Smart TSO-DSO interaction schemes, market architectures and ICT Solutions for the integration of ancillary services from demand side management and distributed generation

Characterization of flexibility resources and distribution networks

D1.2

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About SmartNet

The project SmartNet (http://smartnet-project.eu) aims at providing architectures for optimized interaction between TSOs and DSOs in managing the exchange of information for monitoring, acquiring and operating ancillary services (frequency control, frequency restoration, congestion management and voltage regulation) both at local and national level, taking into account the European context. Local needs for ancillary services in distribution systems should be able to co-exist with system needs for balancing and congestion management. Resources located in distribution systems, like demand side management and distributed generation, are supposed to participate to the provision of ancillary services both locally and for the entire power system in the context of competitive ancillary services markets.

Within SmartNet, answers are sought for to the following questions:

- Which ancillary services could be provided from distribution grid level to the whole power system?
- How should the coordination between TSOs and DSOs be organized to optimize the processes of procurement and activation of flexibility by system operators?
- How should the architectures of the real time markets (in particular the markets for frequency restoration and congestion management) be consequently revised?
- What information has to be exchanged between system operators and how should the communication (ICT) be organized to guarantee observability and control of distributed generation, flexible demand and storage systems?

The objective is to develop an ad hoc simulation platform able to model physical network, market and ICT in order to analyse three national cases (Italy, Denmark, Spain). Different TSO-DSO coordination schemes are compared with reference to three selected national cases (Italian, Danish, Spanish).

The simulation platform is then scaled up to a full replica lab, where the performance of real controller devices is tested.

In addition, three physical pilots are developed for the same national cases testing specific technological solutions regarding:

- monitoring of generators in distribution networks while enabling them to participate to frequency and voltage regulation,
- capability of flexible demand to provide ancillary services for the system (thermal inertia of indoor swimming pools, distributed storage of base stations for telecommunication).

Partners

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List of Abbreviations and Acronyms

Acronym	Meaning
AC	Alternating Current
AEV	All-Electric Vehicles
AS	Ancillary Services
BEV	Battery Electric Vehicles
BRP	Balance Responsible Party
CAES	Compressed Air Energy Storage
CCGT	Combined-Cycle Gas Turbines
CHP	Combined Heat and Power
COP	Coefficient Of Performance
CMVC	Congestion Management Voltage Control
DC	Direct Current
DER	Distributed Energy Resource
DFIG	Doubly-Fed Induction Generator
DG	Distributed Generation
DPET	Distribution Power Electronic Transformer
DR	Demand Response
DSM	Demand Side Management
DSO	Distribution System Operator
DVR	Dynamic Voltage Restorer
EV	Electrical Vehicle
FACTS	Flexible Alternating Current Transmission System
FC	Fuel Cell
FCR	Frequency Containment Reserve
FFR	Fast Frequency Reserve
FRR	Frequency Restoration Reserve
FRT	Fault-Ride Through
G2V	Grid to Vehicle
GT	Gas Turbine
HV	High Voltage
HVAC	Heating Ventilation and Air-Conditioning
HVDC	High Voltage DC
ICE	Internal Combustion Engine
IG	Induction Generator
Inv	Inverter
IPC	Interphase Power Controller
LCOE	Levelized Cost Of Energy

LV	Low Voltage
LVRT	Low-Voltage-Ride-Through
MV	Medium Voltage
MVDC	Medium Voltage Direct Current
O&M	Operation and Maintenance
OLTC	On-Load-Tap-Changer
PAR	Phase Angle Regulator
PCC	Point of Common Coupling
PF	Power Factor
PHES	Pumped-Hydro Energy Storage
PHEV	Plug-in Hybrid Electric Vehicle
PLC	Power Line Communication
PV	Photovoltaic
PVC	Primary Voltage Control
R&D	Research and Development
REEV	Range-Extended Electric Vehicle
RM	Ramp Margin
RR	Restoration Reserve
SC	Synchronous Condenser
SG	Synchronous Generator
SO	System Operator
SoC	State of Charge
ST	Steam Turbine
STATCOM	Static Synchronous Compensator
STS	Static Transfer Switch
SVC	Secondary Voltage Control
SVR	Static VAR Compensator
TCL	Thermostatically Controlled Load
TSO	Transmission System Operator
TVC	Tertiary Voltage Control
UPFC	Unified Power Flow Controller
V2G	Vehicle to Grid
VRES	Variable Renewable Energy Source

Executive Summary

The technological advances in variable renewable energy sources combined with the deployment of automation and monitoring technologies as well as the regulatory changes make possible the provision of ancillary services (AS) by resources connected at the distribution network. Additionally, cost reductions in power electronics enable distribution network operators to use advanced power technologies to enhance flexibility in their network.

In order to evaluate to which extent distributed energy resources can contribute to the provision of ancillary services, simulations are planned in the context of SmartNet. Therefore, information models describing the behaviour of different categories of distributed energy resources have to be developed for this purpose.

In SmartNet, the distributed energy resources have been classified based on their physical behaviour and modelling similarities. It results in the following list of families: **Variable Renewable Energy Sources** (VRES), electrical **stationary storage**, **electrical vehicles**, **conventional generators**, **Combined Heat and Power** (CHP), **Thermostatically Controllable Loads** (TCL), **load shifting devices** and **load curtailment devices**. For each of them, a **mathematical model** that **describes their dynamics and their constraints** is proposed; the diversity of technologies inside each family is reflected in the ranges of values for each parameter. Besides knowing the amount of flexibility available at each instant to determine the quantity offered in bids (i.e. flexibility offers in terms of quantity and price on the ancillary services market), the market participants also need to know the cost of providing this flexibility in order to determine the bids price. For a generic device, the cost of flexibility provision is defined as a combination of the followings components: the **discomfort costs**; the **change of operational costs**; the **change of revenues** and the **indirect costs**. The combination of the mathematical models and the flexibility cost are necessary inputs for aggregators to extract the flexibility quantity and cost of each DER and then build their aggregation methods to define their bids.

Following this modelling task, we assessed qualitatively the **capability to provide different AS for distributed energy resources and for advanced power technologies**. The results depicted in Table 1 can be interpreted as follows: the best resources to provide frequency ancillary services are the storage systems, which have high performances and less constraints with respect to other resources. CHPs and industrial shiftable loads show high performances, due to the thermal storage system (CHPs) and the good monitoring and control (industrial processes). Wind turbines, Photovoltaic, EVs and curtailable loads have lower performance for long-duration ancillary services due to lower predictability. On the contrary the shiftable loads (wet appliances) are more suitable for long time horizon due to the latency of the response. Regarding TCLs, they can provide quite good capabilities from fast AS (FCR) to longer-duration AS (FRR and even RR in some cases), which is linked to their thermal inertial of the TCL. More generally, loads are not well suited for voltage control services as they do not provide the mechanisms to change their reactive power output.

Table 1: Capabilities of DER to provide future ancillary services

Ancillary services		Wind	PV	Stationary Storage: Batteries	Mobile Storage: EVs	CHP	TCL	Shiftable loads: Wet appliances	Shiftable loads: Industrial processes	Curtailable loads
Frequency	**FFR**									
	FCR									
	FRR									
	RR									
	RM									
Voltage	**FRTC**									
	CMVC									
	PVC									
	SVC									
	TVC									

FFR: Fast Frequency Reserve
FCR: Frequency Containment Reserve
FRR: Frequency Restoration Reserve
RR: Restoration Reserve
RM: Ramp Margin (Ramp Control)
FRTC: Fault Ride-Through Capability
CMVC: Congestion Management Voltage Control
PVC: Primary Voltage Control
SVC: Secondary Voltage Control
TVC: Tertiary Voltage Control

KEY

	Indicates very good capabilities
	Indicates good capabilities
	Indicates little capabilities
	Indicates very little capabilities
	Indicates no capabilities

This qualitative assessment was preparatory for a quantitative assessment: we evaluated for each resource family the total technical capacity for the participation to ancillary services. The results illustrated in Table 2 show the importance of the distribution system in the overall contribution. It also appears that **the available potential is far larger than the reserve needs**. However, this theoretical potential must be carefully considered since there are others factors that limit the participation of resources to the market such as the necessity of innovative control solutions in order to aggregate some assets, previous commitments on energy markets, primary use of the devices, weather conditions or time, season, or the cost associated to these control system which is a potential barrier; in reality, the available potential is lower than the maximum theoretical potential.

