaling-up the solution can make available a larger amount of reactive power, but a specific study on network characteristics is required to better configure the required regulating service. Even if WTs' full capability curve has not been deeply tested in past installations, it seems reasonable to estimate that WTs' lifetime should not be impacted by providing AVC, with exception for few electrical components which could experience more severe operating conditions (in particular, higher currents flowing on cables, transformers, and other devices).
Economics	**Economies of scale**	4	Costs to implement AVC on larger modern wind plants (both in terms of WTs rated power of plants with a higher number of WTs) can be considered negligible in comparison with the cost of the overall generation plant (especially the WTs' cost). The control system including a local SCADA in communication with a remote centralized second-level SCADA seems to be a common practice, then this does not impact in terms of additional costs. An improved version of the developed software can be easily installed and correctly perform the required service. Instead, in the case of small-scale plants or in sites making use of old models of WT (i.e., not in compliance with recent grid code requirements), the solution seems to be applicable with difficulties to be evaluated case-by-case.
	Profitability	3	It is difficult to evaluate the profitability of the scaled-up solution since no remuneration schemes for the provision of AVC are currently operative. At present, the Italian grid code imposes to wind farms connected to the HV transmission system an almost rectangular capability curve, then the AVC contribution has no direct impact on current plant profitability, since it does not affect the injection of remunerated active power. In the case AVC will be remunerated in the future, the additional cost of the plant to contribute in AVC is quite limited in comparison with other solutions and it directly depends on the dynamic performances required to the plant (including both WTs and the control unit) in making available reactive power at the POD.
Acceptance	**Regulatory issues**	2	Present grid code imposes the wind farms to make available a defined capability curve, but no remuneration schemes are applied. Fulfil current grid code requirements in term of time response was the main difficult encountered in the field test. Many causes impacted on this: (i) installed WTs were purchased before the last grid code update, then they are not able to fully meet the requirements in terms of regulation time (2 s for providing 90% of the reactive power set point); (ii) performances of the communication/control chain (local embedded device, based on a Windows embedded operating system, remote communications with a central datacentre for a second level SCADA, local communications with the first level SCADA server through OPC protocol, etc.). A pilot project on renewable power plants upgrades for voltage regulation, promoted by the Italian TSO and the Italian NRA, is following in the next years and will deepen technologies performance in providing voltage regulation on a system level.
	Consent	3	TSO consent is very important since it is considered the most important stakeholder for AVC provision. In general terms, the scale-up of the new functionalities can improve the company's position (social, environment...) since making renewables more flexible and capable to provide services till now offered only by traditional power plants will remarkably foster energy transition to sustainability. A relevant interest of the TSO exists for exploiting the AVC contribution made available by renewable plants.

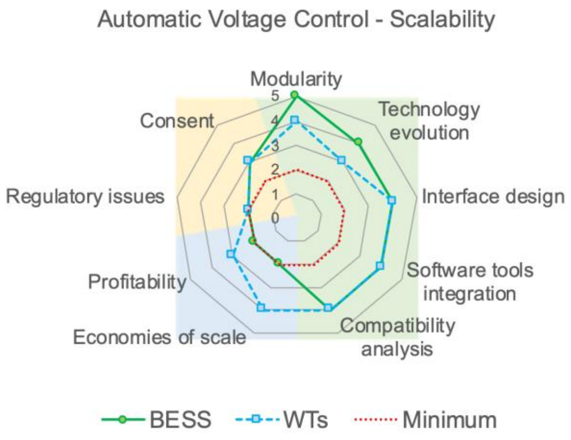


Figure 8.14 Radar plot of RES +BESS and DFIG for AVC provision scalability results

Table 8.49 RES +BESS and DFIG for AVC provision scalability weighted scores

		AVC provision weighted scores	
Area	**Key factor/Subareas**	RES+BESS	DFIG
Technical	**Modularity**	5	4
	Technology evolution	2.4	1.8
	Interface design	3.2	3.2
	Software tools integration	3.6	3.6
	Compatibility analysis	2.8	2.8
Economics	**Economies of scale**	1.8	3.6
	Profitability	1.4	2.1
Acceptance	**Regulatory issues**	1.2	1.2
	Consent	1.5	1.5

Table 8.50 AVC provision scalability indicators

	AVC provision	
Scalability Indicator	RES+BESS	DFIG
Technical	85.0%	77.0%
Economics	40.0%	71.3%
Acceptance	49.1%	49.1%
TOTAL	**68.4%**	**71.0%**

8.2.4 UC 2 replicability results

8.2.4.1 RES + BESS and DFIG for SI provision replicability

Table 8.51 and Table 8.52 report the assigned scores to the replicability dimensions respectively of the RES +BESS and DFIG for synthetic inertia provision. Figure 8.15 shows the radar plot of the replicability results obtained for the two solutions. In Table 8.53 and Table 8.54 the weighted scores and the assessed values of the replicability indicators for the two technical solutions.

Table 8.51 Replicability of RES + BESS for SI provision

Area	**Key factor/Subareas**	**Score**	**RES + BESS for SI provision**
Technical	**Standardization**	3	The solution is at the prototypal stage and can be standardized once TSOs will regulate the provision of SI by renewable power plants. This impacts on several aspects of the BESS providing the stabilizing function, from sizing hardware components to designing software and firmware to be installed in controllers and converters. Finally, the product has to be industrialized and certificated. In fact, one of the targets of the research project is to foster and suggest a clear and rationale definition of needs and technical requirements for this innovative service. Whereas it appears reasonable to standardize the SICD, including the ROCOF measurement device, it should be noted that BESS sizing is also affected by other design drivers depending on other ancillary services suppliable, since its cost is hard to be justified by the sole SI provision, even if remunerated

			in the future. For example, the BESS tested in the pilot site has been sized basically to respect the wind farm production profile scheduled the day ahead. Consequently, in a short term, it is difficult to develop a standardized product that could be easily replicated elsewhere, both in national and international contexts. Standardization can include specific requirements in terms of prescribed accuracy, reliability, and availability of the service. It is important to underline that the developed SICD is very flexible in terms of configuration parameters, then the SI contribution can be easily modified according to specific standards that will be locally applied.
	Interoperability	4	SI provision is regulated by the SICD, consisting in a PLC that measures both frequency and ROCOF and consequently controls the BESS. The SCID can be easily implemented with any PLC in the case it has the appropriate specifications in terms of signal sampling and computational processing capabilities. Grid code standards will have to specify the characteristics of SI contribution, both in terms of accuracy and dynamic performances. The developed solution can be replicated regardless the type of BESS installed. Furthermore, this solution to provide SI does not require specifications on WTs installed in the plant, since SI is obtained by ad additional components in parallel to the traditional plant downstream the network POD. These aspects make the solution easily replicable from the interoperability point of view. Even, the SI contribution obtainable by combining a BESS and a SICD could be suppliable in the absence of primary source, in dedicated storage units and in combination with other types of generation plants (e.g., photovoltaic plants).
	Network configuration	4	No relevant barriers in replicability were detected from the network configuration point of view. It is recommended a detailed grid analysis to determine the proper characteristics of the SI contribution and, in case, to identify limits in active power injection and absorption. The availability of the SI contribution is independent from the primary source. This remarkably increases its importance in a future scenario with huge quantity of renewables and reduction of traditional inertia in the system. On the other hand, BESS availability is influenced by the way the storage system is managed in accordance with the provision of other, potentially remunerated, ancillary services (e.g., in terms of internal state of charge), then rules to preserve the SI contribution in case of network events have to be defined. The solution can be replicated also at different voltage levels, even if technical and cost/benefit analyses are required to better address the point.
Economics	**Macro-economic factors**	2	Analyses are currently underway to assess the impact of macro-economic factors on other possible plants where the solution could be replicated. No specific conclusions can be done at the moment since no remuneration schemes for the SI contribution has been developed.
	Market and business model	2	Analyses are currently underway to evaluate the best business and market model under which the solution could be economically viable. Certainly, the lack of a market for the provision of SI, both in Italy and in other counties, is a high barrier to the deployment of the new service. SI provision will difficultly justify the BESS cost, then BESS sizing is expected to be impacted by several other drivers to consider all the possible ancillary services that a storage unit can supply, in particular the ones that will be remunerated according to local standards.
Regulatory	**Regulatory issues**	2	Lack of remuneration schemes is a relevant barrier in terms of replicability. SI provision through BESSs (power-intensive use of the storage system) implies that components are more stressed respect to other operative modalities in which charging and discharging times are longer (energy-intensive uses). Therefore, a remuneration would be appropriate at least to cover the extra costs both in terms of installation and accelerated aging. Since the stabilizing function is not currently defined by grid codes (in terms of required contribution, activation thresholds, admitted delay and accuracy, etc.) and a certified characterization of frequency perturbation (number of events, perturbation entities in terms of frequency deviations and ROCOF, etc.) does not exist, it is difficult to investigate how much and how many times the service will be required. Considering the entire power system, in the future, inertia support could come also from renewable sources. Particularly, this solution makes the SI contribution continuously available if BESS operating conditions are respected (e.g., in terms of internal state of charge) and independently from the primary source availability. This approach can also be replicated in combination with other types of generators (e.g., photovoltaic plants) or in stand-alone BESS units. Furthermore, SI response is completely configurable through a suitable set of parameters, then it can be adapted according to specific network requirements.
	Acceptance	3	Certification requirements according to local standards could be a problem in terms of acceptance. Since the solution is appliable also to other generation technologies and to stand-alone BESS units, a great interest is expected if a suitable remuneration scheme will be introduced for the service.

Table 8.52 Replicability of DFIG for SI provision

Area	Key factor/Subareas	Score	DFIG for SI provision
Technical	Standardization	2	The solution is currently being tested in the laboratory. Field tests are needed to accurately estimate the requirements in terms of standardization, industrialization, and certification. Furthermore, it may be difficult to standardize the solution as the provision of SI directly by WTs could be implemented differently by each WT/converter manufactures. Standardization can include specific requirements in terms of prescribed accuracy, reliability, and availability of the service. Particularly, a standardized approach for the evaluation of the ROCOF could be suggested in the case this network measurement is independently performed by each WT. This allows to obtain a correct overall dynamic response of the entire plant and to preserve the system from possible instabilities.
	Interoperability	2	The developed solution, independently applied by each WT, does not require to interact with the local centralized plant controller or other remote apparatus. All the devices involved in the SI provision, from the frequency/ROCOF measurement to PLC controllers and converters/drives, are installed in the WT. Field tests are needed to accurately assess the interoperability of the solution and, in detail, to investigate if a centralized measurement of frequency and ROCOF could improve the dynamic response of the entire power plant in the case of severe network perturbations. In this case, a suitable communication system is required to assure required availability and admitted latency. The set of parameters that define the SI contribution (e.g., gain, activation thresholds, hysteresis behavior, etc.) are configurated in the WT controller (usually property of WT manufacturer and not accessible to the plant manager).
	Network configuration	3	Even if providing SI in different locations may have different levels of effectiveness depending on the grid configuration, no barriers in replicability were detected from the network configuration point of view. Differently, it has to be taken into account that WTs can be able to provide SI only if they operate above a minimum generation level (e.g., 30%) to prevent shutdowns due to excessive rotor speed reduction. Then, since the actual SI contribution availability is strongly related with the primary source, wind speed distribution plays a crucial role when the solution is replicated in different locations. A suitable characterization of primary source availability (in space and time) is then required to address typical trends on daily and seasonal intervals, and to estimate the SI contribution consequently. Real-time measurements from wind plants can also be used to dynamically quantify the stabilizing contribution made available by plants equipped with WTs able to provide SI.
Economics	Macro-economic factors	2	Analyses are currently underway to assess the impact of macro-economic factors on other possible plants where the solution could be implemented. Results strongly depend country by country on wind plant diffusion (which impacts on the level of interest of WT manufactures for the specific market area), local market characteristics, technical normative framework and grid code requirements.
	Market and business model	2	Analyses are currently underway to evaluate the best business and market model under which the solution could be economically viable. Certainly, the lack of a market for the provision of SI, both in Italy and in other counties, is a high barrier to the deployment of the new service. In this case, SI provision could imply a small additional capital cost for WTs according to service specs that will be introduced in each country, even if a sort of standardization could be suggested to limit costs for WT customization and certification. It should be noted that, standing on preliminary laboratory results, sizing of main devices and control logics are quite similar to the ones currently required to support fast frequency regulation as prescribed in some grid codes (e.g., Italy, Canada, etc.).
Regulatory	Regulatory issues	3	Lack of remuneration schemes is a relevant barrier in terms of replicability. Additionally, since the stabilizing function is not currently defined by grid codes (in terms of required contribution, activation thresholds, admitted delay and accuracy, etc.) and a certified characterization of frequency perturbation (number of events, perturbation entities in terms of frequency deviations and ROCOF, etc.) does not exist, it is difficult to investigate how much and how many times the service will be required. Then a concrete estimation of machine aging is not addressable at the moment. In general, a remuneration would be appropriate at least to cover the extra costs both in terms of installation and increased aging. Considering the entire power system, in the future, inertia support could come also from renewable sources. This could solve the issue of system inertia reduction caused by an increase of wind exploitation, since SI could be available when wind farms are producing energy (i.e. WT power

			injection overpasses a minimum limit to preserve the machine stability, e.g., 30% of the rated power).
	Acceptance	2	The acceptance of WT manufacturers is required to industrialize and certificate technologies able to provide SI. In fact, it seems that the plant owner cannot develop an in-house solution to provide SI without affecting the performance and reliability of the WTs, which means impacting on machine warranties. Further considerations can be made as the solution will conclude field testing.

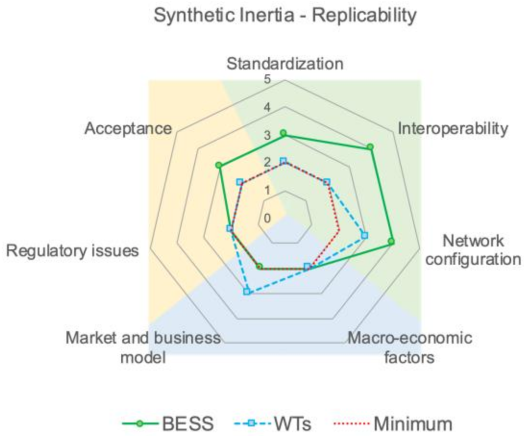


Figure 8.15 Radar plot of RES + BESS and DFIG for SI provision replicability results

Table 8.53 RES + BESS and DFIG for SI provision replicability weighted scores

		SI provision	
Area	**Key factor/Subareas**	RES+BESS	DFIG
Technical	**Standardization**	3	2
	Interoperability	3.6	1.8
	Network configuration	3.2	2.4
Economics	**Macro-economic factors**	1.5	1.5
	Market and business model	1.8	2.7
Regulatory	**Regulatory issues**	1.8	1.8
	Acceptance	1.8	1.2

Table 8.54 RES + BESS and DFIG for SI provision replicability indicators

	SI provision	
Replicability Indicator	RES+BESS	DFIG
Technical	72.6%	45.9%
Economics	40.0%	50.9%
Regulatory	48.0%	40.0%
TOTAL	**57.1%**	**45.8%**

8.2.4.2 RES + BESS and DFIG for AVC provision replicability

Table 8.55 and Table 8.56 report the assigned scores to the replicability dimensions respectively of the weather-based DTR and the sensor-based DTR. Figure 8.16 shows the radar plot of the DTR replicability results obtained for the two solutions. In Table 8.57 and Table 8.58 the weighted scores and the assessed values of the replicability indicators for the two technical solutions.