Table 2: Quantitative mapping of flexibility resources to ancillary services in 2030

			From DS	From TS	Absolute maximum potential availability of DERs before subjected to market and environmental conditions (MW)	Reserve needs (maximum between upward and downwards) (MW)
Frequency	aFRR	DK1	49 %	51 %	5 074	262
		IT	37 %	63 %	33 059	1 471
		ES	62 %	38 %	19 428	783
	mFRR	DK1	50 %	50 %	3 937	426
		IT	33 %	67 %	29 851	1 523
		ES	58 %	42 %	15 790	5 473

Besides the DER, another category of resources is able to enhance the network flexibility. The potential of advanced power technologies, owned and operated by network operators, has been thoroughly analysed, in particular their impact on the coordination between TSO and DSO. Four types of advanced power technologies have been considered based on a literature study: **reactive power compensator**, **distribution transformer**, **medium voltage direct current** (MVDC) networks and **Interphase Power Controller** (IPC). Apart from these devices specialized in the network management under normal conditions, we also considered two additional components able to overcome failures and contingencies: the **Static Transfer Switch** (STC) and the **Dynamic Voltage Restorer** (DVR). Finally, network operators pointed out in a survey the **importance of measurements devices** and the **high uncertainty related to the future deployment of these advanced power technologies** in their networks.

In addition to the information model for each family, a **realistic and tractable distribution network model** in line with the 2030 scenarios has been specified for each pilot country (i.e. Denmark, Italy and Spain) for the purpose of the simulations. Apart from the electrical and topological characteristics of the grid, the location and the characteristics of the flexible assets has to be specified for the simulations. Therefore, the network operators participating in the project provided information on their network such as grid models (electrical parameters, topology, etc.) or customers data (contracted power, time series measurements, etc.). An overview of the network size is shown in Table 3 below:

Table 3: Overview of the distribution networks for each country

Country	Denmark		Italy		Spain
Area	Pilot area	Extended Area	Pilot area	Extended Area	
Network size	Not Available	1500 nodes 1600 lines 1300 MV/LV transformers	160 nodes 279 lines 41 MV/LV transformers	2600 nodes 4500 lines 2155 MV/LV transformers	Not Available

The received data showed some high heterogeneity: for instance, the zones that are close to the pilot area are relatively detailed in the Italian network while for other areas of the grid the quality of the data is lower in consistency and in accuracy; in the Spanish case, no data are available at the time of writing this deliverable; for Denmark, the data are relatively consistent. Therefore, we proposed a **multi-level spatial resolution modelling approach**, which allows handling heterogeneous information, to further creating the network scenarios. This **general framework is applicable on each distribution network**, which is based on the gathering of information and downscaling. Since the data gathering activity was also performed among transmission network operators, generalities about the transmission grids are briefly presented as well.

1 Introduction

1.1 Scope of the document and methodology

The aim of the present document is to investigate the potential of the flexibility resources connected at the distribution network, in particular the distributed generation (DG), the demand side management (DSM), electric storage devices and the advanced power technologies, to provide ancillary services and enhance an active network management. We propose an information model for each distributed energy resource (DER) which is intended to be used for participating in ancillary services (AS) market, likely (but not exclusively) through aggregation. This information model contains a mathematical description of the dynamic behaviour of the resource, its constraints for flexibility provision, a formulation of the different components of costs needed to provide flexibility on the AS market, and some ranges of values for each model parameter. The activities which have been carried out to achieve these objectives are illustrated in Figure 1. They are listed hereafter:

- Creation of a taxonomy of the current and future flexible assets connected at the distribution level and that are able to provide ancillary services. The classification is based on the physical behaviour and the modelling similarities and it is the result of an extensive literature study.
- Development of a flexibility model for each family of assets based on a selected generic modelling framework and proposition of realistic range of values for the models parameters. The models have been selected based on the ones existing in the literature. Furthermore, the different cost components linked to the provision of flexibility are formulated and quantified, when possible.
- Qualitative evaluation of the DER technical capability to provide current and future ancillary services and assessment of the availability of each DER in each country for the 2030 scenario.
- Development of a methodology combining the technical capability and the availability of each asset in order to quantify the potential provision of AS by DER.

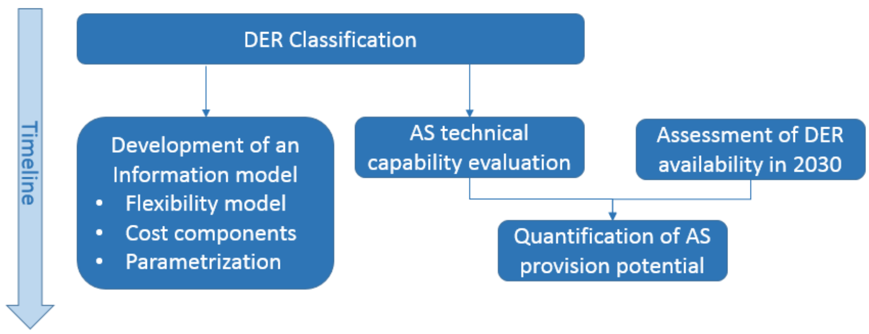

Figure 1: Timeline of the activities related to the DER

This report also presents the potential of advanced power technologies for flexibility provision. In fact network operators can own and operate their own devices in order to manage their grid, they do not necessarily need to contract services to DER. The following activities were carried out with respect to these technologies:

- Analysis of the state-of-the-art in future devices for enhanced management of the distribution system and classification;
- Elaboration and analysis of a survey submitted to network operators in which they are invited to share their views on the different devices selected;
- Evaluation of the impact of these technologies on the interactions between transmission system operator (TSO) and distribution system operator (DSO).

This deliverable also presents the main characteristics of the distribution and transmission networks of the three pilot countries (Denmark, Italy and Spain). In addition to the electrical and topological models, the size and the location of each asset in each distribution grid is required for the simulations. The following activities were done:

- Specification of the information required and gathering of data with the network operators of the pilot countries and preparation of the network models for the simulations;
- Development of a methodology to create the distribution network scenarios for each pilot country based on a multi-level resolution approach.

1.2 Structure

The report is divided into five main chapters representing the body of the document. Further information is provided in the appendices. Chapter 2 is focused on the flexible resources where the general framework is presented and where a mathematical model is presented for each family of device. Advanced power technologies are also introduced and discussed in this chapter. Chapter 3 is focusing on the provision of ancillary services with flexible resources and describes the methodology applied. Chapter 4 deals with the distribution network characteristics and the presentation of the models for each country. Finally Chapter 5 presents the multi-level spatial resolution modelling concept as well as the general framework to create the network scenarios.

2 Flexible resources: characteristics, modelling and parametrization

In this chapter, the motivation and context for classifying, modelling and characterizing the DER are first described (section 2.1). Then, a first taxonomy of the DER is proposed, based on these motivations (section 2.2). In section 2.3, a general modelling approach suitable to tackle the purposes described in section 2.1 is chosen. The model is described in a generic way. In section 2.4, the mathematical models of each DER family (defined in section 2.2) are explained as they are adaptations of the generic model, and sometimes additional requirements/models are added when necessary. In that section, the parametrization process (i.e. providing values for the model parameters) is also described (focusing on the three pilot countries). Finally, section 2.5 describes models for different advanced power technologies aiming at increasing the flexibility at the interface between the TSO and DSO networks.

2.1 Motivation

In the context of the SmartNet project, the purpose is to leverage the flexibility from distributed energy resources (generation, storage, demand response) for the provision of AS to the TSO and local services to the DSO, in a market framework. These services include frequency and voltage control (see details on current and future (at the 2030 horizon) AS in SmartNet report D1.1 [1]). Importantly, the focus is put on balancing/frequency restoration, frequency control and voltage control since other services will not likely be procured in a market-based environment in 2030 (SmartNet report D1.3 [2]). Since DER are plentiful but rather small in terms of flexibility quantity they can provide, the flexibility provided by many DER is usually leveraged by aggregators (SmartNet report D2.3 [3]), who gather all the flexibility sources and then bid flexibility offers on AS markets.

The goal of this chapter is threefold: to develop DER models, to determine the cost for individual DER to provide flexibility, and to parametrize the models.