Table 8.55 Replicability of RES + BESS for AVC provision

Area	**Key factor/Subareas**	**Score**	**RES + BESS for AVC provision**
Technical	**Standardization**	3	Since at grid code level the provision of the AVC by wind farms has not been standardized yet, it is difficult to predict which standards (reliability, accuracy, and availability) might help the replication of the solution in other plants. Furthermore, it is difficult to indicate a standardized size of the BESS (to provide the AVC service) as a function of the plant rated power, since the overall plant capability curve (prescribed by the grid code) can be fulfilled by both the BESS's and the WTs' contributions. Indeed, the lack of remuneration of the service does not allow direct economic evaluations. At present, the size of the BEES is optimally choose also evaluating the provision of other remunerated services,

			even if the BESS inverter size is the main characteristic that directly impact on the AVC provision (whereas storable energy has no significant role in this). In any case, the solution implemented on Master SCADA level uses standard communication protocols that can increase the compatibility of the solution with other storage devices.
	Interoperability	4	Thanks to the standard communication protocol adopted in the demo plant, the solution can be implemented on others Master SCADA devices. If the plant has already installed a BESS, implementing the AVC consists in an update of the control logic of the BESS Master SCADA, with no large investments required.
	Network configuration	4	No barriers in replicability were detected from the network configuration point of view. In fact, the ability of the system in exchanging reactive power seems not affected by the area where the plant is located if network voltage at the POD remains inside the admitted tolerance around the rated value. If network voltage exceeds admitted limits, the plant capability curve is reduced. Instead, the effectiveness of controlling reactive power at the plant POD in terms of AVC is directly impacted by network data, in particular the network rated voltage (transmission/sub-transmission system) and grid parameters such as the equivalent impedance. Obviously, since the innovative function is applied to a power plant exploiting a renewable and partially unpredictable energy source, a part of the availability of the plant in providing AVC (i.e., the contribution from the WTs) may be influenced by the availability of the primary source. According to the current Italian grid code, a reduction in reactive power availability is admitted in the case the power plant active power generation drops under 10-20% (i.e. the wind speed is quite close to the cut-in value). However, it is remarkable to note that the AVC contribution made available by the BESS is substantially independent from WTs' operating conditions, then BESS can be continuously available to support network voltage independently from primary source availability. This means that it can be exploited independently from the plant operating condition and, in case, as an individual resource or in combination with other generation plants (e.g., photovoltaic plants, where a storage device could be installed also to provide other ancillary services to the network or to the power plant itself). As a general recommendation, implementing the AVC on a new plant requires a preliminary grid analysis to assess the hosting capacity at the POD, the maximum reactive power contribution, and its effectiveness in terms of AVC. In future application, WT manufacturers could investigate the exploitation of inverters installed in DFIG WTs (inverter rated power about 30% of the WT rated power) and in full-converter WTs (inverter rated power equal to the WT rated power) to support AVC even if wind availability is very low or completely absent.
Economics	**Macro-economic factors**	2	Analyses are currently underway to assess the impact of macro-economic factors if the solution is replicated in other plants, both at national and international level. Remuneration of AVC service or adaptation of grid code to prescribe this functionality plays a significant role in this analysis.
	Market and business model	2	Market and business model analyses strongly depend on local approaches to the AVC service. Particularly, AVC support could be mandatory or voluntary, remunerated or not. Focusing on the developed solution and referring to current market data, BESS cost could be justified in the case it provides several remunerated ancillary services, both in active power (capacity firming, generation profile control, etc.) and in reactive power (AVC).
Regulatory	**Regulatory issues**	3	From the economic point of view, solution replicability strongly depends on regulatory aspects defining if AVC will be mandatory or voluntary, remunerated or not. Technical issues involved by local grid codes seem to be resolvable by adapting the developed solution to local specifications (e.g., capability curve to be provided by the plant, dynamic response time, communication infrastructure between TSO and wind farm, etc.).
	Acceptance	4	The innovative solution tested in the demo plant can be easily applied to new plants, both at national or international level, with adaptations according to local technical and economical specifications. It could be developed during revamping/repowering of existing power plant too.

Table 8.56 Replicability of DFIG for AVC provision

Area	Key factor/Subareas	Score	DFIG for AVC provision
Technical	**Standardization**	2	At present, the solution is not fully compliant in terms of AVC with standard requirements included in the current grid code (it is compliant with the previous version of the grid code). Particularly, when reactive power is delivered under remote control, it is difficult to comply with the timescales defined in the grid code due to the delay introduced in the communication chain between the TSO and each single WTs (first level SCADA hardware configuration, local

			communications through OPC protocol, etc.). Furthermore, installed WTs are compliant with the previous grid code in terms of dynamic response to a variation of the reactive power set point and problems in providing the entire reactive contribution arose during the test due to a software issue identified by the WT manufacturer. This results in a barrier for the direct standardization of the developed solution. In addition, the solution (implemented on the local embedded) needs to be interfaced (trough the Master SCADA) with the WT's regulator. Usually, this is not a standard component as it differs for each WT model/manufacturer (e.g., in term of performance, communication protocol, etc.). The part of the developed solution that could be easily standardized is the software developed in the local embedded. The reliability is medium - high. Nevertheless, some improvements could be added to increase it.
	Interoperability	2	From the interoperability point of view, the main barrier detected is the interface between the local embedded device and the WT plant controller. In the demo plant, this was done via OPC (Open Platform Communication) which introduces a certain time delay that makes the solution potentially not compliant with requirements in terms of dynamic response. Furthermore, the used protocol depends on the model/manufacturer of the WT, making interoperability of the solution a bit complex and suggesting a standardization of this device or, at least, of its interfaces.
	Network configuration	4	No barriers in replicability were detected from the network configuration point of view since the wind farm is able to provide the entire capability area in the case the network voltage differs from the rated value less than admitted thresholds. Otherwise, the reactive power contribution made available by the generation plant is reduced according to the current grid code. From the network configuration point of view, providing AVC in different locations may have different results depending on the grid equivalent characteristics at the POD. When AVC is fully provided by WTs, wind availability plays a crucial role since the service is directly related to the amount of primary source. This aspect has to be investigated to address the availability of the plant in supporting AVC, also considering seasonal/daily typical variations. In the case the wind speed is very low, but higher than the cut-in value (reported in WT datasheet), the availability of reactive power exchange is reduced respect to WTs operating at higher loading in terms of active power production. If the wind speed drops under the cut-in speed, the plant can regulate the reactive power at the POD only acting on compensating devices that can be optionally installed in the site to fulfil the entire capability area required by the grid code (e.g., modulating capacitor banks or inductors). Finally, extending the solution to other wind farms, the overall performances may be different as the capability curve is directly related to the type/model of WTs installed in the plant. In future application, WT manufacturers could investigate the exploitation of inverters installed in DFIG WTs (inverter rated power about 30% of the WT rated power) and in full-converter WTs (inverter rated power equal to the WT rated power) to support AVC even if wind availability is very low or completely absent.
Economics	**Macro-economic factors**	2	Analyses are currently underway to assess the impact of macro-economic factors if the solution is replicated in other plants, both at national and international level. Remuneration of AVC service or adaptation of grid code to prescribe this functionality plays a significant role in this analysis.
	Market and business model	3	Market and business model analysis strongly depends on local approaches to the AVC service. Particularly, AVC support could me mandatory or voluntary, remunerated or not. If the AVC support is provided by WTs, it is important to note that new WT models can implement the AVC with limited additional costs. Oppositely, in the case of old WT models, it is quite difficult to assess if the solution is feasible from both the economical and the technical point of view. However, analyses are currently underway to assess the best business and market model under which the solution is economically viable.
Regulatory	**Regulatory issues**	3	From the economic point of view, solution replicability strongly depends on regulatory aspects defining if AVC will be mandatory or voluntary, remunerated or not. Technical issues involved by local grid codes seem to be resolvable by adapting the developed solution to local specifications (e.g., capability curve to be provided by the plant, dynamic response time, communication infrastructure between TSO and wind farm, etc.).
	Acceptance	3	The AVC provision obtained by WTs can be easily applied to new plants, both at national or international level, with adaptations according to local technical and economical specifications. An industrial solution for control and communication devices could be developed starting from results obtained in this project, with the aim to solve some issues regarding the dynamic response of the plant while providing AVC (e.g., latency, computation time and communication delays). The solution could be applied also during revamping/repowering of existing power

			plants if WTs will be replaced with modern machines able to suitably regulate their reactive power exchange with the plant.

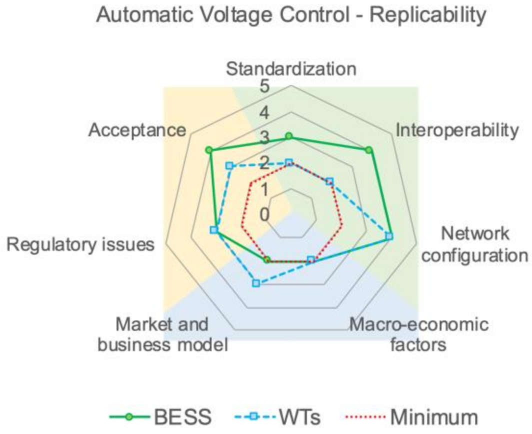


Figure 8.16 Radar plot of RES + BESS and DFIG for AVC provision replicability results

Table 8.57 RES + BESS and DFIG for AVC provision replicability weighted scores

		AVC provision	
Area	**Key factor/Subareas**	RES+BESS	DFIG
Technical	**Standardization**	3	2
	Interoperability	3.6	1.8
	Network configuration	3.2	3.2
Economics	**Macro-economic factors**	1.5	1.5
	Market and business model	1.8	2.7
Regulatory	**Regulatory issues**	2.7	2.7
	Acceptance	2.4	1.8

Table 8.58 AVC provision replicability indicators

	AVC provision	
Replicability Indicator	RES+BESS	DFIG
Technical	72.6%	51.9%
Economics	40.0%	50.9%
Regulatory	68.0%	60.0%
TOTAL	**62.2%**	**53.7%**

8.2.5 UC 3 scalability results

8.2.5.1 DSR for AVC provision scalability

The scores assigned to the scalability dimensions of the DSR for automatic voltage control provision are in the following Table 8.59. In Figure 8.17 the radar plot of the obtained scores is shown. Table 8.60 reports the weighted scores and Table 8.61 the indicators that evaluate the scalability of the DSR for AVC provision.

Table 8.59 Scalability of the DSR for AVC

Area	**Key factor/Subareas**	**Score**	**DSR for AVC**
Technical	**Modularity**	3	The hardware and the aggregator platform are modular. Two main barriers have been detected: 1) the absence of an automatic interface for remotely controllable loads; 2) the absence of a logic for converting the set point coming from the aggregator to a signal for controlling the load.
	Technology evolution	3	The actual TRL ensures the scalability of the solution with reference to the aggregator side. On the other hand, the lack of

			automatic control of the local resources represents the main technological barrier encountered.
	Interface design	3	The interface operator-aggregator is viable. The limit is related to the lack of automatic control for local resources and to the need of short time of action. Improvements of TRLs can help the scalability in terms of amount of controllable power.
	Software tools integration	4	The software is easily scalable and not affected by the plant size.
	Compatibility analysis	2	The connectivity of the demo obtained by using 4 G LTE router is not adequate for AVC
Economics	**Economies of scale**	4	If the size of the flexibility resource increases, no extra costs are foreseen. If complexity or data acquired increase, it is expectable that the costs for the aggregation platform and data storage can increase marginally
	Profitability	4	Demo did not make to emerge barriers. However, the project is not economically viable, being the rated values of the resources involved.
Acceptance	**Regulatory issues**	4	Regulatory barriers affecting the size and scope of the solution are not expected. The evolution of regulations could favour cost-benefit ratio.
	Consent	4	Identification of incentives can be opportune in order to obtain stakeholder acceptance. Scale-up of the new functionalities can improve the company's position (social, environment...).

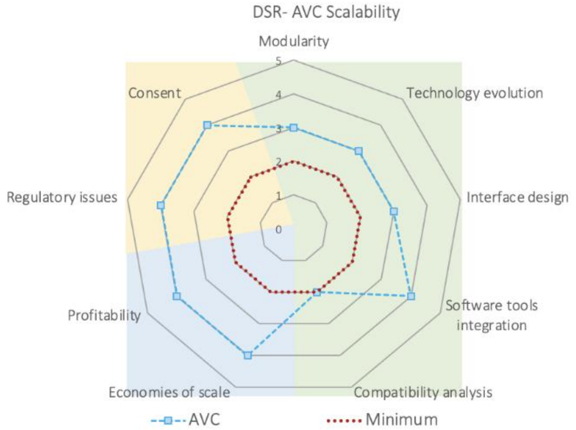


Figure 8.17 Radar plot of the DSR for AVC scalability results

Table 8.60 DSR for AVC scalability weighted scores

Area	**Key factor/Subareas**	DSR for AVC
Technical	**Modularity**	3.0
	Technology evolution	1.8
	Interface design	2.4
	Software tools integration	3.6
	Compatibility analysis	1.4
Economics	**Economies of scale**	3.6
	Profitability	2.8
Acceptance	**Regulatory issues**	2.4
	Consent	2.0

Table 8.61 DSR for AVC scalability indicators

Scalability Indicator	DSR for AVC
Technical	61.0%
Economics	80.0%
Acceptance	80.0%
TOTAL	**68.7%**

8.2.6 UC 3 replicability results

8.2.6.1 DSR for AVC provision replicability

Table 8.62 reports the assigned scores to the replicability dimensions of the DSR for automatic voltage control provision. Figure 8.18 shows the radar plot of the DSR for AVC provision replicability results. In Table 8.63 and Table 8.64 the weighted scores and the assessed values of the replicability indicators of the DSR for AVC provision.

Table 8.62 Replicability of the DSR for AVC

Area	Key factor/Subareas	Score	DSR for AVC
Technical	**Standardization**	3	The solution implemented can be replicable, but some barriers have been found. In particular, the communication standard protocol requires tests and verification to have cost-benefits. A standardised base load forecaster could help the replicability of the solution. Further analyses and verification are needed.
	Interoperability	3	The main barrier to replicability is related to the characteristics of the local resource flexibility. It depends on the customer and the flexibility resources identified. A local customization of the set up is always required.
	Network configuration	4	The solution implemented is potentially applicable in other industrial contexts once a remote automatic control of the local resource has been implemented. Investments have to be verified, in particular, with reference to the level of impact on the site's consumption.
Economics	**Macro-economic factors**	3	The solution is potentially replicable, but further developed are necessary. The profitability of the solution depends on local territorial factor, specifically in terms of economic remuneration of the service.
	Market and business model	3	Although the solution is potentially replicable, further analyses are required to verify the economic viability related to the complexity of the different territorial and market scenarios.
Regulatory	**Regulatory issues**	3	The solution is potentially replicable but further developed are necessary in particular depending on the grid codes and regulations of the countries where this solution should be replicated. Response times and accuracy requirements in terms of set points satisfaction can be conditioned by national and regional regulation rules.
	Acceptance	3	The solution is potentially replicable but further developments are necessary to make the solution acceptable.

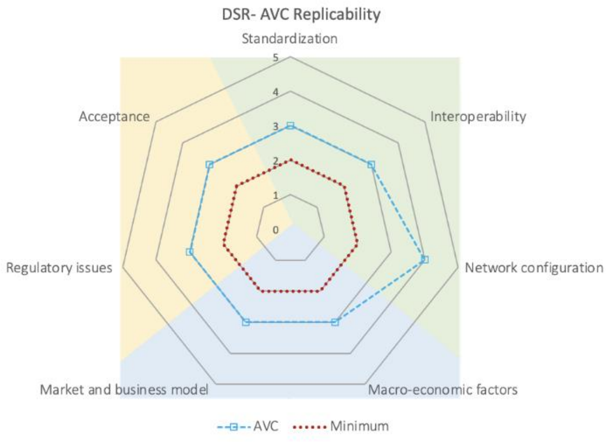


Figure 8.18 Radar plot of DSR for AVC replicability results

Table 8.63 DSR for AVC replicability weighted scores

Area	**Key factor/Subareas**	DSR for AVC
Technical	**Standardization**	3.0
	Interoperability	2.7
	Network configuration	3.2
Economics	**Macro-economic factors**	2.3
	Market and business model	2.7
Regulatory	**Regulatory issues**	2.7
	Acceptance	1.8

Table 8.64 DSR for AVC replicability indicators

Replicability Indicator	DSR for AVC
Technical	65.9%
Economics	60.0%
Regulatory	60.0%
TOTAL	**62.7%**

8.3 Results of quantitative SRA

8.3.1 Quantitative SRA applied to UC2 functionalities

This section reports the results of the application of the procedure shown in Figure 6.2. The study aimed at estimating the benefits achievable at national level, once the solutions implemented in UC2 will be scaled up to larger WTs/BESSs and plants and will be replicated on all the installed wind farms, according to the goals reported in the Italy's PNIEC2030 (Table 6.5).