The first goal of this chapter is to develop DER mathematical models specifying the *physical* and *dynamic behaviour* of the resources, such that the flexibility can be accurately determined and used for the provision of these AS and local services. These models are intended to be used by aggregators[1] as inputs to bring this flexibility to the market, i.e., to generate bids[2] and offer flexibility from DER for the AS markets (see [3]). Depending on the AS to be provided (balancing vs congestion vs voltage control), the level of details needed in the model can change: e.g. reactive power modelling is optional or not,

[1] If DER are large enough, they could also offer their flexibility directly on the AS market, without going through an aggregator. However, they would assume an *aggregator role* with only one DER. In the following, we will always consider that an aggregation step is necessary.

[2] Bids are for instance price-quantity curve specifying the price asked for offering different levels of extra supply or consumption of energy. More complex bids can also exist and are described in other SmartNet deliverables.

depending on whether voltage constraints are taken into account in the market clearing stage. The models should also depict the *control* possibilities of the resource, i.e. how an external agent (e.g. an aggregator) can control a DER agent (e.g. a combined heat and power (CHP) plant). On top of the mathematical model, other information are sometimes required by external agents (e.g. SO, aggregator): for instance, locational information is a crucial information to transmit when dealing with congestion/voltage control but not necessarily needed for balancing (in case there is no risk to generate congestions and/or voltage problems by activating balancing resources).

Another equally important but challenging goal is to model and determine *the cost for individual DER to provide flexibility*, on top of determining the flexibility quantity. It is needed by the aggregator to determine the prices of the bids (and also to determine the financial terms of a contract between a DER owner and a commercial aggregator).

Finally, *parametrization* of the models is crucial to provide real information to the aggregator and to the AS market. In the context of SmartNet, the main goal is to focus on parametrizing the resources located in the pilot countries (i.e. Denmark, Italy and Spain) targeted for assessing the different TSO-DSO coordination schemes. For some parameters, this parametrization may depend on the extrapolation made for the year 2030 (e.g. costs, efficiencies). Since scenarios have been defined for 2030 for these three countries in [1], the parametrisation makes sure that it is consistent with these scenarios.

2.2 Classification of the DER

In this section, a high-level hierarchical taxonomy of the DER (Table 4) is provided. This classification is mainly based on a criterion of modelling similarity, i.e. resources that can be modelled in the same way are grouped together, regardless of the technology of the resource. The difference between the technologies is of course reflected in the parametrization of the models. In Chapter 3 another taxonomy is proposed, based on the capability of DER to provide different ancillary services (AS), current or future.

Three main categories of flexible resources have been identified: energy storage, distributed generation and flexible loads. In the first category, we distinguish mobile and stationary storage since Electric Vehicles (EVs) have additional constraints that must be taken into account into the model. The classification of DG is straightforward: it is composed of Variable Renewable Energy Sources (VRES) whose electric power output is directly proportional to the primary energy resource; Combined Heat and Power (CHP); and conventional generators such as back generators. Regarding the flexible loads, which can adapt/adjust their electric consumption based on externally sent signals, they are usually divided into shiftable and curtailable loads. Even though Thermostatically Controlled Loads (TCL) can be considered as shiftable, it is more accurate to model them separately to represent the dynamics of thermal systems.

Table 4: DER taxonomy

DER taxonomy		
General	**Family**	**Technology examples**
Energy Storage	Mobile storage	Electric vehicles
	Stationary storage	Pumped Hydro Energy Storage (PHES), batteries, flywheels
Distributed generation	Variable Renewable Energy Sources (VRES)	PV (Photovoltaic), wind turbines, run of the river, …
	Combined Heat and Power (CHP)	Specific multi-energy constraints (heat demand)
	Conventional generators	Backup (fossil fuel) generators, other dispatchable generators (biogas, hydro)
Flexible loads	Thermostatically Controlled Loads (TCL)	Gathers all loads controlled by thermostat: e.g. Heating Ventilation and Air-Conditioning (HVAC), electric boiler, heat pumps, air conditioning, cooling…
	Load shifting	Loads able to **shift** their consumption: e.g. household wet appliances, industrial processes,
	Load curtailment	Loads able to **reduce** their consumption: e.g. some industrial processes, lighting…

2.3 Modelling and parametrization framework

In this section, the general modelling and parametrization frameworks are described, independently of the DER family it is applied to. First, section 2.3.1 enumerates the requirements for the type of DER model to be considered in the framework of SmartNet, and then describes the modelling approach used in this deliverable, based on these requirements. Then section 2.3.2 explains how *reactive power* (potential flexibility) capabilities are modelled in a generic way. Section 2.3.3 describes how DER can be controlled, what are the pro and cons of each option and which one fit best in the AS market framework. A generic definition and framework for the flexibility cost is proposed in section 2.3.4 . Finally, section 2.3.5 describes the general parametrization process applied to each DER family model in the pilot countries.

2.3.1 Generic model

Leveraging the flexibility of DER for providing AS needs an assessment of this flexibility, which requires using mathematical models to describe (in a simplified way) the DER dynamical process. To reach this goal, the modelling approach has to:

- Be **generic,** to accurately describe the behaviour of any energy resource usually located in distribution grids (i.e. technology independent);

- Be able to **represent** the **dynamics** of the DER, such that flexibility can be accurately retrieved from the model;
- Be able to **represent** the **main** physical/technical **constraints** relevant to leverage the flexibility from these resources;
- Be **simple** enough (e.g. linear model) to allow a **tractable** approach for the **aggregation** of the models into market products.

In this chapter, unless otherwise stated (in some particular cases), we use and adapt the formalism described in [4] to model the DER behaviour, since it is a modelling approach which has the four requested qualities. In that approach, the authors develop the notion of power node (see Figure 2), that represent a simple storage system for any process (generator, load, storage, or a combination of these, e.g. a microgrid). This model is *continuous* since it is the natural way to describe the dynamics of the DER processes. However, translation into a discrete model is a straightforward process, necessary at some point in the implementation because, for instance, electricity markets are typically not implemented in continuous time (there is a discretization with fixed duration time steps). This discretization step is out of scope of this deliverable but is treated in SmartNet deliverable D2.3 [3]. Moreover, the model is also *deterministic* (as opposed to stochastic): even though some of the variables in equation (1) could be stochastic.

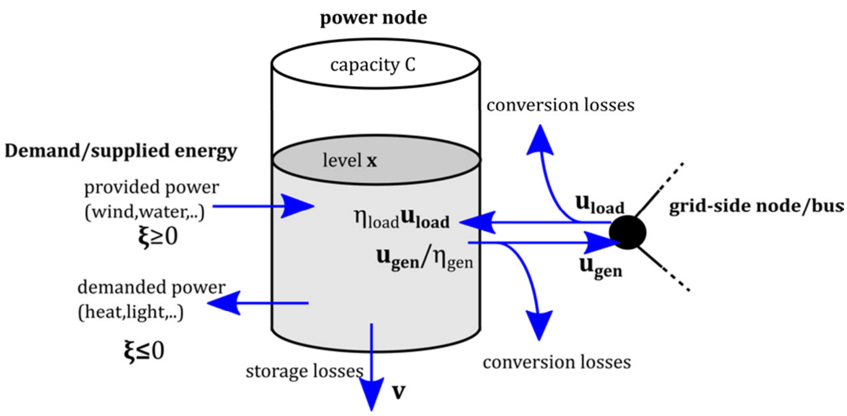

Figure 2 Illustration of the power node concept (figure adapted from Fig. 2 in [4])

The generic model of the DER consists first in the following differential equation describing the dynamics of the lumped physical system:

$$C\dot{x} = \eta_{load}\boldsymbol{u_{load}} - \frac{\boldsymbol{u_{gen}}}{\eta_{gen}} + \boldsymbol{\xi} - \boldsymbol{v} \tag{1}$$

where the *parameters* are:

- $C \geq 0$ is the energy storage capacity of the flexible DER [kWh]
- $\eta_{load} \geq 0$ is the grid-to-DER energy conversion efficiency [no unit], between 0 and 1
- $\eta_{gen} \geq 0$ is the DER-to-grid energy conversion efficiency [no unit], between 0 and 1

and the *variables* (highlighted in bold) are:

- $\boldsymbol{x} \geq 0$ is the normalized energy storage level [no unit]: **state** variable
- $\boldsymbol{u_{load}} \geq 0$ is the electric active power consumed from the grid [kW]
- $\boldsymbol{u_{gen}} \geq 0$ is the electric active power injected to the grid [kW]
- $\boldsymbol{\xi}$ is the provided ($\xi > 0$, e.g. wind, water, fuel) or demanded ($\xi < 0$, e.g. heat, light demand) power [kW] by external process.
- $\boldsymbol{v} \geq 0$ is the power representing the storage losses [kW]

Depending on the intended use, not all variables are needed to describe a particular DER family. Also, depending on the DER type, some variables are controllable, and others are disturbances driven by external processes. The following sections will describe how this generic model fits each DER family. Note that in the most general case, the efficiencies η_{load} and η_{gen} can be varying and dependent on state x (in that case, these are not parameters, but functions of the state variable(s)). However, in this case, the model would become non-linear: that would perhaps be more accurate for simulation purposes, but not necessary for the high-level purpose of aggregation work for which these models are designed for (see section 2.1). The above remark can also apply to the storage losses variables v.