The histogram in Figure 8.19 reports the installed power in each province, in [MW] (left vertical axis), from 2015 to 2019. Only provinces where wind farms are installed are reported in the figure. Background colors represent the Italian bidding zones (named as NORD, CNOR, CSUD, SUD, SICI, SARD). Fine lines plot the annual unit production of each province from 2015 to 2019, in [h/y] (right vertical axis), whereas the bold line is the average unit production, in [h/y]. It is appreciable the variability of the wind source year by year, as well as according to geographical areas.

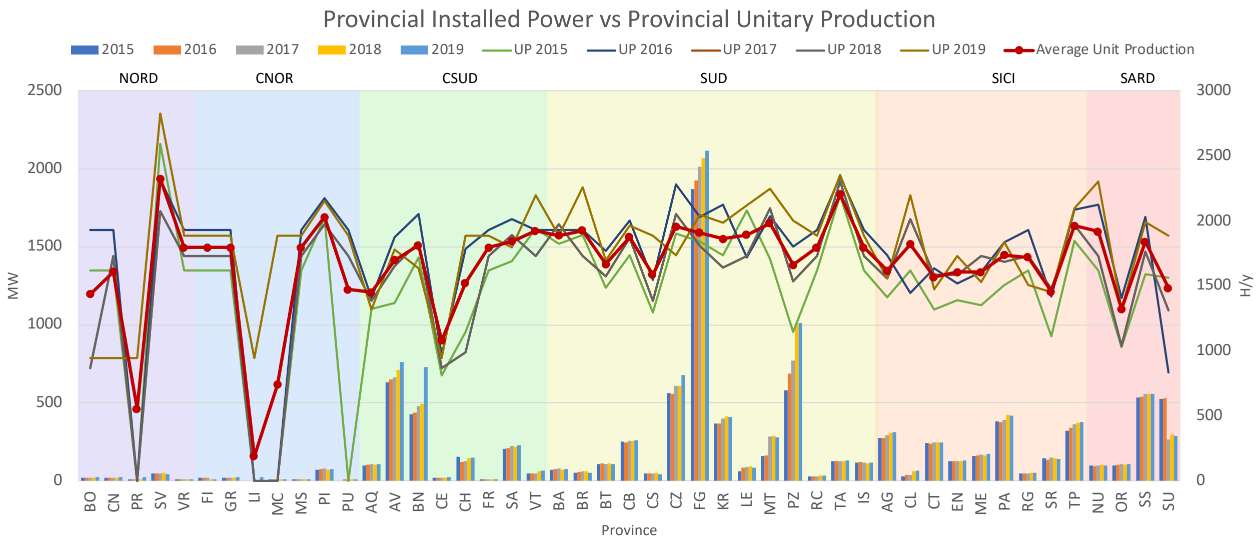


Figure 8.19 Overall rated power and unit production of installed wind farms (2015 to 2019)

8.3.1.1 SI

Referring to SI, a generation coefficient of 30% was considered. Figure 8.20 reports the number of hours in which the hourly unit production of each province overpasses this threshold. The dotted line is the average among the fine lines, which refer to each year from 2015 to 2019. An anomaly is present in the data referring to 2017 as the unit producibility remains constant for all the provinces included in the same bidding zone. However, results are still significant.

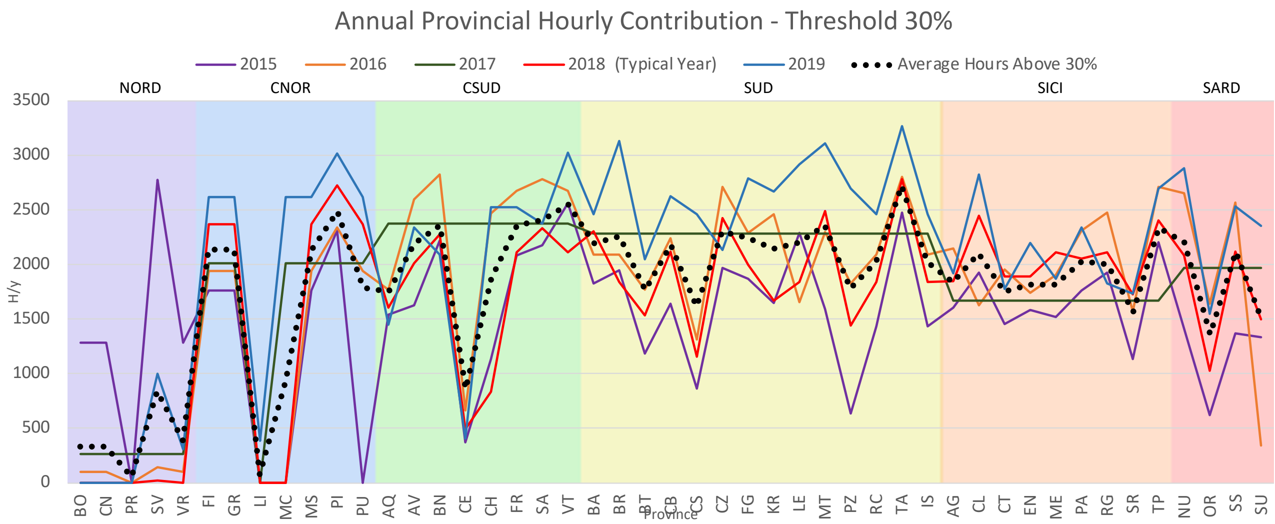


Figure 8.20 Number of hours in which wind farms are able to provide SI according to the considered threshold on generation coefficient (30%) – years 2015 to 2019 and average

Referring to the average trend in Figure 8.20, Figure 8.21 reports the number of hours in which the amount of primary source was sufficient to made available the SI contribution, subdivided for season (in [h/y], left vertical axis). In the same picture, the installed rated power of wind farms in 2019 is reported, in [MW] (dotted black line referring to right vertical axis), as well the annual unit production, in [h/y] (asterisks). Additionally, seasonal data were analyzed depending on daily intervals (night/morning/afternoon/evening) to address when the SI contribution is more probable to be available.

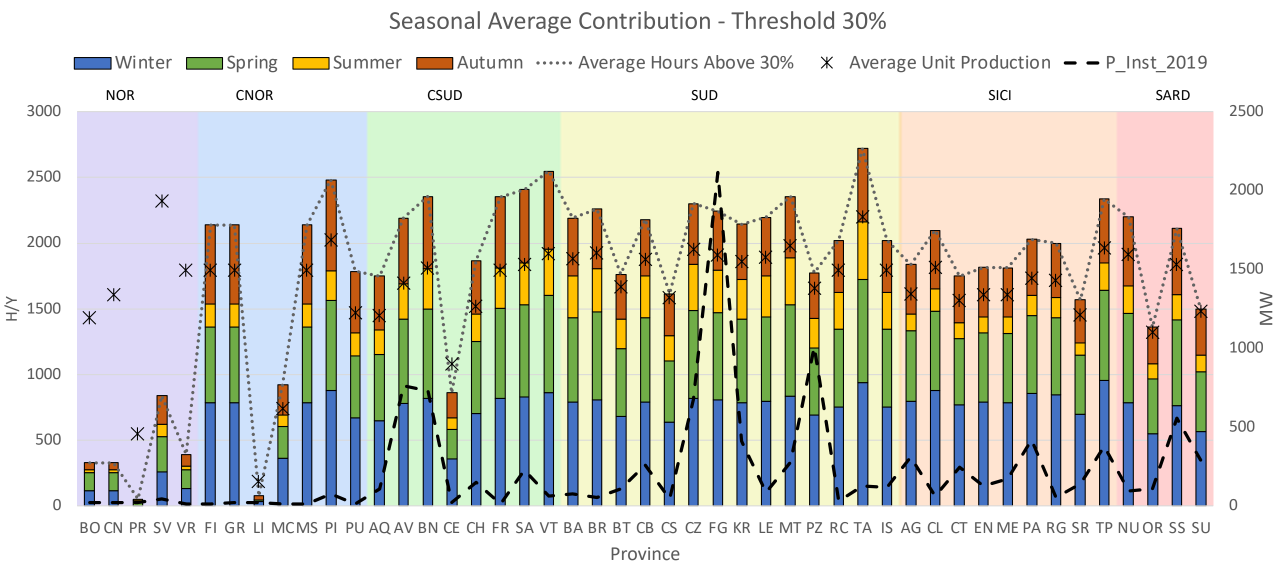


Figure 8.21 Unit production (asterisks), installed power in 2019 (dotted line) and number of hours in which wind farms are able to provide SI according to the considered threshold on generation coefficient (30%)

Some remarks can be done by comparing and analyzing previous figures:

- Availability of wind source influences the number of hours in which WTs are able to provide the service. For example, the year with the lower unit production at national level was 2015 (1620 h/y) and this reflected in terms of number of hours exceeding the minimum SI generation coefficient. Conversely, the 2019 (1885 h/y) resulted the best year in terms of primary source to provide SI. For the province of Taranto (TA), the number of hours in which the primary source availability is enough to provide SI was 3133 h/y.
- There is not a direct correlation between province unit production and number of hours in which the SI provision is obtainable according to the assigned threshold on generation coefficient. In fact, it depends on the hourly profile of generation, as demonstrated by the duration curves in Figure 8.22-a. Taking for example the province of Taranto (TA) in 2019, the availability in providing SI (more than 3300 h/y) can be higher than the annual unit production (about 2350 h/y) if the production profile remains above the minimum value of 30% for a relevant time. Differently, if the plant operates at low power, i.e. the primary source is very low, the availability in providing SI drops down respect to the unit production, as for the province of Caserta (CE) in 2019. Figure 8.22-b reports the results referred to the province of Foggia (FG), which hosts the highest value of installed power.
- The availability of primary source to supply SI strongly depends on the season. In general, it is remarkably larger in winter and spring, whereas summer is the season in which the contribution is minimum.
- The availability of primary source to supply SI is quite homogeneous in terms of daily intervals, except for Sicily where the afternoon availability is significantly larger than other periods during the summer (however, the overall summer contribution is quite low respect to other seasons).

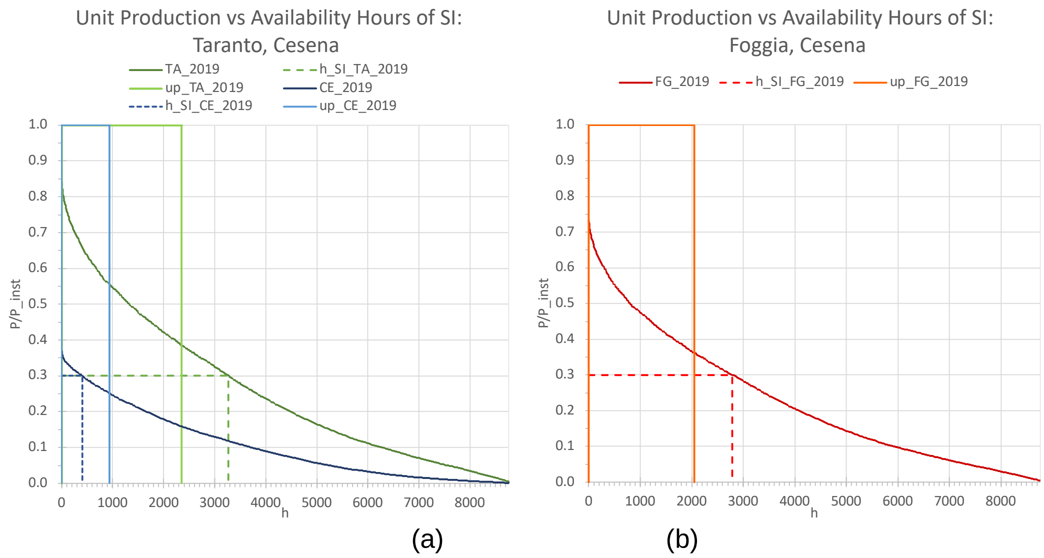


Figure 8.22 Duration curve of the hourly unit production for some provinces: TA/CE (a) and FG (b)

Finally, Figure 8.23 reports:

- The daily curve of the profile of the unit production in Italy in 2019;
- The daily curve of the profile of the unit production in Italy, considering for each hour only provinces in which the generation coefficient to make available SI is overpassed;
- In bold line, the daily curve of the profile of the installed rated power in Italy, considering for each hour only provinces in which the generation coefficient to make available SI is overpassed.

Considering that results of UC2 suggest to limit the SI contribution to 10% of the rated power if a minimum threshold in terms of generation coefficient (30%) is reached, it is possible to define the overall SI contribution as one tenth of the bold line in Figure 8.23 while referring to 2019. According to PNIEC2030 goals, considering that wind plants overall rated power was 10.7 GW in 2019, the SI stabilizing contribution could increase up to 18.0% of the bold line in Figure 8.23, which means about 1.90 GW in terms of maximum contribution, whereas at least 1.30 GW is available during the 2000 hours when the wind production is higher at national level.

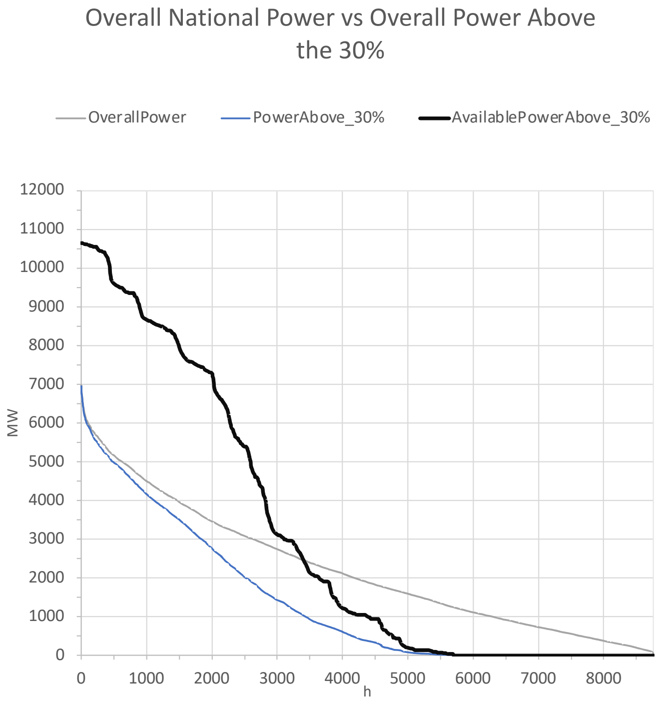


Figure 8.23 Duration curve of: overall unit production, overall unit production considering only plants exceeding the SI threshold (generating coefficient 30%), overall rated power considering only plants exceeding the SI threshold, in bold (generating coefficient 30%)

8.3.1.2 AVC

A similar approach is considered to quantify the amount of reactive power that AVC could make available, considering that WTs can currently provide the service only above a minimum generation coefficient. A threshold of 10% is here considered.

Figure 8.24 reports data for each year from 2015 to 2019. The dotted line refers to the average availability for each province, in [h/y]. It clearly appears that, in the south of Italy (where the largest part of overall wind capacity is installed), plants can provide AVC for a relevant time (for the bidding zone named SUD, the AVC availability varies from about 5000 h/y to more than 6000 h/y), significantly higher than half of the overall year duration (4380 h/y). It clearly appears that the AVC availability depends on the local unit production, but it is remarkably higher in numeric value. For the same area, the range of the AVC availability drops to about 3000-4000 h/y in the case the AVC activation threshold is increased to 20%.