On top of the state dynamic equation, the model also represents the physical constraints applied to some of the above variables. First, the minimum and maximum active power injected on (consumed from) the grid represent real technical constraints on the represented DER:

$$0 \leq u_{gen}^{min} \leq \boldsymbol{u_{gen}} \leq u_{gen}^{max} \tag{2}$$

$$0 \leq u_{load}^{min} \leq \boldsymbol{u_{load}} \leq u_{load}^{max} \tag{3}$$

where $u_{gen}^{min}, u_{gen}^{max}, u_{load}^{min}$ and u_{load}^{max} are *parameters* representing the minimal and maximal active power in [kW] for injection and consumption. Since the energy storage capacity is normalized, the storage energy constraint is expressed as:

$$0 \leq \boldsymbol{x} \leq 1. \tag{4}$$

Ramping constraints on the rate of change of active power injected and/or consumed can also be added.

$$r_{gen}^{min} \leq \dot{\boldsymbol{u}}_{\boldsymbol{gen}} \leq r_{gen}^{max} \tag{5}$$

$$r_{load}^{min} \leq \dot{\boldsymbol{u}}_{\boldsymbol{load}} \leq r_{load}^{max} \tag{6}$$

where $r_{gen}^{min}, r_{gen}^{max}, r_{load}^{min}$ and r_{load}^{max} are *parameters* representing the minimal and maximal rate of change of active power in [kW/time unit] for injection and consumption. In practice, some of these constraints do not need to be explicitly expressed for each DER family, e.g. if a resource can ramp up very fast compared to the timing of the flexibility service requested, the constraint does not need to be modelled. On top of that, additional constraints that are specific to each DER family might be introduced.

Finally, the locational information of the DER is important and needs to be transferred to the aggregator in most cases. Indeed, apart for balancing service where the location is not important at all for the system operator (SO), other AS like congestion and/or voltage control require that the SO knows some locational information about the resources he activates to solve a problem. This locational information does not necessarily need to be very detailed (the granularity of the location information should be decided by regulators in collaboration with SO).

2.3.2 Reactive power model

The previous section focused on the modelling of how active power ($\boldsymbol{u_{gen}}, \boldsymbol{u_{load}}$) of DER can evolve (dynamic model) and is constrained. However, *reactive power* capabilities and constraints are also important to describe in the context of the provision of AS and local services. For instance, reactive power can be used to solve voltage problems at local level. Alternatively, taking the DER reactive power into account can be used to ensure that no voltage problems are caused by the provision of active power for other AS (balancing, congestion management).

Depending on the type of DER and also mostly on the grid coupling technology (see [5], [6]), several types of capabilities for the reactive-active power can be distinguished: circular capability, rectangular capability, fixed power factor. The goal of this section is not to describe the grid coupling technologies and models in details, but to provide a framework to quantify the flexibility in reactive power for the DER.

The framework for the modelling is adapted from [7], where power node modelling framework is extended to reactive power, in a generic way. Figure 3 illustrates this model and can be linked to Figure 2 easily.

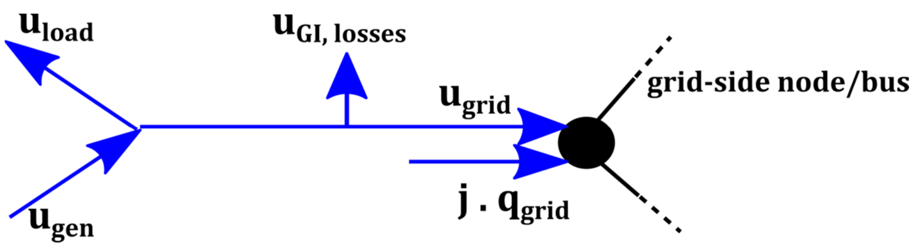

Figure 3: Illustration of the reactive power, with link to possible grid interface (GI) technology.

In particular, the complex power flow can be expressed as:

$$\boldsymbol{s_{grid}} = \boldsymbol{u_{grid}} + j \cdot \boldsymbol{q_{grid}} \tag{7}$$

where $\boldsymbol{q_{grid}}$ is the reactive power injected (absorbed from, if negative) into the grid and $\boldsymbol{u_{grid}}$ is the active power injected into the grid (absorbed from, if negative).

$$\boldsymbol{u_{grid}} = \boldsymbol{u_{gen}} - \boldsymbol{u_{load}} - \boldsymbol{u_{GI,losses}} \tag{8}$$

where $\boldsymbol{u_{GI,losses}}$ represents the losses at the grid interface level (if any) due to standby power consumption and efficiencies of the grid interface to go from active to complex power [7] (mostly applies to inverters).

For some distributed resources and associated grid interfaces (e.g. inverters), there is no specific limit in the amount of reactive power vs active power, except for the max apparent power s^{max} of the grid interface (max thermal capacities) and the maximum active power of the device itself (u^{max}) . In this case, the resource is said to have *circular* capability (see Figure 4A, describing the case $s^{max} = u^{max}$),

$$0 \leq \boldsymbol{u}_{\boldsymbol{grid}}^{2} + \boldsymbol{q}_{\boldsymbol{grid}}^{2} \leq (s^{max})^{2} \tag{9}$$

Having the circular capability, the reactive power flexibility of a DER is quite large but is linked to the active power quantity if the latter is close to the maximum apparent power: in case the active power is close to the maximum, then there is not much flexibility in reactive power. Nevertheless, this flexibility can be largely extended (see Figure 4B) if the maximum apparent power of the grid interface is oversized (see [6] for instance) with respect to the maximum active power of the device itself ($s^{max} > u^{max}$).

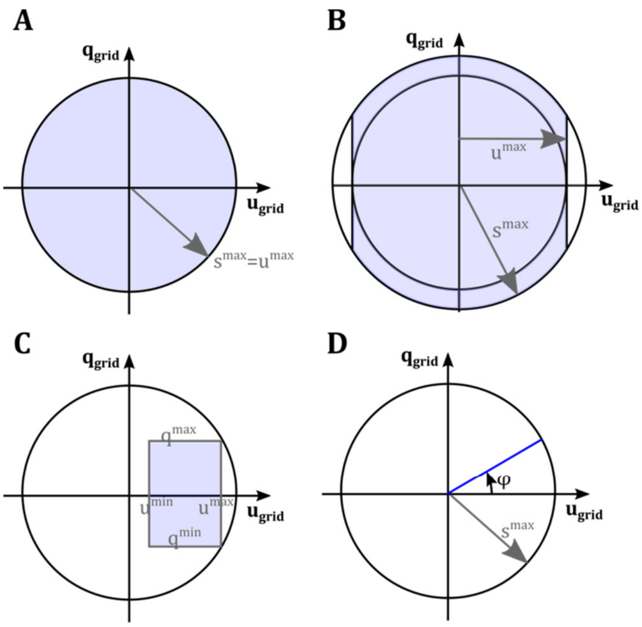

Figure 4: Active and reactive power control freedom (light blue areas or line). (A) Circular capability (B) Circular capability with oversizing (C) Rectangular capability (D) Fixed power factor

For other distributed resources (and specific grid interface types), relatively complex physical capabilities (linked to the grid interface type) can be expressed in the active-reactive power plane, and can often be simplified to a rectangular capability (see Figure 4C). As an example, some wind turbines or CHPs are connected through directly-couple synchronous generators to the grid and have such approximately rectangular capabilities [5] :

$$u^{min} \leq \boldsymbol{u_{grid}} \leq u^{max} \tag{10}$$

$$q^{min} \leq \boldsymbol{q_{grid}} \leq q^{max} \tag{11}$$

In some cases (see Figure 4D), there is no flexibility in reactive power independently of the flexibility in active power. This is the case when the *power factor* (denoted PF, or also $\cos\varphi$) is fixed (either by design or because a controller forces a constant power factor for some reason). This is typically the case for loads.

$$\boldsymbol{q_{grid}} = tan\,\varphi \cdot \boldsymbol{u_{grid}} \tag{12}$$

Depending on the DER family, one or several of these cases applies and will be explained in section 2.4. Next subsection describes the different ways in which the active and reactive power variables can be controlled.

2.3.3 Control strategies

In the previous sections, a simplified generic dynamical model of DERs was described. In this section, the focus is on the different ways the relevant electric power variables of DER can be **controlled**. Figure 5 describes high-level categories on how the DER can be controlled (in particular, in our case, the active and reactive power generation and/or consumption), inspired by categories defined in [8]–[10]. One criterion to classify the control families is the location of the *decision making* to control the DER: either *locally* by the DER (following some local objective set by user and possibly managed by the local energy management system), or *centrally* by some external higher-level entity e.g. (aggregator, system operator …), in agreement with the DER owner. Note that for the **local decision making**, it does not mean that signals from external agents are not taken into account (e.g. price signals), but the local energy management system has the final decision on what to do (and not an external agent, like it is for **central decision making**). Another criterion for classification is the *communication* type between the DER (local controller) and the possible central higher-level entity: there can be no communication, one-way communication (signals from high-level to DER) or two-ways communication (signals from high-level to DER and from DER to high-level).

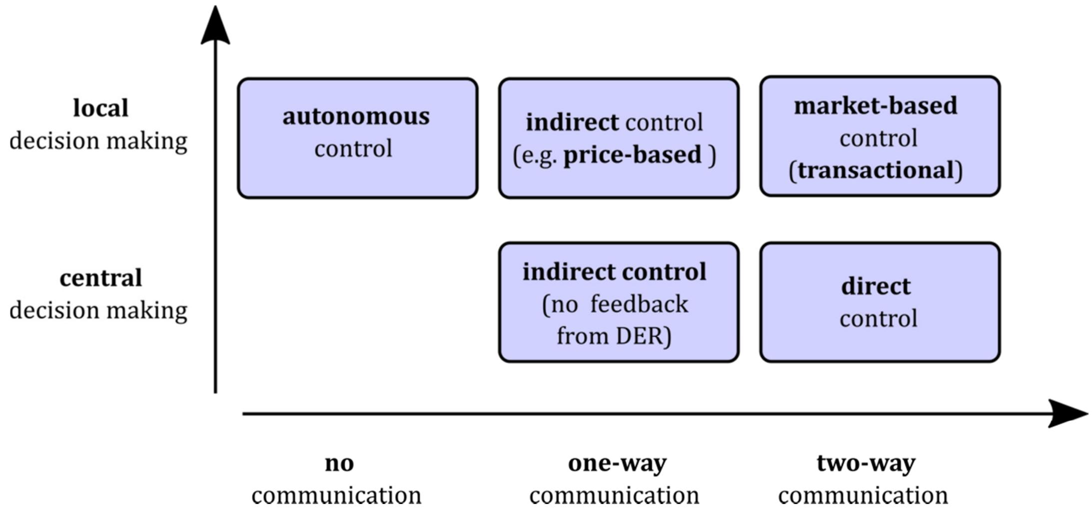

Figure 5: Different DER controlling (Figure inspired from Fig 1 in [10]).

Five different control categories can be distinguished on basis of these two criteria.

- The *autonomous control* category gathers all DER controllers for which decisions are only based on local signals (i.e. no external signal is taken into account from another external entity or agent). As a general example, this can be a local thermostat in a residential house where the reference temperature is set by the user (and no signal is sent by an external agent to control/impact the DER control: e.g. no sensitivity to possible price signals). In the context of AS, this type of control is particularly suited for fast response services like frequency control or voltage control: a local controller compares some local reference voltage or frequency and the local measurements, and adjusts the active/reactive power according to some local control law (e.g. classical frequency and voltage droop control, see [11], [12]).
- The *indirect (price-based)* control ([8]–[10], [13], [14]) consists for an external agent to send signals (e.g. price-based) to the DER controller, which can take it into account, together with its own local objectives to adjust the power consumption/generation of the DER. In this situation, there is no feedback from state or power consumption/generation from DER to the external agent. Since no (on-line) feedback is given, the external agent (i.e. the aggregator) must learn to estimate (adaptively) what is the aggregated power response corresponding to a price signal ([13], [15], e.g. based on some aggregated measurement of active power variation in response to price [9]).
- The *indirect (no feedback from DER)* control approach is indirect in the sense that no feedback from DER is sent to the external agent (one way communication), but this is sometimes also called innovative direct approach [9]. In this context, an external agent does not directly control the active and reactive power of a DER, but instead sends requirements to the local DER controller based on some indirect variable (e.g. increase or decrease or enlarge the temperature setpoint constraints, which in turn affect the power consumption). As opposed

to the price-based indirect control, the decision making is not locally made: the local DER is required to follow the constraints required by the external agent.

- The *direct control* category gathers DER which have agreed (through agreement or bilateral contracts) to let an external agent (e.g. aggregator) control directly the DER through two-way communication (see [9], [16], [17]): DER reports its current state (e.g. state of charge of storage) and current reactive/active power (and even possibly prediction/schedule of it over time [9]) to the aggregator platform/controller, which in turns sends control signals to the DER (i.e. the aggregator directly controls the active and reactive power of the DER).
- The *market-based* control (also called *transactional* control [10], [18]) category (see [19]) differs from *direct control* in the sense that local agent (DER agent) is autonomous in its decision (local objective is priority). The control is based on an automated bid-based market where aggregator and multiple DERs send their bids. These communication requirements are bi-directional, but by contrast to the *direct* control approach, the aggregator is not aware of the state of type of DER (only bids info is exchanged). This approach is however as powerful as direct control according to [8].

Direct control is the best option regarding reliability for short-time AS since for indirect price-based control, the response is much less certain since the external agent (aggregator) must build some relationship linking price and response. Most of the time, this relationship is based on statistical information and so the response is not deterministic (however, in some cases, this relationship can be deterministic, e.g. for some industrial consumer). However, depending on DER type, an aggregator could envision to use both direct and indirect controls in a general strategy, even for AS provision [9], [20], since indirect control could allow to efficiently reach a large number of small DER, with an easy scaling of the communications needs. This choice is discussed in [3] which develop aggregation method(s) to leverage the DER flexibility into bids on AS markets.

In the remainder of this chapter, only modelling details needed for AS which can be traded in a real-time market are considered. For instance, the local controllers needed for Frequency Containment Reserve (FCR) or local voltage regulation are not described. Also, unless otherwise stated, active and reactive power are assumed to be directly controlled and DER state and control commands are assumed to be sent to external agent (the aggregator). Therefore, local controllers are in general not further described in the following.

In this context of direct control, on top of communicating information on the available flexibility (or information allowing to determine it), each DER needs to transfer some information to the aggregator regarding the cost of providing flexibility for AS, a necessary information for the aggregator to determine bidding prices on the AS markets. Section 2.3.4 describes the general flexibility cost framework applied to a generic DER, then particularities will be described in section 2.4.

2.3.4 Flexibility cost framework

The goal of this general section is to describe the different main components of the cost (or revenue) for DER to provide flexibility to an aggregator (see [3]), which will use them in turn to determine the prices of the bids to be proposed on the AS markets. More discussion and details will be provided for each DER family (see section 2.4) since it can be very specific to a family, and even inside a family, there are different options.

In the *direct control* scheme (e.g. aggregator controls DER resources in a two-way communication), not only the current DER state (see equation (1)) is necessary, but also physical characteristics and/or constraints of the DER (equations (2) to (6)). A DER agent should also estimate the additional cost (or change of cost) implied by the provision of flexibility for AS. This information then needs to be sent to the aggregator 1) to settle financial agreements between aggregator and DER agent and, 2) to determine the bid prices on the market (see [3] for details).

In indirect schemes, this flexibility cost framework is of course not necessary in practice since information on the change of cost due to flexibility provision is not communicated from DER to aggregator, but it is assumed that the aggregator can learn in an adaptive way [13] through time how a pool of DERs responds to a price signal[3].