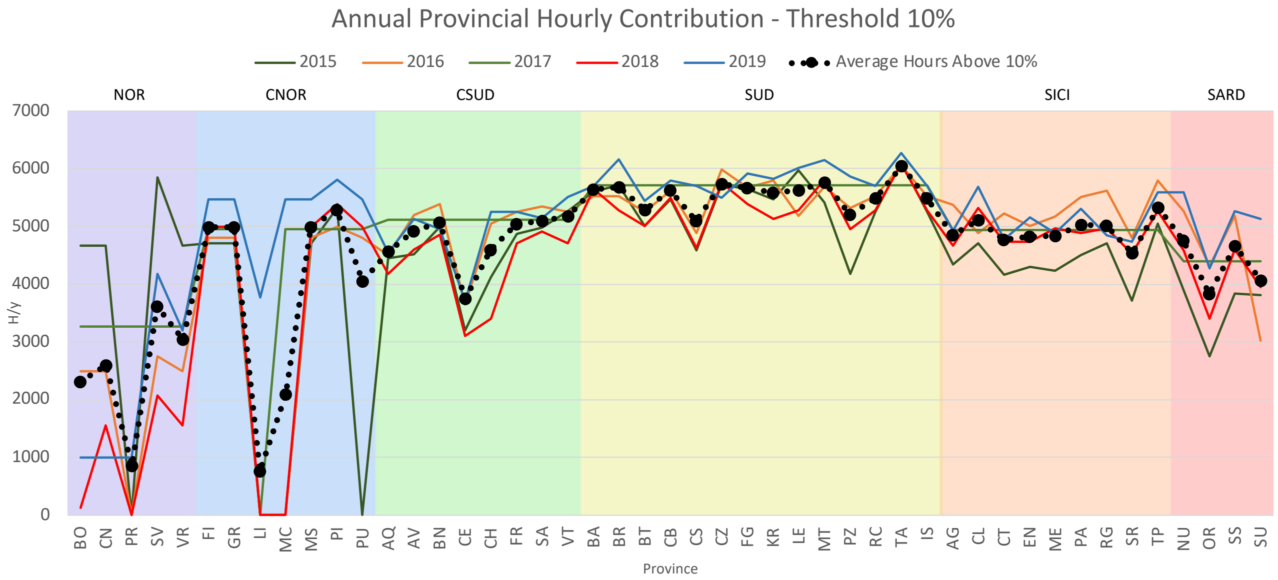


Figure 8.24 Number of hours in which wind farms are able to provide AVC according to the considered threshold on generation coefficient (10%) – years 2015 to 2019 and average

By lowering the activation threshold in comparison with SI, the AVC availability distribution depending on season is more homogeneous, as depicted in Figure 8.25. Data refers to the average of the considered 5 year interval.

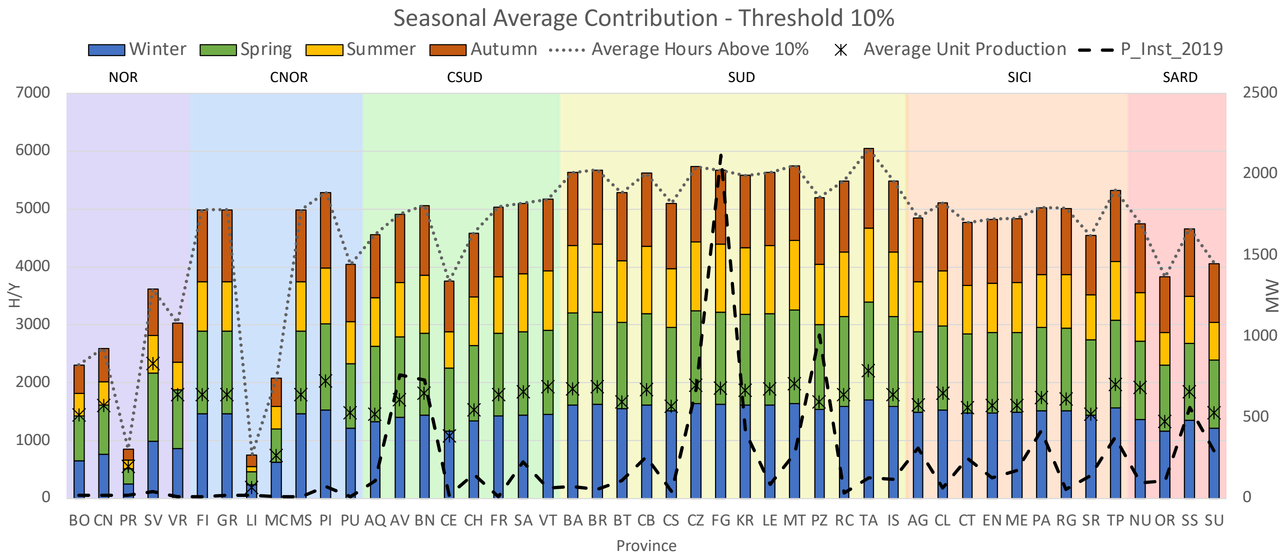


Figure 8.25 Unit production (asterisks), installed power in 2019 (dotted line) and number of hours in which wind farms are able to provide AVC according to the considered threshold on generation coefficient (10%)

For AVC, since the effectiveness of providing reactive power for supporting voltage regulation strongly depends on the geographic area, results are not summarized at national level and a classification for bidding zone is maintained.

It is possible to consider the current grid code in terms of wind farms capability area, which means reactive power exchange settable between -35% and +35% of the plant available rated power (with few dispensations in providing inductive power to the grid when the generation is close to the rated value) if the threshold in terms of generation coefficient is overpassed (a 10% is considered). Furthermore, the expected growth in wind farm installation according to PNIEC2030 goals has to be considered, i.e. +80% of overall installed power in comparison with 2019. Then, considering all the plants compliant with AVC requirements, for each bidding zone, the duration curve of the AVC contribution estimated in 2030 could be, in [Mvar], equal to the 63% of the trends reported in Figure 8.26. For example, focusing on the sole bidding zone SUD, the AVC contribution could be 3400 Mvar in 2030, with a remarkable time duration of about 5400 hours. At national level, even if location of plants has to be taken into account, an overall contribution up to 6700 Mvar is obtainable, with a time duration higher than 6 months with limited reductions.

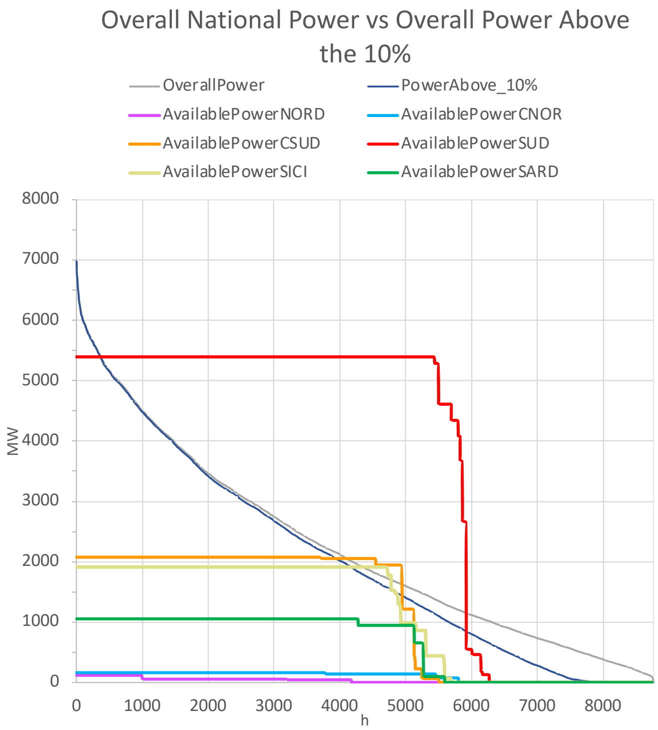


Figure 8.26 For each bidding zone hosting wind farms, duration curve of the overall rated power considering only plants exceeding the AVC threshold (generating coefficient 10%)

8.3.2 WP5 demo cybersecurity scalability

Two classes of KPIs have been defined: the first class is related to NIST 800-53 compliance; the latter is related to the architecture analysis.

Scalability of NIST 800-53 compliance

The assessment of the standard compliance requires as input a value of the targeted SAL for the system under analysis. To support an incremental approach to the cybersecurity maturity level assessment, it is interesting to assess the standard compliance to several (possibly intermediate) SALs.

In each assessment the input SAL influences the category ranks, the number of controls in each category and their relative importance.

A KPI class for the scalability of the standard compliance is defined by (1)

NoR (Req_Cat, SAL) (1)

i.e., Number of standard Requirements, for each requirement category and SAL.

Scalability of the architecture analysis

For the architecture analysis, the KPI classes consider the amount/percentage of assets in each category (2) (3), the size of the infrastructure in terms of amount of industrial plants connected to the high voltage grid (4), and the degree of plant aggregation (5), as defined below.

NoC (Asset_Cat, n_ Asset_Cat) (2)

i.e., Number of Controls, for each asset category and number n of assets in each category.

PoC (Asset_Cat,n_Plant, m_BSP) (3)

i.e., Percentage of Controls, for each asset category, number n of plants and number m of BSP.

NoC (n_Plant | m_BSP) (4)

i.e., Number of Controls, for each number n of plants, given the number m of BSP.

NoC (m_BSP | n_Plant) (5)

i.e., Number of Controls, for each number m of BSP, given the number n of plants.

8.3.2.1 NIST 800-53 compliance

For the cybersecurity assessment of the OSMOSE Italian demo, the NIST 800-53 has been chosen for the standard compliance analysis [9].

The SALs values have been identified by selecting values for confidentiality, integrity and availability considered appropriate for the Demo5 use cases, i.e.:

- Confidentiality: Low;
- Integrity: Medium and High;
- Availability: Medium, High and Very High.

The following four combinations of the triad values have then been considered for the analysis: LMM, LMH, LHH and LMVH. By a comparative analysis of the results achieved for these four SALs (Figure 8.27), we can observe that the control category Access Control always has the highest priority, and the number of controls in this category increases with the required availability level (39 controls for M, 47 for H, 120 for VH).

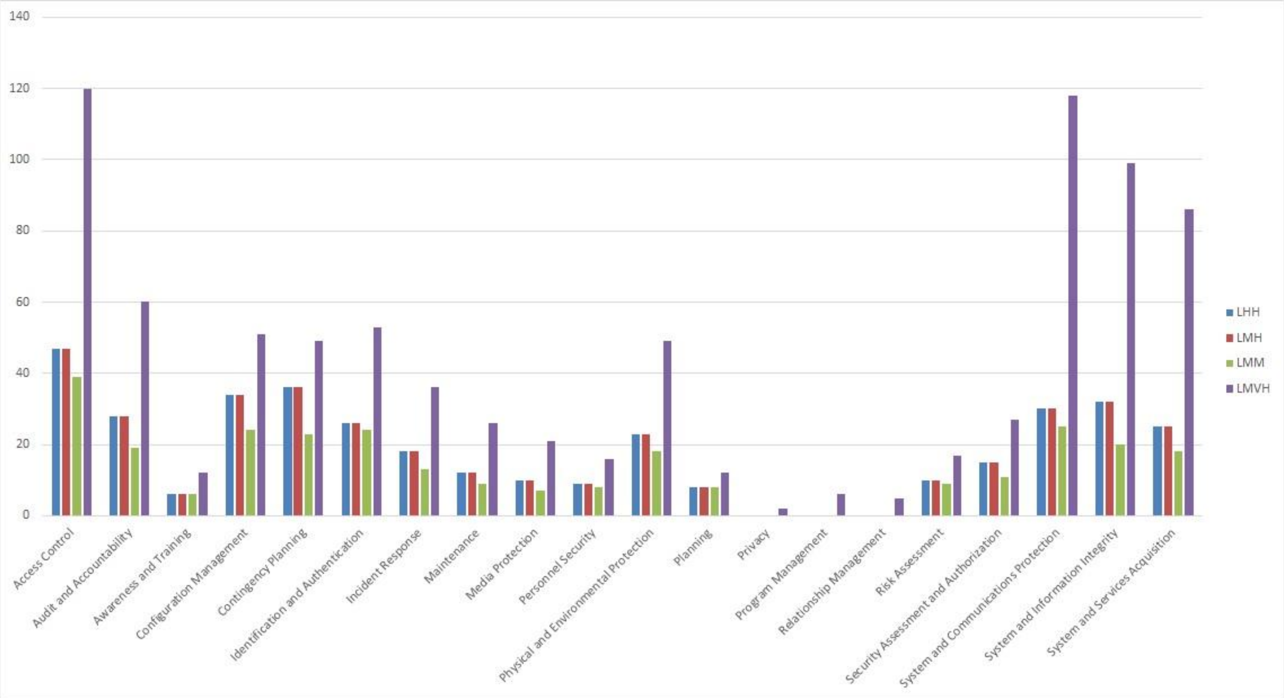


Figure 8.27 NoR (Req_Cat, SAL)

8.3.2.2 Architecture analysis

CSET has been used to assess the security of WP5 Demo ICT infrastructure reported in [1]. The corresponding CSET diagram is reported in Figure 8.28.

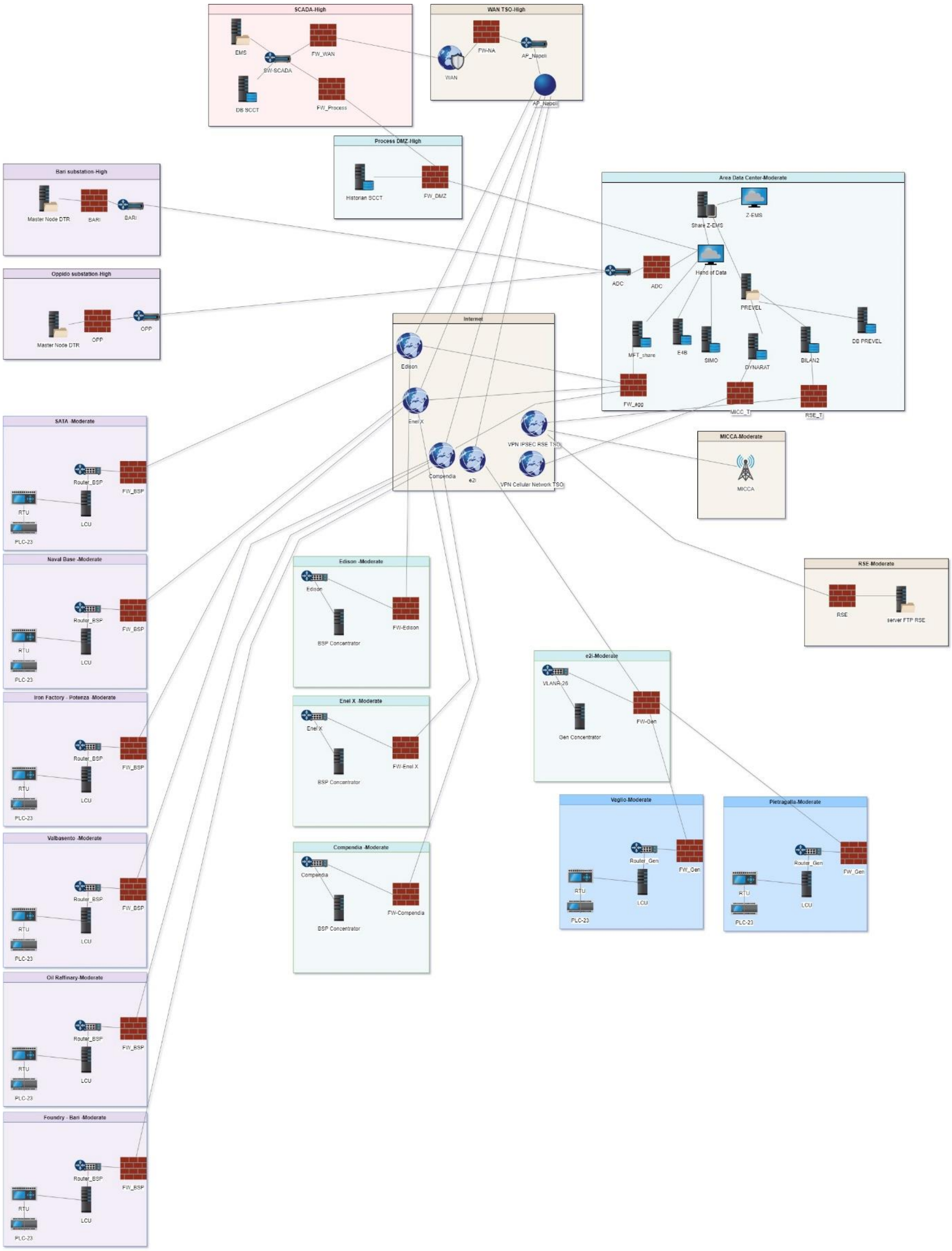


Figure 8.28 - Demo 5 network diagram in CSET

The categories of the architecture assets and their criticality levels influence the priorities of the control categories, as well as the control content and number.

The Demo5 architecture is composed of 94 assets of 14 different categories, as listed in Table 8.65, belonging to 21 areas. In the analysed setup, there are 8 industrial areas with a replicated architecture for the information exchanges from 2 renewable power plants and 6 flexible industrial loads managed by 3 BSPs.