If a DER agent does not provide any flexibility in the considered AS market or flexibility activation mechanisms, the net power profile of the DER follows a reference situation[4], denoted *baseline* in the following ($u_{grid}^{baseline}$, see blue curves in Figure 6). A DER agent provides a flexibility $\boldsymbol{\Delta u_{grid}}$ (an increase or decrease of the net power injection for a specific amount of time Δt, see green areas in Figure 6) with respect to this *baseline* power profile. The DER cost (or revenue) to provide flexibility $\boldsymbol{\Delta u_{grid}}$ to an aggregator can be defined as the sum of all changes in costs and/or revenues (except the remuneration/payment of the flexibility by the aggregator) compared to the *baseline* situation. The cost of providing flexibility of course depends both the magnitude and sign of the flexibility provided, $\boldsymbol{\Delta u_{grid}}$, but also on the baseline power profile and other factors.

$$Flexibility\ Cost\left(\boldsymbol{\Delta u_{grid}}, u_{grid}^{baseline}\right) = Cost\left(u_{grid}^{baseline} + \boldsymbol{\Delta u_{grid}}\right) - Cost\left(u_{grid}^{baseline}\right) \tag{13}$$

- If the flexibility cost is *positive*, then the DER agent wants to receive a minimum amount of money for providing this flexibility. For instance, a CHP can increase the production of electricity ($\boldsymbol{\Delta u_{grid}} > 0$) on a request of the aggregator, and usually requests to be paid for doing so since the CHP has additional fuel costs to increase the power generation compared to the baseline case.

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[3] However, considering the indirect approach, in the context of SmartNet, data are missing, thus this flexibility cost information and the individual physical DER model could potentially be used to simulate the DER behaviour and some artificial response to price-based control, to help the aggregator to build some statistical knowledge on the price-responsiveness of a pool of DER.

- If the flexibility cost is *negative* (i.e. the DER agent makes a profit by providing the flexibility), then the DER agent agrees to pay a maximum amount of money to the aggregator for providing the flexibility. For instance, a CHP can decrease its production ($\boldsymbol{\Delta u_{grid}} < 0$) on request of the aggregator (see Figure 6A), and avoids fuel and operational cost to reduce the power generation compared to the baseline case.

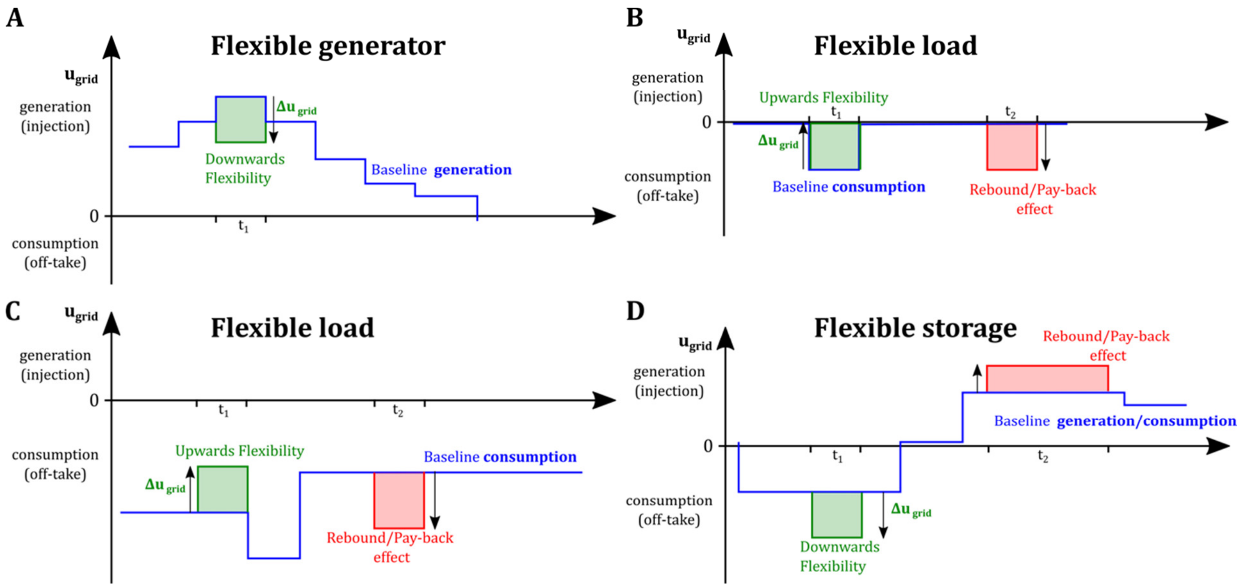

*Figure 6: Examples of baseline power consumption or generation profiles and provision of flexibility (green line during time step t_1), with or without rebound/payback effects (green line during time step t_2): **(A)** Flexible generator **(B)** Flexible atomic load [5] **(C)** Flexible load **(D)** Storage.*

Typically, the flexibility cost can be conceptually divided into several cost components:

$$\begin{aligned} Flexibility\ Cost\left(\boldsymbol{\Delta u_{grid}}, u_{grid}^{baseline}\right) &= discomfort\ cost\left(\boldsymbol{\Delta u_{grid}}, u_{grid}^{baseline}\right) \\ &+ \Delta op.costs\left(\boldsymbol{\Delta u_{grid}}, u_{grid}^{baseline}\right) \\ &+ \Delta revenues\left(\boldsymbol{\Delta u_{grid}}, u_{grid}^{baseline}\right) \\ &+ indirect\ cost\left(\boldsymbol{\Delta u_{grid}}, u_{grid}^{baseline}\right) \end{aligned} \tag{14}$$

where:

- $discomfort\ cost$ is the cost related to a loss of comfort for the DER user/owner by providing the flexibility (it mainly relates to flexible loads). For instance, it can represent the cost that a consumer attributes to having 1°C less in his house compared to the temperature setpoint chosen by the user, to allow consuming less if required by the aggregator (see Figure 6C and Figure 7B).

[5] An atomic load is a load that can be shifted in time but once it is stared, it cannot be interrupted [69]

- $\Delta op.costs = op.cost(u_{grid}^{baseline} + \boldsymbol{\Delta u_{grid}}) - op.cost(u_{grid}^{baseline})$ represents the change of operational costs for the DER between the activated flexible profile, $u_{grid}^{baseline} + \boldsymbol{\Delta u_{grid}}$, and the baseline profile $u_{grid}^{baseline}$ **during** the activation of the flexibility. It typically includes (not exhaustive):
  - fuel costs
  - gases emission costs (CO2, …)
  - maintenance/aging costs
  - start-up and shut-down costs
  - other variable costs (e.g. in process industry: storage costs, raw material costs, …)
  - electricity consumption costs (as an example, see Figure 7C)
- $\Delta revenues = revenues(u_{grid}^{baseline} + \boldsymbol{\Delta u_{grid}}) - revenues(u_{grid}^{baseline})$ represents the change of revenues for the DER agent between the activated flexible profile, $u_{grid}^{baseline} + \boldsymbol{\Delta u_{grid}}$, and the baseline profile $u_{grid}^{baseline}$ **during** the activation of the flexibility. This can include:
  - revenues from subsidies
  - product sales (in process industry)
  - electricity production sales
- *indirect cost* represents all the changes of costs/revenues indirectly implied by the provision of the flexibility, typically at a time **later** than the activation of the flexibility (see Figure 6B, C and D). This is the case when there are rebound/payback effects, which are not part of the provided flexibility. For instance, thermostatically controlled loads (TCL) can provide flexibility but at the price of an increase of electric consumption [21] and a possible change of price of the electricity, depending on the tariff structure to which the DER agent is exposed (see Figure 7).

Note that, most of the time, capital costs have not been included since it can be assumed that there is no change in capital costs if flexibility is provided or not, except for DER only serving the purpose to provide flexibility services (e.g. stationary storage in some cases). It is an open question whether they should be considered or not, especially regarding storage resources for which the investment can solely be made to provide flexibility services. However, including capital costs for storage and not for other resources could artificially decrease the chance for storage resources to provide AS, since they would then likely be expensive resources. In SmartNet, investments decisions are not made but rather scenarios for 2030 are considered, and simulations will focus on simulating real-time markets, so capital costs are not considered for the remainder of this deliverable.

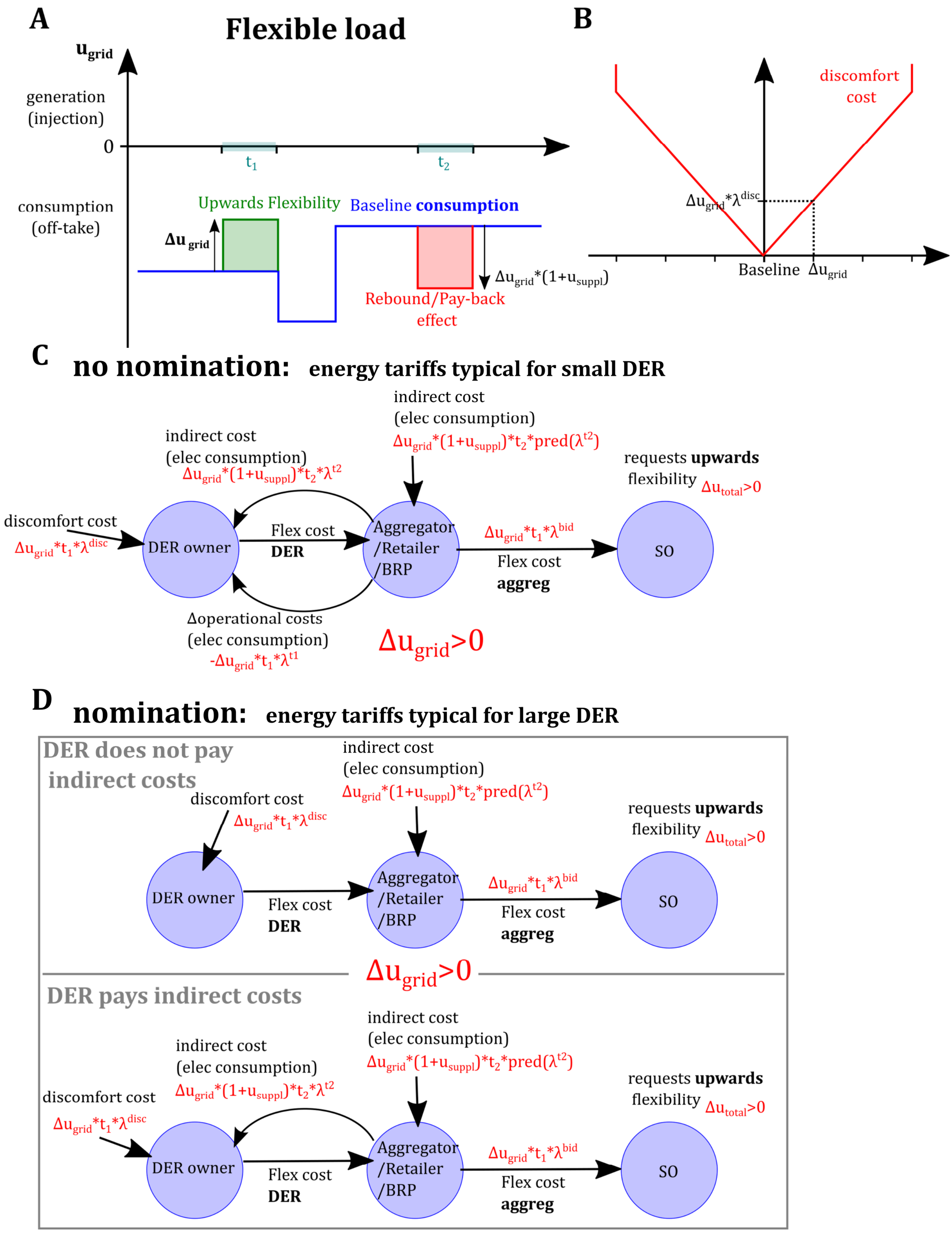

Figure 7: Flexibility cost framework: differentiating flexibility cost of DER and aggregator/BRP/retailer

Regarding changes in electricity energy consumption and/or production costs, two main different cases can be considered for a DER agent[6]: **1) no nomination** procedure: the DER agent pays the retailer ex-post (resp. gets paid) for the real consumption (resp. production) over time (sum of both usual behaviour and flexibility provision). This is typically the case for small consumers/producers like households, tertiary buildings. **2) nomination** procedure: the DER agent nominates his baseline power profile *ex-ante* (in advance) to the retailer and pays him (gets paid) according to the agreed tariff[7] (e.g. day-ahead price). This is for instance the case for some energy-intensive industrial processes. In the first case, providing flexibility implies a change in cost/revenue due to electricity consumption/generation for the DER (see Figure 7C), while in the second case, this is not necessarily observed (see Figure 7D).

As an example, Figure 7A illustrates the provision of upwards flexibility of a TCL. One component of the flexibility cost is the discomfort cost (Figure 7B[8]). Also, there is some rebound effect[9] occurring during time step t_2, with an additional[10] consumption of electricity with respect to the baseline consumption, $\boldsymbol{\Delta u_{grid}}(1+u_{suppl})\cdot t_2$, where u_{suppl} represents the percentage of additional consumption due to the rebound effect, e.g. $u_{suppl}=10\%$). In the **no nomination** case, the DER flexibility costs includes other components on top of discomfort costs (see Figure 7C).

$$\begin{aligned} DER\ Flexibility\ Cost(\boldsymbol{\Delta u_{grid}}) = (\boldsymbol{\Delta u_{grid}}\cdot t_1)\cdot \lambda^{disc} \\ -(\boldsymbol{\Delta u_{grid}}\cdot t_1)\cdot \lambda^{t_1} \\ +(\boldsymbol{\Delta u_{grid}}(1+u_{suppl})\cdot t_2)\cdot \lambda^{t_2} \end{aligned} \quad (15)$$

where λ^{t_1} and λ^{t_2} are the electricity tariffs for the DER agent for period t_1 and t_2, and λ^{disc} is the discomfort cost (€/kW) associated to the flexibility provision $\boldsymbol{\Delta u_{grid}}$. The second term represents the spared electricity consumption cost during time t_1, while the third term represents the increased consumption cost during time t_2 (rebound effect). Thus, the exact flexibility cost for the DER depends on the tariff structure: e.g. flat tariff ($\lambda^{t_1}=\lambda^{t_2}$), peak and off-peak tariffs (possibly different values for λ^{t_1} and λ^{t_2}), day-ahead based tariffs (possibly different values for λ^{t_1} and λ^{t_2}).

In the **nomination** case, two subcases are distinguished: A) either the indirect cost (payback/rebound effect) is paid by the DER agent (see Figure 7D, bottom), B) either the indirect cost is not paid by the DER

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[6] In the following discussion, we assume only two agents (on top of system operator): the DER agent and the aggregator/retailer/BRP agent: we make the assumption that the aggregator is also the retailer and BRP of this DER. Of course, other more general schemes can be considered but it is outside the scope of this deliverable (see a study [70] from the Belgian regulator (CREG), for instance).

[7] In the following, we assume that the DER agent sticks to his nominated baseline if no flexibility is provided. In practice, assuming no flexibility is provided, if the real profile is different than the nominated one, the difference is typically paid at a less convenient price (e.g. imbalance price).

[8] For the sake of simplicity, modulation of power is directly related to the discomfort cost, while in reality it is rather the deviation from the setpoint temperature which is directly linked to the user discomfort cost.

[9] Usually the rebound effect of TCLs takes place just after the end of the control action in order to recover the comfort settings as soon as possible. However, for the sale of the illustration, the rebound effect occurs later in Figure 7A.

[10] In the convention used in this deliverable, consumption is defined as <0, thus an additional consumption is actually illustrated by a larger negative quantity.

agent (see Figure 7D, top). In the latter case, the discomfort cost is the only component of the DER flexibility cost:

$$DER\ Flexibility\ Cost(\boldsymbol{\Delta u_{grid}}) = (\boldsymbol{\Delta u_{grid}} \cdot t_1) \cdot \lambda^{disc} \tag{16}$$

This means that additional consumption due to the provision of flexibility is financially taken care of by the aggregator/retailer/BRP agent. In case the DER agent has to pay the indirect cost (see Figure 7D, bottom), then the flexibility cost of the DER agent can be written as:

$$\begin{aligned} DER\ Flexibility\ Cost(\boldsymbol{\Delta u_{grid}}) = (\boldsymbol{\Delta u_{grid}} \cdot t_1) \cdot \lambda^{disc} \\ +(\boldsymbol{\Delta u_{grid}}(1 + u_{suppl}) \cdot t_2) \cdot \lambda^{t_2} \end{aligned} \tag{17}$$

where the second term represents the indirect cost. Note that the tariff for that time can be related to imbalance cost or to whatever tariff was agreed between the DER agent and the retailer for deviating from the baseline.

Thus, as a function of these three cases (no nomination, nomination + indirect cost, nomination + no indirect cost), and tariff structure, the DER agent would sell his flexibility to the aggregator at a different cost.