Table 8.65 Asset Inventory

Asset Type	Asset Number
Active Directory	1
Application Server	6
Connector	1
Database Server	8
Firewall	23
Programmable Logic Controller	8
Radio Site	1
Remote Terminal Unit	8
Router	5
Server	12
Virtual Local Area Network Router	12
Virtual Machine Server	2
Virtual Private Network	1
Web	6

<u>Demo5 Scenarios</u>

By focussing the assessment on one industrial plant composed of 5 asset categories and 1 asset per each category, the number of controls is 130.

By including in the assessment all the assets by the TSO and the external actors, the total number of controls is 10678 whose percentage distribution (PoC) and absolute number NoC per asset category are represented in Figure 8.29.

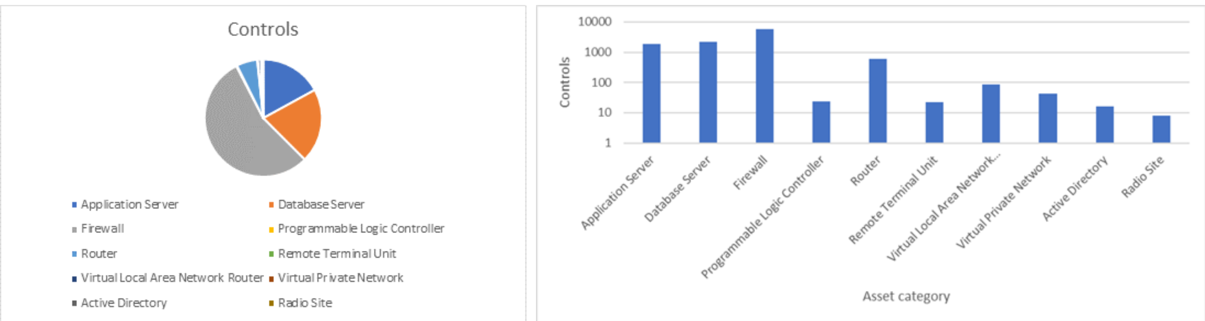


Figure 8.29 – PoC (Asset_Cat,1_Plant, 1_BSP) ; NoC (Asset_Cat,1_Plant, 1_BSP)

More in detail, by addressing the Demo 5 setups, three specific KPIs are considered:

- Edison setup: NoC (1_Plant, 1_BSP);
- Edison and Enel-X setup: NoC (3_Plant, 2_BSP);
- Edison, Enel-X and Compendia setup: NoC (6_Plant, 3_BSP).

In Figure 8.30, the Number of Controls (NoC) for each Demo 5 setup is plotted. With 1 BSP and 1 plant (setup 1) 10678 controls are in place; with 2 BSPs and 3 plants (setup 2) NoC increases to 12011; with 3 BSPs and 6 plants (setup 3) NoC increases to 16064.

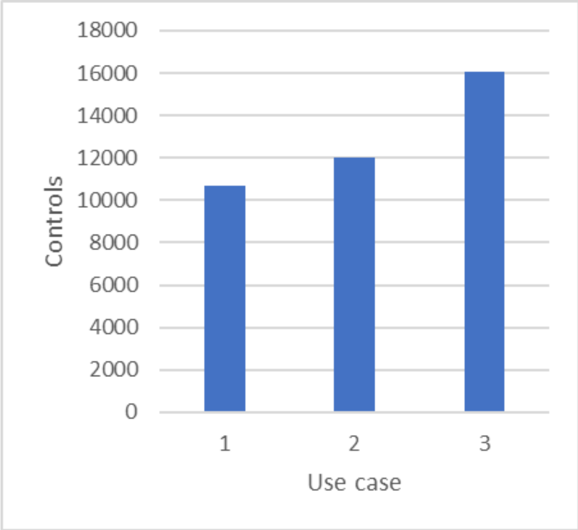


Figure 8.30 - NoC for 3 Demo5 setups

In the following scalability analysis, a variable increasing number of plants (max 100 plants) and a variable increasing number of BSP (max 10) are considered.

Baseline scenario

Considering the special case of industrial plants having the same ICT architecture, i.e., 5 assets of 5 different categories, the number of controls is evaluated varying the number of plants is presented in Figure 8.31.

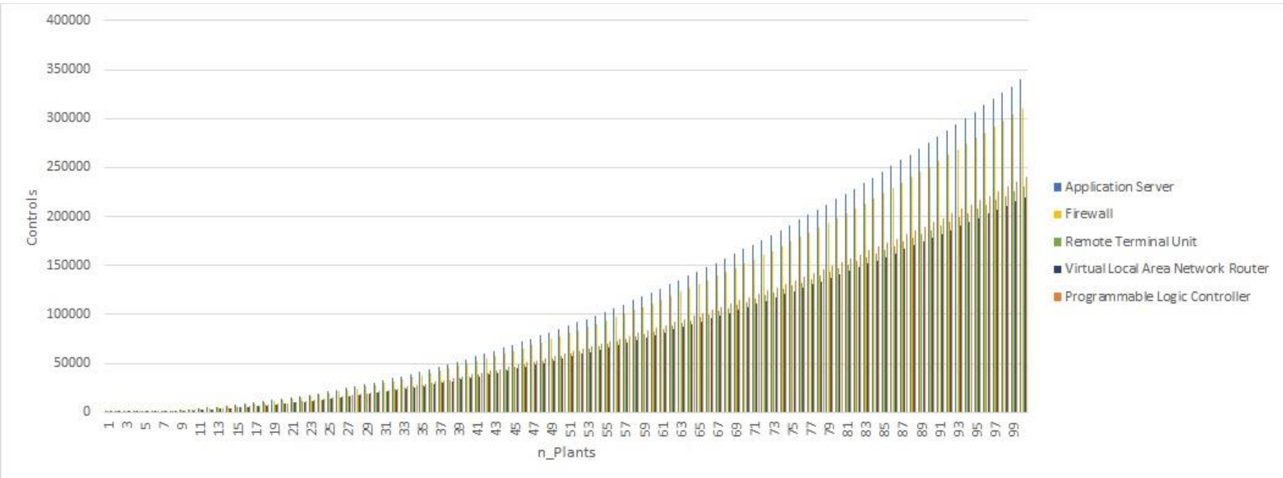


Figure 8.31 – NoC(Asset_Cat, n_Plant)

Scalability with the number of plants

The NoC (n_Plant | m_BSP) KPI estimates the number of controls varying the number of plants (from 1 to 100) considering 4 different scenarios (1, 2, 5 and 10 BSPs): see Figure 8.32.

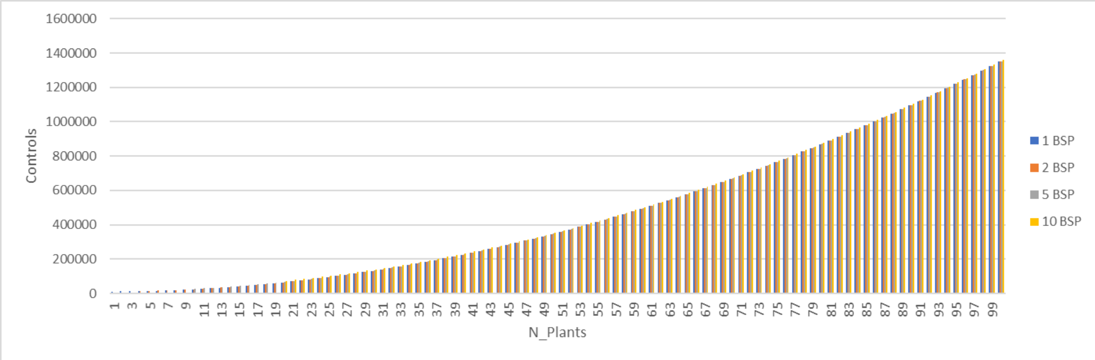


Figure 8.32 - NoC (n_Plant | m_BSP)

For a better visualisation of the values, Figure 8.33 highlights the results, grouping the number with a granularity of 5 plants.

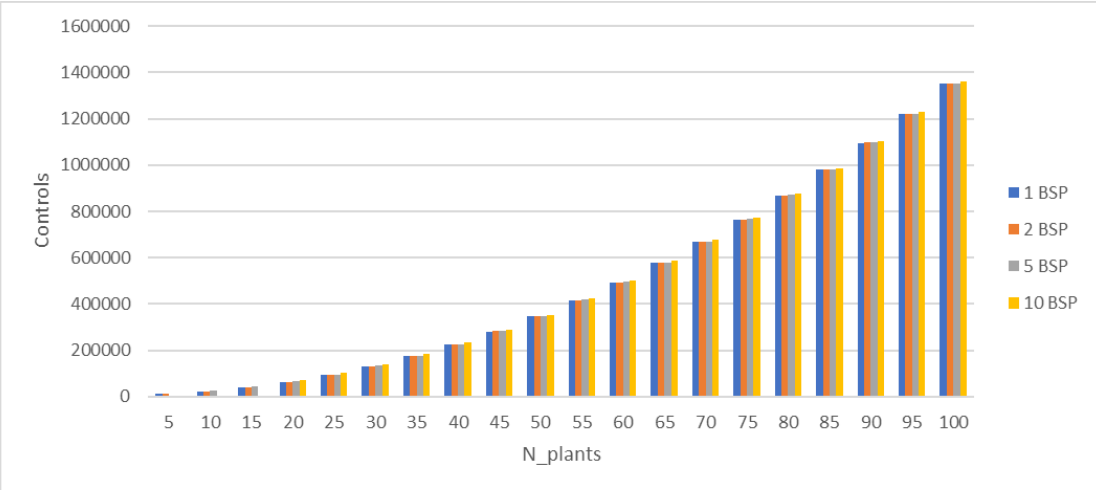


Figure 8.33 - NoC (n_Plant | m_BSP) (granularity 5 plants)

Scalability with the number of BSP

The next addressed KPI evaluates the number of controls varying the number of BSP (from 1 to 10) with 5, 10, 15, 20, 30, 40, 50, 75 and 100 plants. Figure 8.34 reports the results.

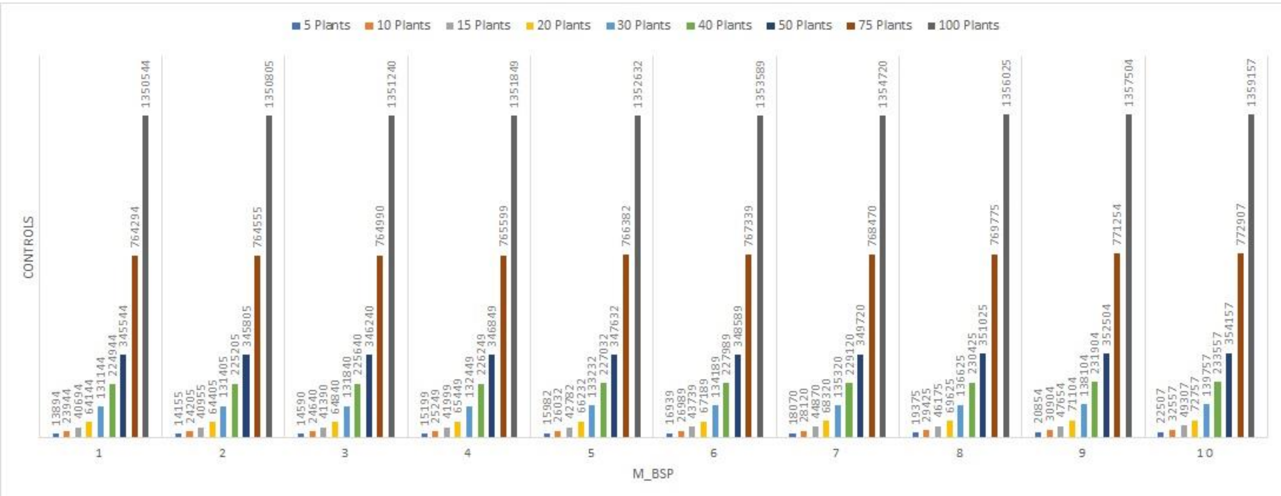


Figure 8.34 - NoC (m_BSP | n_Plant)

By concluding, a quantitative scalability analysis of the cybersecurity assessment methodology of the OSMOSE Italian demo has been performed. Different classes of KPIs have been defined for the

NIST 800-53 compliance analysis and the architecture setups. The KPIs have been evaluated for sample SALs and ICT setups of Demo5, where the increase of the number of requirements and controls can be appreciated by scaling up the SAL, plants and BSP.

8.4 Identified benefits for the Innovative Operation

Fostering system security through an intelligent and more effective control system, maximising the network's capability to manage intermittent generation without adversely affecting the quality of supply, allowing grid users and aggregators to participate in the active management of the network are benefits of the Italian demonstration project of OSMOSE.

Specific benefits have been identified with the questionnaires described in section 7. They are subdivided into direct and derived benefits, which can be economic benefits or others that impact the network operation, the environment and territory, and the social welfare. Such benefits can be summarised as follows.

Direct benefits:

- enhancement in the operation of the system (Z-EMS),
- improvement in congestion management (Z-EMS, DSR, DTR),
- identification of false congestions (DTR, Z-EMS),
- improvement of observability of the distribution system (PREVEL),
- involvement of new stakeholders in the network operation (DSR, SI and AVC from RES),
- Intermittent sources of generation contribution to system security (SI).

Derived benefits (economic benefits):

- reduction of costs for solving congestions,
- reduction of the wind generation curtailment costs (overgeneration costs),
- reduction of dispatching costs,
- final users' energy bill reduction,
- deferral of the investment in new lines (faster implementation),
- deferral of the investment in new lines (benefit for the territory).

Derived benefits (impact on network operation, environment and territory):

- increase of loadability of lines (benefits for the proper network operation),
- reduction of the resort to the balancing services (benefits for the proper network operation),
- RES integration enhancement (benefits for the environment),
- reduction of greenhouse gas emissions (benefits for the environment),
- increase of the social welfare (social benefits).

The deferral or the avoiding of capital expenditures, and the reduction of operational expenditures are the economic benefits achieved with utilization of WP5 pilot technologies by the TSO, green energy producers and final users. In this sense, the DTR reduces the need of generation curtailment and can avoid or postpone the building of new lines by directly impacting the RES-based integration and, consequently, the environment and territory. From the social point of view, all the implemented solutions may reduce the need for balancing services and, thus, the dispatching costs, directly reducing the final user energy bill. Furthermore, third parties as weather forecasting service providers may gain revenues for the provision of the service. Such a revenues are the only direct incomes; the other economic benefits can be considered as avoided costs or cost savings.

Such identified benefits are the same recognised during the OSMOSE WP8 activities that collected the benefits of all the demos included in the project [101]. The answer, given by the WP5 leader (i.e., Terna) to the question "*What are the* ***key benefits****?*" can be summarised in the following points:

1. grid management improvement,
2. possibility to involve new stakeholders in the management of the grids (e.g., the DSR),
3. exploitation of the flexibility services provided by the stakeholders,
4. improved observability and loadability of the grid,
5. enhancement of the RES integration (in particular, wind farms), benefits for both TSO, RES producers and balance service providers,
6. increase of the global social welfare due to a decrease of the cost of energy for the final users (thanks to the reduction of the need for balancing services),
7. at the grid planning stage, postponement of the investment in grid updates,
8. reduction of greenhouse gas emissions (thanks to an increase of RES integration).

The matrix that associates the functionalities and of the already identified benefits is reported in Table 8.66.

Table 8.66 Functionalities-benefits matrix

	UC1					UC2				UC3
			DTR		DSR	AVC		SI		DSR
	Z-EMS + dashboard and HoD	PREVEL	WB DTR	SB DTR	CR	RES +BESS	DFIG	RES +BESS	DFIG	AVC
grid management improvement	●	◕	◕	◕	●	●	●	●	●	●
involvement of new stakeholders	●				●	●	●	●	●	●
flexibility services exploitation	●	◕			●	●	●	●	●	●
improved observability and loadbility	●	●	●	●						
RES integration enhancement	◕	◕	◕	◕	◕	◕	◕	◕	◕	◕
global social welfare	◕		◕	◕	◕	◕	◕	◕	◕	◕
reduction costs of energy bill	◑		◑	◑	◑	◑	◑	◑	◑	◑
deferral investments	◑		◑	◑	◑					◑
reduction of greenhouse gas emissions	◕		◕	◕	◕					◕

● direct benefit

◕ derived benefit

◑ economic derived benefit

8.4.1 Impact of Scalability and Replicability on Costs and Benefits

Figure 8.35 shows an example of mapping the DTR assets on to functionalities, the functionalities on to benefits and the benefits on to monetary values as suggested in [99].

The assets of the sensor based DTR include the sensors (i.e., cooperative network of weather stations and the MICCA sensor for the conductor temperature calibration), the technologies for data transmission, and the software for data management and processing.

The identified direct benefits are the dynamic increase of the transmission capacity and the improved grid operation (as recognised by ENTSO-E [54]) that can be obtained with the Z-EMS that exploits the DTR for reducing the generation curtailment for overgeneration with the identification of false congestions. The direct benefit of DTR can be also measured with the delay or the avoiding of new investments.

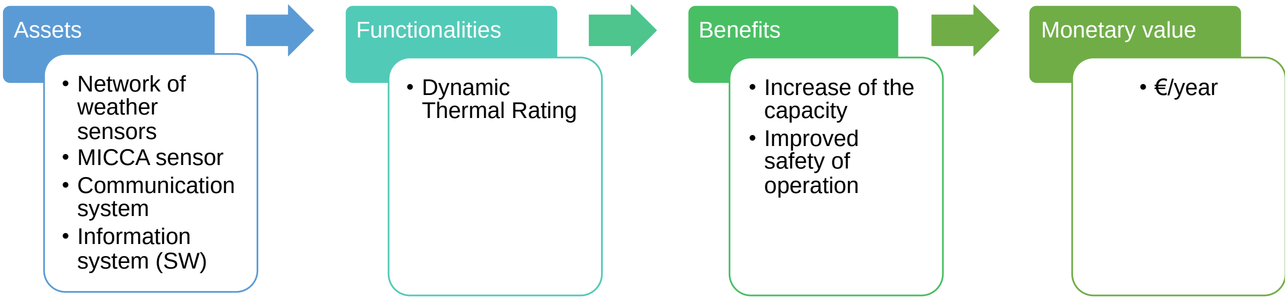


Figure 8.35 Example of mapping applied to the sensor based DTR function

Since the RES generation connected to the Italian transmission network is mostly based on wind, there is a clear correlation about the DTR effects and the risk of overgeneration and the consequent generation curtailment. This means that when the DTR is particularly effective (high wind) is also the time of critical system conditions with high risks of power congestions and need of curtailment (cost of overgeneration) depending on demand. The DTR field tests of the WP5 OSMOSE demo project proved that the dynamic capacity of the monitored lines is greater than the static one for most of the time and the increase reaches significant values (i.e., about 400% of the static rating for 15 min in the sensor-based DTR and about 300% off the static rating in the weather-based DTR) [1].

This means that the DTR is capable to give the systems the same type of benefits that can be obtained with the addition of new transmission capacity, but the costs are order of magnitude smaller. Furthermore, the authorization for the addition of new power capacity takes in many cases a considerable amount of time that must be considered since this constitutes a clear obstacle to the integration of new RES as required by the energy transition goals (indirect benefit). Anyway, it should be noted that Italy falls into the case of countries on which the TSO adopts seasonal thermal limits, which already ensure a corresponding flexible operation, thus reducing the DTR benefit compared to countries that calculate the maximum capacities of OHLs in a conventional way, under worst-case assumptions like maximum ambient temperature and no wind.

The financial CBA for a development planning based on the implementation of pilot DTR considering the benefits that can be obtained with the Z-EMS, or any operational management systems capable to consider the dynamic capacity, gave a positive result compared with the alternative of adding an equivalent transmission capacity even though new transmission capacity is capable to add benefits that the DTR cannot bring (e.g., voltage stability, reduction of energy non supplied, etc.).

This result was predictable, even if it is difficult to quantify the exact economic value of DTR systems since future meteorological conditions and load flows cannot be known with certainty until they occur. A sound estimate can be made by examining the economic impact of congestions. In the US, an economic analysis performed by a regional transmission organization (RTO) by simulating the electricity market demonstrated that the DTR can cut about 4 M$ in a year of congestion costs. Such avoided cost compared with the CAPEX for a commercially available DTR system (about 500 k$) allows a rapid payback period (i.e., approximately two months of operational use) [105]. In Texas, the transmission and distribution operator implemented a DTR system in eight transmission lines by sustaining CAPEX for about 4.8 M$. On average, line congestion costs in Texas are about 250 k$ per line per day. Thus, the payback period is even shorter than the previously described case [106]. In Europe, most of the Countries tested the DTR solution, and all the studies came to the same conclusions. In Germany, the cost of the congestion resolutions was 1 billion € in 2017 and 2018. The cost of congestions was approximately 100 k€ per hour or 4 M€ per day with an average redispatch cost of 23 k€/GWh. The studied case reports that 6 hours redispatch of 200 MW can be instructed in a typical congested day. With the DTR implementation (CAPEX equal to a few thousand of euros per line), such 1200 MWh can be avoided with 27 k€ of savings for this day only [107]. In Spain, a successful case of DTR application by a DSO over several years proved that the time that wind farms were out of service due to an excess of electrical energy generated was heavily reduced (i.e., 4100 h of avoided wind energy curtailment). A supplementary transport of 70.9 GWh of renewable energy was allowed. Considering the yearly medium pool price in Spain, the additional energy transmitted was worth 1.4 M€ with respect to operation using the static rating. In addition, a reduction in CO_2 emissions of 7800 t is obtained, with evident further benefits [108]. In Italy, the DTR solution equipped with sensors that directly measure the conductor temperature (i.e., MICCA sensors) was tested on two lines subjected to local congestions caused by high wind power injection. In such lines, a relevant curtailment reduction of wind production was proved for both lines, even after an increasing of installed wind power. In order to evaluate the DTR benefits in economic terms, it was considered that in case of limitation of production, the wind farms receive a compensation for the difference between the energy that would have been produced (estimation based on the wind data) and the one actually injected. Such not-produced wind energy (Mancata Produzione Eolica - MPE) is valued at the price of the energy market (average prices of 50–70 €/MWh). The reduction in the power input must be balanced by other conventional generation plants on the Ancillary Services Market (MSD), causing an additional cost for the system equal to the upward price offered by the Production Units on this Market (average prices very variable from 70 to 150 €/MWh). In the best cases reported, the savings in the period 2013–2017 in terms of curtailment costs paid by the system (normalized on 2012 production profiles) amounted to about 1 M€/year for each line [109].

All the mentioned cases demonstrated that the reduction of congestion resolution costs is much higher than the cost of implementing the DTR, even if the equipment does not exploit cheaper solutions as the ones proposed within the WP5 OSMOSE demo project.

Despite the positive results of DTR application, a fairer comparison should consider the ENTSO-E's position ([54], section 2.3.3) that highlights that the uncertainties related to the atmospheric conditions along the spans of the monitored lines and the uncertainties in the algorithms used for the calculations heavily affects the results and there is the need models capable to consider uncertainty in final results. Otherwise, the combination of uncertainties and the specificity of the operating conditions that could require the use of enhanced thermal limits can lead to misleading or even false judgements on the effect of DTR. Furthermore, only real-time operation data obtained through pilot installations over long observation periods can provide a good estimate of the effects of DTR implementations and the margins to be adopted for security assessment [54]. The two DTR pilot tests were conducted for enough time but in order to not be influenced by yearly variations tests should be extended on a longer time.

The ENSTO-E considerations must be kept in mind if the CBA is used to appraise the opportunity to replicate the WP5 pilot into a Country. Particularly, it should be considered that a typical CBA gap is represented by the small capacity to deal with uncertainty that is normally considered through sensitivity studies [97]. The sensitivity studies cannot be applied in the case of DTR due to the high level of uncertainties introduced. More sophisticated methodologies must be designed for the project appraisal when DTR competes with infrastructural actions.

Nevertheless, with all caveats and warnings, the tests with the Italian demonstration projects proved that prospective benefit of DTR combined with the Z-EMS can largely compensate the costs for realization and implementation. This result can be replicated to any overhead line with similar characteristics.

Regarding SRA, a distinction has to be made between SB-DTR and WB-DTR to analyse the impact on costs when applied on a large scale. For the WB-DTR the scale up or replication requires the availability of weather forecast with a granular information on a country scale that means the significant increasing of the related service costs. Anyway, the service provider of weather forecast can benefit of scale economy and the impact of scaling up to a wider area is expected to be positive (reduction) on the cost of the single service.

For the SB-DTR, the impact of scaling up on costs depends on the need of sensors (i.e., 20 k€ for the MICCA sensors and 3-4 k€ for the weather stations, Table 12.2). One MICCA sensor is needed per line, but it is used to calibrate the algorithm only. Then, the same MICCA sensor could be moved from one line to another when the calibration period ends with a negligible impact in case of scaling-up and replication. The number of weather stations to be positioned along the monitored lines for creating the cooperative network depends on the orography of the territory and cannot be exactly determined in advance, but the OSMOSE pilot demonstrators are a good representation of an average case that gives a clear indication of the expected number of weather stations. The scale up and the replication, since the demonstration projects used commercial sensors only, will lead to a reduction of costs thanks to the high volumes of sensors involved. Thus, the scalability both in density and in size is associated with a reduction of costs (i.e., the CAPEX grows less than proportionally to the number of purchased sensors). The software developed in the project for SR-DTR and WB-DTR as well the Z-EMS is ready for deployment and no further developments are necessary. The software can be installed in as many primary substation servers as one wants to equip with the DTR (the limitation of 100 controlled sensors per line at maximum is even too big for realistic cases). In conclusion, for both SR-DTR and WB-DTR and their use with Z-EMS, scaling-up and replication lead to the reduction of capital expenditures (sensors) and operational expenditures (weather forecasts) and do not need any R&D activity for new software. The experimental tests did not allow to assess the needed O&M costs even though they can be like those for any network of distributed sensors.

Thus, by considering that the benefits can increase even proportionally by scaling up the DTR implementation and the costs, on the contrary, raises less than proportionally with the size, the financial DTR CBA can lead to positive results. This is particularly true if the output-based incentivising mechanisms promoted by the Italian Regulator [29] is considered. The Italian Regulation applied to non-capital-intensive investments, such as in the case of DTR, gives a maximum admissible incentive equal to the sustained capital expenditure (with a 10 million Euros cap) for each grid section or subsection. In the case at hand, the proposed DTR solutions are far less expensive than the maximum cap making the DTR fully incentivised.

9 Results, recommendations, rules, and barriers

In this section the results of the SRA are discussed with the aim of formulating recommendations and identifying barriers in the scalability and replicability of the demo project of the OSMOSE WP5.

Each use case is dealt with separately and discussed in view of scalability and replicability.

9.1 UC1 discussion

The UC1 of the demo project OSMOSE WP5 revolves around the Zonal-Energy Management System (Z-EMS) that aims at detecting and solving in advance congestions that may happen in the sub-transmission grid. Its role is to perform the optimisation of the available resources based on the input data from the field. The input data come from the other tools/applications of the demo project of OSMOSE WP5, namely PREVEL and DTR (within the UC1) and include the involvement of end-user facilities (UC1 and UC3) called to provide services of flexibility.

Such an architecture can properly run by means of the Hand of Data, which assumes a crucial role in the whole operation of the implementation because it assures the input data processing, the communication between databases, measurements, results of processes (i.e., from DTR, PREVEL), and manage the results of the Z-EMS itself. Furthermore, with the graphical interface provided by the dashboard, the Z-EMS user (i.e., the TSO operator) can be warned of the detected congestions, can manage the proposed solutions that can be no-costly as DTR or can involve the offers from the available BSPs, and finally allows to monitor the state of the observed network (e.g., the loadability of the lines).

Since the UC1 was developed by exploiting several functionalities, all of them were analysed separately in view of scalability and replicability. Table 9.1 and Table 9.2 report the resulting indicators obtained by applying the proposed methodology for scalability and replicability analyses to all the UC1 functionalities, respectively.

Table 9.1 UC1- Resulting scalability indicators

	UC1						
					DTR		DSR
	Z-EMS	**DASHBOARD**	**HoD**	**PREVEL**	**WB DTR**	**SB DTR**	**CR**
Technical	70.0%	69.5%	73.0%	54.5%	76.0%	68.5%	73.0%
Economics	60.0%	68.8%	68.8%	100.0%	100.0%	80.0%	71.3%
Acceptance	80.0%	80.0%	80.0%	81.8%	80.0%	80.0%	80.0%
TOTAL	**69.3%**	**70.2%**	**72.5%**	**69.9%**	**82.4%**	**73.1%**	**73.7%**

Table 9.2 UC1-Resulting replicability indicators

	UC1						
					DTR		DSR
	Z-EMS	**DASHBOARD**	**HoD**	**PREVEL**	**WB DTR**	**SB DTR**	**CR**
Technical	67.4%	74.1%	60.0%	86.7%	80.0%	80.0%	65.9%
Economics	89.1%	80.0%	80.0%	69.1%	89.1%	78.2%	60.0%
Regulatory	100.0%	80.0%	80.0%	92.0%	80.0%	68.0%	60.0%
TOTAL	**78.6%**	**76.8%**	**70.8%**	**83.1%**	**82.6%**	**76.4%**	**62.7%**

From scalability and replicability points of view, by applying the analyses proposed in this report, all the UC1 functions obtained good performance indicators in all the considered areas (Table 9.1 and Table 9.2). The analyses generated broadly positive results: all the TOTAL indicators overcome 50 %, and most of them have proved that the proposed functions are prone to be scaled up and replicated.

Z-EMS

Concerning the Z-EMS, its characteristics in terms of scalability and replicability are generally significant: its total score for scalability is around 69% (Table 9.1) and for replicability is around 79 5 (Table 9.2).

With reference to technical characteristics (scored as 70%), the main limitation that can obstacle the scalability of the solution can be due to the size of the grid and the number of components (DTR and controllable loads) that may affect the computation time. The actual performance seems to be short enough for the purposes (i.e., it is around 2 min 30 s for managing 1600 nodes, 4000 lines, 7 DTR installed, and 3 controllable loads), but it can become too long if the data to be processed by the Z-EMS are delayed in being available and, indeed, the results of Z-EMS are shown late in the dashboard. Concerning only the time taken by the three Z-EMS tasks (i.e., the check of the data quality, the optimisation, and the output arrangement), the limitation can be overcome by upgrading the HW resources to speed up such three processes. The data quality is checked before running the model, and hence the user could identify if the execution failed. Regarding the potential evolution, it is worth noticing that since the Z-EMS is being tested and validated in a real operational environment, at the end of the project, its TLR is 8. Nevertheless, some rooms for improvement could be envisaged. For instance, considering the reactive power within the optimal power flow calculation and the variations of the network configuration can help improve the result accuracy. Furthermore, since the assumption that the network topology remains unchanged for the 12 next time step is often untrue, the prediction of the network configuration can further improve the result accuracy.

Observing the Z-EMS economic area of scalability (scored as 60%), the potential need for more HW resources can be a barrier that may limit the use of the solution on larger portions of the grid. Still, it is easy to be put into practice. Maybe to properly decide to what extent the project is scalable by maintaining its economic viability, a business case should be addressed for estimating the expected number of congestions per year and avoiding congestion management costs. However, even if the demonstration phase results are generally good, the most calculated KPIs demonstrate better performances of the Z-EMS in the extended area than in the demo one, by encouraging the scaling up of the solution.

Regarding the replicability technical characteristics (scored around 67%), the Z-EMS uses the open-source coding system Python and the commonly used optimization suite CPLEX and, thus, its code is easily replicable in different operative systems (e.g., Windows or Linux). The algorithm is perfectly plug and play. It can adapt its operation and interaction to different settings, without having to major changes in the code, provided that the input data are in the correct format. The interoperability of the Z-EMS may present some barriers, mainly due to the data format. Different data formats require additional pieces of code to make the use of the Z-EMS possible with different data formats.

The economics of the replicability (scored around 89%) are indeed interesting. In fact, the benefits may be high in case of high dispatching charges (i.e., where thermoelectric units are used for solving congestions) or when the generation curtailment is frequent.

Concerning the regulatory aspects and the acceptance from the stakeholders, both for scalability (scored as 80%) and for replicability (scored as 100%), no barriers have been detected for the implementation of the Z-EMS. The acceptance of the Z-EMS that, on the one hand, reduces the number of grid congestions by using the DTR technology and, on the other hand, involves the end-users by exploiting the flexibility of their controllable loads, is self-evident because its use may help to integrate more RES in the network, and can defer the investments in new lines (by identifying false congestions that require the current assets to be substituted).

Dashboard and Hand of Data

Both the Dashboard and the Hand of data, analysed with the approach described in this report, gained good rating in terms of scalability and replicability points of view (i.e., the total scores are around or even greater than 70%, with a maximum of 80% as reported in Table 9.1 and Table 9.2).

With reference to the technical scalability dimensions, the two solutions (scored 70 % and 73%, respectively) are modular because they allow adding more data sources as shared folders, thanks to the fact that the data exchange is based on standard protocols. Even if their TRL at the end of the project reached 7 (starting from TLR 0), since the dashboard and the HoD are running on the operational environment hosted by the TSO, their response time might be a barrier in case of an increase in the number of sources and file sizes. This is because the HoD is responsible for the data orchestration process by scheduling and managing the timing of the overall demo execution, and the dashboard interacts with the HoD for making available the data to the Z-EMS user. Thus, their response time may affect the proper operation of the Z-EMS (e.g., if the dashboard does not update an aggregator offer), and for these reasons, the software integration must be carried out accurately. An extension of the HoD functionalities may be required to handle new data, as well as an increase of the HW resources can be required.

Regarding the scalability economic area, the two solutions (both scored around 69%) highlighted that an increase of the file sizes would imply large disk space, with an increase of the related costs. For the acceptance from the stakeholders (both scored as 80%), no barriers have been detected for the implementation of the Dashboard and the HoD.

In terms of replicability technical dimensions (Table 9.2), the dashboard and the HoD (scored both >70%) rely upon communication standard protocols. Even if they have been developed to meet the Italian TSO requirements (as the dashboard) and adapted to the grid code considered in the use case application (as the HoD), the adopted technologies allow being deployed in different environments. Such adaptation can be very easy and without additional investment for the dashboard. While, for the HoD, the adaptation could need the check of the compliance with other grid codes, possible new configuration settings and some feature extensions for meeting specific requirements arising from the new context. However, again a barrier may appear when different data formats are used. Hence, in general, the technical characteristics do not present other barriers to replicability.

The economic factors (scored as 80%) do not directly influence the success of the replication of the Dashboard and the HoD as single components. Finally, within the regulatory aspects (scored as 80%), no issues regarding the acceptance are detected, and the dashboard and the HoD can be exported to other systems to satisfy the TSO requirements.

PREVEL

The forecasting tool PREVEL contributes to the congestion management executed by the Z-EMS by improving the observability of the distribution systems and consequently making less uncertain the power exchange through the transformers of the primary substations. No changes in the expected profiles at the TSO/DSO interfaces mean to bring back the power system management to the era before massive RES and DG diffusion when the TSOs were able to foresee the demand of the distribution systems with a very low level of uncertainty. A reliable forecast could provide more efficient management of flexibility and facilitate a reduction in the primary reserve, with benefits for the whole community. Indeed, a smaller error in the forecast of the residual load demand can reduce the need for balancing services and, consequently, the ancillary service costs, related to the significant role of RES connected to the Distribution. Such costs impact directly on the energy bill of the end-users.

From scalability and replicability points of view, by applying the analyses proposed in this report, the PREVEL tool obtained good performance indicators in all the considered areas (Table 9.1 and Table 9.2). All the indicators overcome 50 %, and the solution seems to be perfectly scalable in economic terms and quite perfectly replicable in other countries with different regulatory frameworks (it gains respectively 100% and 92 % in such area indicators). The technical scalability of the solution might be theoretically assured by the software architecture that is perfectly modular since it exploits parallel computing. However, some issues limit the scalability of the PREVEL tool. The limitations are firstly due to the hardware because RAM and the number of processors directly impact the execution time. Still, since the easiness of increasing such HW resources, such limitation can be simply overcome. The stronger limitations are due to the adaptability of the algorithm to new configuration/new loads and to the interaction between the tool and the databases where are collected the input data. In fact, the necessity of updating the data stored in the databases when new loads (to be forecasted) become active, the need to train the algorithm to deal with the new loads and the communication with the databases are critical issues that limit the technical scalability of the solution. Indeed, the needed check of the system status by a human operator for avoiding uncontrolled stops can become a serious problem if the amount of data processed increases. Fewer limitations can be encountered from the technical replicability point of view since the software is written exploiting open-source products, and the developed mathematical formulation used algorithms widely investigated in Literature for load forecasting (i.e., random forest and the analog ensemble). Indeed, the SW is ideally replicable if the input data are in the same format as the case studied.

No barriers can be envisaged in the acceptance and regulatory issue scalability and replicability dimensions. It is worth noticing that forecasting tools like PREVEL able to estimate the power profiles at the TSO/DSO interfaces reduces the uncertainty relevant to the part of the power system, the Distribution, that is the least observable. Despite the forecasting is an estimation and, thus, less accurate than a measure, it can be a cheap option that should be taken into account for gaining good knowledge about the distribution system. Nowadays, TSOs use the persistence approach for estimating the power profiles at the TSO/DSO interfaces, but such an approach has proved to be effective only for the next half hour. With the opening of markets of flexibility is crucial to know in advance the electrical behaviour of customers and production plants, and 30 minutes are not enough. Indeed, the need for real-time generation/load forecast is a general requirement, independent by the country. Regulation in countries different from Italy can include rules that improve the observability of the distribution system, and the forecasting PREVEL can be facilitated in its task.

DTR

The dynamic thermal rating (DTR) is used in UC1 to increase the power supply's security and reduce the curtailment of renewable generation. Some key innovations of the two proposed implementations (i.e., the weather-based and the sensor-based DTR) can be recognised. The SB-DTR exploits the adaptivity of the cooperative sensor network, which can relieve the HW complexity of direct conductor temperature measurements by allowing its estimation by built-in mathematical models and low-cost environmental sensors. Such an adaptivity improves the solution robustness to parameters drift and time-variant phenomena affecting the conductor thermal dynamic. Furthermore, although such a feature can be a limitation from scalability and replicability points of view, as detailed in what follows, the radio-based communication between the sensors allows a dense spatial sampling without requiring the deployment of a Wide Area Network (e.g., GSM). By implementing both the thermal and the mechanical model of the lines, the WB-DTR allows calculating the maximum tolerable current that complies with the thermal limit and the maximum permissible sag span by span. This is particularly innovative because only models using a single equivalent span have been available in the literature so far. The implemented model considers the suspension insulator strings placed between two dead-end towers free of moving.

The two proposed implementations have been analysed from the scalability and replicability points of view.

The scalability and the replicability indicators of both the solutions are very high (from a minimum of about 73 % to a maximum of over 82%, in Table 9.1). This highlights that no significant barriers can be detected to the adoption of the DTR in more large size networks (scalability in size), in a bigger number of observed lines (scalability in density), and/or in other contexts (replicability). Such a result was predictable since the DTR adoption, although it cannot be considered an effective alternative of the reinforcement or the building of new lines, once implemented, can be a non-costly option for solving congestions. As mentioned in sections 2.2.3 and 8.4 of this report, the benefits of considering thermal ratings greater than the static ones for the lines, especially the aged ones (i.e., built 30-40 years ago) and/or the ones that are influenced by wind farm productions is recognised by Regulators and TSOs. The benefits are evident. Disregarding the obvious direct increase of loadability of lines, the enhancement in the exploitation of the existing assets, the reduction of the needs of ancillary services, with consequent reduction of the dispatching costs, the increase of RES integration in the network, due to the reduction of their production curtailment, are some of the benefits achievable with the DTR.

The scalability technical dimensions reach considerable scores (76.0 % and 68.5% for the WB-DTR and the SB-DTR, respectively). Both the solutions are perfectly modular and are scalable to many overhead lines one wants to observe. The only actual and mandatory condition is that all the input data, the structural ones, and the variable ones, from the field (i.e., from the cooperative network of sensors to the master node of the SB-DTR) or from the forecasting service to the processor that implements the WB-DTR, are continuously provided. Such a condition strongly depends on the communication systems based on TCP/IP protocols for the interaction with PREVEL tool and the databases of the TSO and, in the case of DTR-SB, via radio communication between the network of sensors and master node. Since the computation time is very short for both the applications and the SW codes are ready to be scaled-up, the main risk in the increase of monitored lines is that the interactions between tools fail or the communication latency between master node and sensors takes a too long time. The reached TLR (7) ensures the scalability of both solutions, even if potential improvement can be envisaged in advancement in ICT (i.e., the diffusion of 5G).

From an economic point of view, it is trivial noticing that the WB-DTR is cheaper than the SB-DTR because scaling up the latter implies purchasing and installing MICCA sensors for calibration and new weather stations as many are necessary to cover the territory on which the observed lines extend. Nevertheless, both the solutions gained really high scores in the economic dimensions (100 % and 80 % for the WB-DTR and the SB-DTR, respectively) because in both cases, the economies of scale can be obtained by stipulating favourable contracts with third parties for the forecasting service in large areas and by getting discounted prices for buying a big number of weather stations. In addition, the installation of many sensors makes sense only for limited zones, for instance, in the spans where there are the most critical conditions, or the orography is complex. Thus, only the cost of the MICCA sensors may partially limit the SB-DTR scalability. On the other hand, the profitability of the adoption of the DTR seems self-evident since the costs grow less than the size of the scaled implementation, and the benefits can only increase with the number of observed lines (as reported in 8.4).

Regarding the impact of regulation and the acceptance of the stakeholders in the deployment of the DTR both the solutions gained indicators equal to 80% (Table 9.1).

Two issues arose from the analyses described in this report about the regulatory framework. The first is related to the radio communication of the SB-DTR that has to be compliant with the rules of the radio frequency award. Still, it is very improbable that the award of the needed radio frequencies is not granted. The second is worthy of being investigated. It is relevant to an output-based incentivising mechanism recently approved by the Italian Regulator that can also be applied to investments characterised by a low investment intensity, such as in the case of DTR. In order to promote investments in innovative solutions, the Regulator extended the maximum admissible incentive to the maximum between the investment capital cost and a 10 million Euros cap for each grid section or subsection. This possibility could modify the cost-benefit ratio by heavily reducing the CAPEX.

Concerning the consent from the stakeholders, no barriers have been identified. The involvement of the social partners may favour the deployment of the DTR solution. With this perspective, it should be emphasised/stressed that the DTR can defer building a new line (with an immediate benefit for the territory) and reduce the generation curtailment of the wind power plants (with an advantage for the producers but also with an enhancement of the RES integration).

The general considerations about the replicability of the two DTR applications are the same as the ones made for their scalability. Some indicators are even improved, like the ones relevant to the technical dimensions (i.e., 80% vs 76% and vs 68.5 %, for the WB- DTR and SB-DTR, respectively, in Table 9.2). This is because both are compliant with standard models (i.e., CIGRE and IEEE), are perfectly compatible and interoperable with any grid codes, and their SW applications are plug and play (or, better, cut and paste). Network configuration, radial or meshed, or voltage levels do not impact the replicability of the solutions in other contexts. The only impacting issue is the orography of the territory for the SB-DTR because the quality of the radio communications between the weather sensors may be affected by it. Still, such limitation can be overcome by guaranteeing a reliable network (compliant with the N-1 criterion).

From the economic point of view, the indicators are slightly smaller than the corresponding ones relevant to the same area scalability dimensions (about 89 % vs 100% and 78 % vs 80 % %, for the WB- DTR and SB-DTR, respectively), but no significant barriers are envisaged. The same can be said about the acceptance and the regulatory issues that are not critical. The reduction of the indicator of the SB-DTR is due to the only improbable barrier related to the rules for the award of radio frequencies in other countries.

DSR

In the framework of UC1, the Demand Side Response (DSR) functionality for Congestion Resolutions (CR) has involved 5 industrial plants as third parties, HITACH-ABB who designed and provided the necessary hardware and Compendia, Edison and Enel-X, who served as Balancing Services Providers (BSP) through their aggregators' platforms. CR tests were aimed to provide an energy exchange with the grid to solve the congestions starting from regulation orders (BDE) sent by Terna's territorial control room to the BSPs. BDE executions were based on the communication of: i) a specific activation time (minimum advance by which the bid must be called); ii) a baseline (prediction of power exchange with the grid during the day) and iii) a minimum and maximum amount of available regulating power.

By applying the analyses proposed in this report, DSR has shown good opportunities for scalability (Table 9.1); an overall score of 73.7% demonstrates that no specific barriers have been encountered in all the three areas: technical (73%), economical (80%) and of acceptance (80%). Considering the scalability technical dimensions, the HW solution is modular, and the aggregation platform is easily scalable. The reached TLR ensures the scalability of the solution with reference to the aggregator side: it could be expected that more sophisticated logics and tools have to be developed in the short/medium term for enabling more automation. The potential critical aspects can be related to the need of:

- a reliable prediction of the baseline of the plants where the low incidence of the loads used on the total consumption of the site can affect the quality of the service provided;
- an automated control system of the modulated load which should be remotely controllable by the BSPs.

From an economic point of view the evaluation of the profitability of the solution should consider the remuneration mechanism of the aggregators that it has not been implemented in the demo project. However, the opening of markets of flexibility can be the actual opportunity for the aggregators, and no barriers, but instead, rules for promoting the involvement of the end-users in the operation of the system can be envisaged.

Concerning the replicability of the solution, the overall score is 62.7% which evidences the presence of a few possible barriers which require more verifications and analyses. technical, economic and regulatory areas scored 65.9%, 60% and 60%, respectively (Table 9.2). The main potential barriers encountered in replicability are related to the need for specific economic analyses depending on local territorial factors, economic remuneration of the service and the complexity of the different territorial and market scenarios. Moreover, set points response times and accuracy requirements can be conditioned by national and regional regulation rules.

The main recommendations for the DSR scalability and replicability for CR purposes are as follow:

- grid codes and regulations of the countries where this solution will be used should be harmonized at the European level;
- cost-benefit analyses aimed to demonstrate the profitability of the solution in terms of remuneration for the service provided, versus the technological investments necessary to

fully comply with the TSO regulations and with the economic losses related to the power modulations should be performed;

- industrial partners offering this service should have a predefined set of controllable loads compatible with the ordinary plant processes and "natively enabled" through a standardized set of specifications, to provide the service automatically and remotely.

9.2 UC2 discussion

Table 9.3 and Table 9.4 report the resulting indicators, obtained by applying the proposed methodology for scalability and replicability analyses to the UC2 functionalities, respectively.

Table 9.3 UC2-Resulting scalability indicators

	UC2			
	AVC		SI	
	RES +BESS	DFIG	RES +BESS	DFIG
Technical	85.0%	77.0%	73.5%	47.5%
Economics	40.0%	71.3%	51.3%	60.0%
Acceptance	49.1%	49.1%	40.0%	40.0%
TOTAL	**68.4%**	**71.0%**	**62.7%**	**49.3%**

Table 9.4 UC2-Resulting replicability indicators

	UC2			
	AVC		SI	
	RES +BESS	DFIG	RES +BESS	DFIG
Technical	72.6%	51.9%	72.6%	45.9%
Economics	40.0%	50.9%	40.0%	50.9%
Regulatory	68.0%	60.0%	48.0%	40.0%
TOTAL	**62.2%**	**53.7%**	**57.1%**	**45.8%**

The contribution of renewable plants to AVC is achievable both considering WTs and BESSs. In the latter case, the solution showed good performances and confirmed to be easily scalable to larger sizes (overall score 68.4%) and replicated in other sites (overall score 62.2%), both at national and international level. One of the main features of BESS in AVC is the ability of providing voltage support even in the case the primary source is limited or absent, according to the capability area of the BESS inverter. To provide reactive power according to the present grid code, the BESS converter has to be adequately sized in term of exchangeable reactive power (both inductive and capacitive, up to 35% of the wind plant rated power). If the BESS inverter does not cover the entire wind plant capability, WTs are required to contribute to control the reactive power exchange at the POD, and adequate specifications in terms of dynamic response and accuracy must be respected (considering the entire time interval between TSO control signal transmission and wind farm response at the POD). Additional aging of main components to provide AVC seems negligible. Developed logics applied to the BESS could be replicated also to storage systems combined with other renewable plants (e.g., to BESS installed to improve the predictability of photovoltaic plants) or, in general, to storage units installed independently from a renewable generation plant. These evaluations imply high final scores for technical areas both in terms of scalability (85.0%) and replicability (72.6%).

A regulatory evolution in terms of AVC technical requirements and remuneration could allow both a standardization procedure and an economic interest of investors in providing the service through a BESS. An effective cost benefit analysis is difficult at the moment since no remuneration schemes exist, then economic areas reach 40.0% for both scalability and replicability analyses. Furthermore, the BESS has the ability of providing contemporarily several ancillary services to both the main network and the generation plant itself, and a part of these could be remunerated independently from providing AVC. This could contribute in justify the BESS capital cost, since a storage unit is rarely installed to supply a single service.

Oppositely, providing AVC by suitably controlling WTs can make available the plant capability curve with minor additional costs and without remarkable limitations on plant operation. This reflects in higher evaluations in economic areas, both for scalability (71.3%) and replicability (50.9%). Field tests demonstrated the ability of the system in regulating reactive power and allowed the WT manufacturer to solve some issues in the turbine controller. Dynamic response has to be improved both on the signal processing point of view (by adopting dedicated hardware and communication channels/protocols able to evaluate and transmit the WT set points in a shorter time) and in terms of dynamic response of WTs (tested machines are compliant to the previous grid code according to their commissioning date). These issues penalised this solution in comparison with the BESS in technical areas (77.0% in scalability, 51.9% in replicability). In this solution, primary source availability is required above a minimum threshold (electric production higher than 10-20% of the WT rated power) to make WTs able to supply AVC. In the future, different controllers applied to WT converters (with size equal to about 30% of WT rated power in the case of DFIG, and 100% of the WT rated power in the case of full converter machines) could make available the reactive power support even in the absence of wind.

Differently from adding a BESS downstream the wind farm POD, the development of WTs to make them able to provide AVC requires the strong engagement of WT manufactures, since implementing modifications on machine converters and controls could impact on certification and warranties of WTs. Therefore, replicability on existing plants is quite difficult. Availability of WT manufactures could be obtained by imposing specifications (especially in countries where the wind market is relevant) or by introducing remuneration schemes that could make these innovative WTs more interesting from the economic investors point of view.

BESS demonstrated to be a feasible solution for providing SI, with scalability and replicability overall score of 62.7% and 57.1%, respectively. Its stabilizing contribution is easily configurable by acting on the relative controller, without impacting on WT controllers that are usually property of WT manufacturers. Technical scores are 73.5% in scalability and 72.6% in replicability. The developed solution is at the prototypal level and requires to be standardized and industrialized to reach the commercial stage. BESS performances (including both batteries and inverters) demonstrated to be adequate to the SI specifications in terms of response time and accuracy, even if an improvement on the control system to make it able to correctly identify the real events in which the SI contribution is required has to be investigated before implementing the technical solution on large scale. In details, the ROCOF measure and the activations thresholds in terms of frequency deviation and ROCOF require to be studied according to the network main characteristics.

As for AVC, BESS and relative controllers could be easily scaled-up by adding components in a modular architecture, whereas replicability could be extended to other renewable plants or to storage units installed independently from generation plants. At the main system level, BESS is able to supply SI independently from the primary source availability, according to the provision of other services that could impact on its operating conditions (e.g., in terms of internal state of charge).

Barriers on the economic area are similar with those discussed about providing AVC and are confirmed by evaluations in economic areas (51.3% for scalability, 40.0% for replicability). Since SI is not included in present grid code and, consequently, the service is not remunerated, a credible cost benefit analysis cannot be concluded. In terms of compatibility between providing SI and other ancillary services obtainable through a BESS, SI falls in the range of power-intensive use of storage devices. Then, in general, it does not remarkably interfere with other energy-intensive uses of BESSs.

Developing SI onboard on WTs could allow a surplus of injected power up to 10% of the WT rated power in the case of network under-frequency, according to laboratory tests applied to a DFIG WT (similar research could investigated the contribution made available by full converter WTs). The contribution is available only if the WT is operating above a minimum admitted activation threshold (reasonably 30% of the WT rated power) to avoid instability risks caused by an excessive reduction of the rotor speed. Mechanical stress, time duration of the contribution and other parameters are similar with those prescribed by some present grid codes. This suggests that providing SI at the WT level could be obtainable with limited developments of converters and controllers, which could mean with reasonable additional capital costs (scores in scalability and replicability economic areas are 60.0% and 50.9%, respectively). A specific development is required on the frequency/ROCOF measurement chain to correctly identify the events when the SI contribution is required, as well as dynamic response of WTs is required to be tested on-field, then evaluations on technical areas result 47.5% (scalability) and 45.9% (replicability). Analogously to AVC, providing the service by implementing innovative algorithms in the WT implies a strong participation of WT manufacturers that are required to make available on the market machines with this feature. The contribution is suggested to be configurable in admitted ranges in order to both maximize the SI benefits according to the main grid characteristics (type, frequency and entities of network perturbations) and preserve WTs from additional aging in the case of connection to weak networks.

9.3 UC3 discussion

Table 9.5 reports the resulting indicators, obtained by applying the proposed methodology for scalability and replicability analyses to the UC3 implemented functionality.

Table 9.5 UC3- Resulting indicators

	Scalability
	DSR
	AVC
Technical	61.0%
Economics	80.0%
Acceptance	80.0%
TOTAL	**68.7%**

	Replicability
	DSR
	AVC
Technical	65.9%
Economics	60.0%
Regulatory	60.0%
TOTAL	**62.7%**

In the framework of UC3, the Demand Side Response (DSR) functionality for Automatic Voltage Control (AVC) was carried out at the industrial park involved in the project, with the partner Compendia serving as BSP. The solution was performed manually, being the realised demo not able to directly convert the input set-point values received by Terna into control variables at the individuated local resources. The tests carried out were used to identify the potentialities of MV local resources with reference to: voltage drops on MV and HV grids, amount of reactive power and response time.

The most relevant results of the demo have evidenced the potential impact that MV resources can produce in regulating voltage levels on HV grids. In detail, the analysis of the solution in terms of scalability and replicability pointed out overall scores of about 69% for scalability and about 63% for replicability (Table 9.5). These values evidenced that the solution could be scalable and replicable, but barriers emerged. The most critical is the technical area. Indeed, although the hardware and software of the aggregator platform were modular, the absence of automatic interfaces for remotely controlling the resources is a very relevant barrier for a flexibility service requiring a fast response. Also, the connectivity of the solution obtained by a 4G LTE router was found to be not adequate for the examined service. The scores of economic and acceptance indicators, when related to scalability, pointed out the absence of barriers. Differently, the scores of replicability evidenced as barriers the need to investigate the local territorial factors of market scenarios and economic remuneration. Indeed, resource features such as response time and accuracy requirements can depend on national grid code and regional regulation.

The main recommendations emerged by analysing the results obtained are related to the need to:

- study on a standardized method to transform the input set-points in control variables at the local resources for scalability needs;
- verify the ratio between the rated powers of the controllable resource with respect to the entire plant and the features of the HV/MV connection power scheme for replicability needs;
- investigate regulation methods for HV grids in order to enhance flexibility services of MV resources.

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11 Attachment

[ANNEX-1] WP5_SRA_Questionnaire_format.xlsx

12 Appendix

12.1 Used technologies

In the following Table 12.1 - Table 12.8, details concerning the implementation of the technical solution are provided.

In particular, the columns of the tables detail the information on:

- *HW component*: the single HW component of the solution should be listed;
- *Constituted by:* if the single HW component is constituted by other significant elementary devices, each elementary device should be listed.
- *Quantity:* the specific quantity related to network/plant/solution element;
- *HW cost [€]:* specify the cost of the component, or, alternatively, the total cost of the implemented demo (in this case, it is necessary to know how big is the demo;
- *SW component:* is it necessary a dedicated (i.e., ad hoc implemented), or a commercial, or an open-source SW?
- *SW quantity:* is it necessary to install the SW in one or more HW positions?
- *SW cost [€]:* cost of the SW development/implementation or cost of purchasing a commercial SW
- *Communication with (protocol):* does the HW o SW component communicate with other components? If yes, what was the protocol used?

Table 12.1 HW&SW – PREVEL (UC 1)

HW component	Constituted by	HW quantity	HW cost [€]	SW component	SW quantity	SW cost [€]	Communication with (protocol)
workstation	A VM with 18 processors Intel Xeon E5-2660 2 GHz; 48 GB of RAM and 32 GB of SWAP. File system of 30 GB for OS (linux Red Hat Enterprise Linux Server release 7.9) and codes; 250 GB for data and database.	1 (in case of more data or speed requirements it could be necessary to increase the number of processors and the memory capacity)		PrevDTR	1 (it is necessary to install the SW in one HW position)	The SW was developed for the project, and used only opensource software (scripts written in perl5, post-processing in R)	SW interacts with file systems mounted via cifs, and databases (MariaDB locale, Oracle)
				PREVEL	1 (it is necessary to install the SW in one HW position. In this implementation the PREVDTR depends on some actions of PREVEL, so they have to be installed in the same server)	The SW was developed for the project, and used only opensource software (scripts written in perl5, post-processing in R)	SW interacts with file systems mounted via cifs, and databases (MariaDB locale, Oracle)

Table 12.2 HW&SW – Sensor-based DTR (UC 1)

HW component	Constituted by	HW quantity	HW cost [€]	SW component	SW quantity	SW cost [€]	Communication with (protocol)
master node	PC Intel Celeron 1007U/1037U Dual Core, 2M Cache, 22 nm Lithograph, CPU 8GB DDR3L RAM,128GB mSATA Solid State Disk, Fanless, Metal Case Integrated Intel HD Graphics, Max Dynamic Frequency 1GHz, 2xNICs, 4xCOM RS232, HDMI, VGA, 4xUSB 3.0, 4xUSB2.0, WiFi 802.11abg, Ethernet Card, Operating System: Windows 10 Pro	1 per primary substation					radio with sensors and web based (TCP/IP protocol) with the TSO server for forecasted data (from PREVEL)
conductor temperature module	MICCA sensor	1 per each monitored overhead line (feeder)	20 k€				radio
sensor node	Broadcom BCM2837B0,Cortex-A53, 64-bit SoC @ 1.4 GHz Features Upgraded On-board WiFi and Bluetooth Connectivity, 7" TOUCH SCREEN DISPLAY - Full Color 800 x 480 Resolution, 32 GB Evo Plus (Class 10) Micro SD Card, battery (Valve Regulated Lead Acid)	as many as needed for covering the monitored line (it is important that the sensors could see themselves- depending on the territory orography - and capture the differences in the environmental conditions, it could be sufficient 1 every 5/10 km)	3-4 k€				radio

Table 12.3 HW&SW – Weather-based DTR (UC 1)

HW component	Constituted by	HW quantity	HW cost [€]	SW component	SW quantity	SW cost [€]	Communication with (protocol)
Processor	multi-core pc	1		The WB-DTR is a program implemented in C language that runs in a multi-core processor	1		The WB-DTR received the continuous input from PREVEL and sends its output to the Z-EMS, via web (TCP/IP protocol)

Table 12.4 HW&SW - Z-EMS (UC 1)

HW component	Constituted by	HW quantity	cost [€]	SW component	SW quantity	SW cost [€]	Communication with (protocol)
		1		Z-EMS	It is necessary to install the SW in one HW position	The SW developed for the project uses both opensource SW (scripts written in python) and CPLEX	SW interacts with a file system via cifs, and read csv and excel dataset
TERNA provided a dedicated Virtual Machine for the Dashboard deployment	2CPU, 8GB RAM, 250GB of HD, Windows 10	1		Dashboard	1 per EMS (Energy Management System)	The SW was developed by ENG in the context of the OSMOSE project. It does not rely to any commercial third party software or library	Cifs/Smb is used to access to shared folders (Share Z-EMS) in order to retrieve the whole Z-EMS output dataset at each run execution and to retrieve some relevant input such as the loadabily curves and the offers file from BSP. The Cifs/Smb is used also to store the BDE file that will be retrieved by each BSP via MFT. Http rest is used to communicate with the HoD
		1		Hand of Data and Scheduler	1	The SW was developed by ENG in the context of the OSMOSE project. It does not rely to any commercial third party software or library	The HoD communicates with TERNA systems in order to retrieve relevant data and with the other software components involved in the WP5 demo. TCP is the protocol used to communicate with TERNA systems (Data bases) and with the two Master Node DTR, Cifs/Smb is used to access to shared folders (Share Z-EMS) used to store the whole Z-EMS input/output dataset at each run execution. Http rest is used by the HoD to communicate with the Dashboard

Table 12.5 HW&SW - DSR (UC 1)

HW component	Constituted by	HW quantity	cost [€]	SW component	SW quantity	SW cost [€]	Communication with (protocol)
LOCAL CONTROLLER	Small Form Cabinet: 1000 x 800 x 400	qty built: 7 qty commissioned: 5 qty stand-by: 1 qty in stock: 1 each cabinet composed by: nr. 1 ABB RTU540 a DIN rail RTU in metal housing nr. 1 ABB 520AOD01 Din rail - analog OUT nr. 1 Ethernet Switch HIRSCHMANN SPIDER-SL-40 nr. 1 Power Meter Acuvim II-M-5A-P2 nr. 1 TC MGUARD RS2000 4G VPN nr. 1 TC ANT MOBILE WALL 5M	16'600	Industrial firmware ABB RTU540 (release 12.0), no special or customized software development deployed	qty on board 1 (each cabinet): RTU500 License, with 250 datapoints, PLC function, Archiving and HMI features	5'000	VPN-IPSEC to enabling the remote connection. IEC 60870-5-104 to establish the real-time data acquisition and remote controls
				TecnoWatt "Exergy Platform" (aggregation platform)	1	40000 € (for development, set up and utilization)	IEC 60870-5-104 (with on site RTU) / MFT (with Terna) / Online access for Edison

Table 12.6 HW&SW – RES for SI and AVC in the case of BESS (UC 2)

HW component	Constituted by	HW quantity	cost [€]	SW component	SW quantity	SW cost [€]	Communication with (protocol)
For providing AVC, no additional HW is required. The solution is constituted by new functionalities implemented in the MASTER SCADA System of the Hybrid power plant (Wind Farm + BESS)				New functionalities implemented in the standard code of MASTER SCADA of the Hybrid power plant		80 k€ for develop and integration of the new functionalities	Standard protocol compliant with company policy
Synthetic Inertia Control Device (SICD) is the required HW to provide SI	external PLC (C-Rio of National Instruments)		25 k€	New logic and functionalities implemented		60 k€ for develop and integration of the new functionalities	Standard protocol compliant with company policy

Table 12.7 HW&SW - RES for SI and AVC without BESS (UC 2)

HW component	Constituted by	HW quantity	cost [€]	SW component	SW quantity	SW cost [€]	Communication with (protocol)
For AVC, SCADA 2 existing monitoring and controlling platform with a local embedded (windows based) and a centralized datacenter with a dedicated virtual machine which is connected to TSO for monitoring and controlling set-points. Additional HW could be required to improve the dynamic response of the plant (in particular the response time)				Software implementation on the local embedded Windows based			
SI was developed at laboratory level, no cost estimation is possible							

Table 12.8 HW&SW - DSR for AVC (UC 3)

HW component	Constituted by	HW quantity	cost [€]	SW component	SW quantity	SW cost [€]	Communication with (protocol)
LOCAL CONTROLLER	Small Form Cabinet: 1000 x 800 x 400	qty built: 7 qty commissioned: 5 qty stand-by: 1 qty in stock: 1 each cabinet composed by: nr. 1 ABB RTU540 a DIN rail RTU in metal housing nr. 1 ABB 520AOD01 Din rail - analog OUT nr. 1 Ethernet Switch HIRSCHMANN SPIDER-SL-40 nr. 1 Power Meter Acuvim II-M-5A-P2 nr. 1 TC MGUARD RS2000 4G VPN nr. 1 TC ANT MOBILE WALL 5M	16'600	Industrial firmware ABB RTU540 (release 12.0), no special or customized software development deployed	qty on board 1 (each cabinet): RTU500 License, with 250 datapoints, PLC function, Archiving and HMI features	5'000	VPN-IPSEC to enabling the remote connection. IEC 60870-5-104 to establish the real-time data acquisition and remote controls
				TecnoWatt "Exergy Platform" (aggregation platform)	1	40000 € (for development, set up and utilization)	IEC 60870-5-104 (with on site RTU) / MFT (with Terna) / Online access for Edison