Flexibility cost and bidding strategy (pricing aspect) for the aggregator is explained further in [3]: of course, flexibility cost of DER is a necessary input to the aggregator to determine his overall flexibility cost and determine his bidding price. However, assuming the aggregator is also the retailer/BRP of the DER agent (for the sake of simplicity, including multiple other actors and their relationship is out of the scope of this deliverable), the aggregator flexibility cost linked to this particular DER does not depend on these three cases. As can be seen in Figure 7C and Figure 7D, whatever the case, the aggregator flexibility cost for this DER is:

$$\begin{aligned} Aggregator\ Flexibility\ Cost(\boldsymbol{\Delta u_{grid}}) = (\boldsymbol{\Delta u_{grid}} \cdot t_1) \cdot \lambda^{disc} \\ +(\boldsymbol{\Delta u_{grid}}(1 + u_{suppl}) \cdot t_2) \cdot \boldsymbol{\hat{\lambda}^{t_2}} \end{aligned} \tag{18}$$

where $\boldsymbol{\hat{\lambda}^{t_2}}$ is a prediction of the price at which the aggregator would buy the additional consumption of electricity due to the rebound/payback effect. Having estimated this flexibility cost, the aggregator uses it to determine the minimum bid price λ^{bid} required (for providing the upwards modulation $\boldsymbol{\Delta u_{grid}}$ during time interval t_1) to at least recover his flexibility costs. This condition can be written as:

$$\begin{aligned} (\boldsymbol{\Delta u_{grid}} \cdot t_1) \cdot \lambda^{bid} \geq (\boldsymbol{\Delta u_{grid}} \cdot t_1) \cdot \lambda^{disc} \\ +(\boldsymbol{\Delta u_{grid}}(1 + u_{suppl}) \cdot t_2) \cdot \boldsymbol{\hat{\lambda}^{t_2}} \end{aligned} \tag{19}$$

Then, this give a minimum price for λ^{bid}. If there were no rebound effects, we would have: $\lambda^{bid} \geq \lambda^{disc}$, while if the rebound effect is included, the larger the additional consumption u_{suppl} and the larger the predicted price $\boldsymbol{\hat{\lambda}^{t_2}}$, then the larger the bid price λ^{bid}. The aggregator flexibility costs is not described further in this document but is described extensively in [3], which deals with aggregating DER flexibility into bids for AS markets.

Figure 6 illustrates flexibility provision by different DER (flexible generator, loads, storage), with or without rebound/payback effects, assuming different baselines power profiles of consumption/generation. One important question for the DER-aggregator agents is how this baseline power profile is obtained/estimated. Many baseline power profiles can be possible, depending on the DER family but also depending on other factors (type of electricity tariff for the DER ...). For the sake of the illustration, a few examples of baselines are provided, but the list is not meant to be exhaustive:

- Baseline obtained by local (at DER level) optimization (min cost/max profit), considering day-ahead and intra-day price predictions (or some dynamic price signals sent ahead for a given period), under physical constraints (e.g. heat demand constraints of a CHP). It could typically be a method used for dispatchable generators, storage resources and large flexible loads (also possible for household flexible loads at the 2030 time horizon);
- For VRES, a natural baseline is the maximum (non-curtailed) power profile achieved (it is the result of a short-time prediction based on weather conditions);
- For storage, the baseline could also be a 0-flat power profile if the storage resource is only used to provide AS on this market;
- For industrial flexible processes, the baseline can be the result of the scheduling/planning of the industrial process;
- Baseline resulting from simple strategies: for instance, baseline for charging an EV could be to charge at max power as soon as it is plugged to the network;
- Baseline of the users following their normal daily habits (e.g. wet appliances schedule). In order to simulate such baseline, one method is to draw it from some probabilistic law: for instance, a possible baseline for wet appliances can be drawn from the statistical distribution of start times of a large pool of appliances;
- Baseline resulting from a controller trying to fit a reference signal (e.g. temperature for TCLs). Simulating this baseline for the reference signal could also be done by using some probabilistic law or some custom-based method.

In the following, we do not investigate further these different possible baselines, but the different examples above can be helpful to define and generate the scenarios used to simulate the different national cases simulations performed in the framework of the SmartNet project.

In section 2.4, the different flexibility costs components typical for each DER family will be described, such that an aggregator can have sufficient knowledge to determine the price components of the bids to be submitted on the AS market.

2.3.5 Model parametrization

Identification of models is an important topic: it is usually based on measured data (for instance, see [22]). However, in the context of the SmartNet project, the goal is to parametrize models (i.e. provide values for the model parameters) for DERs in general and not a specific particular case, so it is not realistic to parametrize the DER models based on measurements. The adopted methodology is to gather realistic ranges of values for the different model parameters (and possibly some assumption on the statistical distribution of these parameters) from the existing literature. As an example, the parameter representing the discharging efficiency of a battery can be drawn from some probabilistic distribution (e.g. a normal distribution with specific mean and standard deviation).

The next sections will discuss and summarize the parametrization aspect of the models, on top of describing the models for the different DER families.

2.4 Models and parametrization for DER

In this section, we describe the specificities of each DER family (defined in section 2.2) in terms of characteristics, model and parametrization (see section 2.3).

2.4.1 Variable Renewable Energy Sources

Variable Renewable Energy Sources (VRES) have in common that: 1) the availability of the primary energy source (e.g. wind, solar, water flow) is highly variable and 2) the electric power output is limited by the primary energy resource. Therefore, the electric power generated by these resources is highly variable and to a large extent, cannot be controlled (only curtailment is possible in some cases). In the following, we consider the main VRES, i.e. photovoltaic (PV), wind turbines, and run-of-the-river hydro power plants.

In the following, two different options are considered for the specific modelling of VRES: 1) VRES alone without any coupled storage unit, and 2) VRES coupled with a storage unit. The first is the prevalent option in 2017, but it is quite reasonable to consider that a significant part of VRES will be coupled with storage units at the 2030 time horizon (e.g. coupling of PV systems with batteries, or wind turbines with energy storage, see section 2.4.2), for different purposes: avoid unwanted curtailment and then waste renewable energy, but also better forecast and reduce the uncertainty of the production profile of the combined VRES and storage device (forecast of VRES alone is quite complex).

Option 1: VRES without coupled storage

Considering this option, there is no storage device installed together with the VRES. Also, the intrinsic storage capacity (inertia) of the VRES plants can be reasonably neglected since their time constant would be at best a few seconds, while we consider dynamics at minute/10-minute level in SmartNet. Thus, the dynamical equation (1) is not needed any more, and is replaced by an algebraic constraint for VRES:

$$\boldsymbol{u_{gen}} \le \eta_{gen}\boldsymbol{\xi} \tag{20}$$

where $\boldsymbol{\xi}$ >0 is the power provided by the primary source. The parameter η_{gen} would represent in the simplest possible way the efficiency of the physical conversion process to transform the primary source power into electric power. In the framework of SmartNet, detailed models detailing how the primary source is transformed into electric power are not considered, since they can be quite complex (for PV, it depends on position of the sun, orientation of solar panels, temperature, weather conditions [23], [24]; for wind, many models exist, also depending on the scope [25], [26] ; and for run-of-the-river, it depends on unknowns like rainfall, Geographical area and topology [27], [28], ...) and because the focus is set on the actual electric production. Thus, we can actually rewrite equation (20) as:

$$\boldsymbol{u_{gen}} \le \boldsymbol{\rho} \tag{21}$$

where $\boldsymbol{\rho} = \eta_{gen}\boldsymbol{\xi}$ >0 is the maximum electric power that can be injected into the grid. $\boldsymbol{\rho}$ cannot be controlled because it depends on the availability of the primary resource. The inequality in both equations means that the actual power output of VRES can be controlled to some extent (typically, curtailment), i.e. it is the actual flexibility lever. If VRES cannot be curtailed, then this would be an equality, but then there is no point in modelling such VRES, because they cannot provide any flexibility. Note that the curtailed power of VRES can be expressed as : $\boldsymbol{\zeta} = \boldsymbol{\rho} - \boldsymbol{u_{gen}}$.

Regarding equation (2), u_{gen}^{max} actually represents the rated power of the considered VRES (so, of course, $\boldsymbol{u_{gen}} \le \boldsymbol{\rho} \le u_{gen}^{max}$). A priori, it is assumed that $u_{gen}^{min} = 0$. It is also assumed that no ramping constraints apply for VRES, since the change of generated power is much faster than the 5-10 min time scale that is considered in SmartNet. However, if ramping constraints apply for some VRES technology, equation (5) can be used for that purpose.

Reactive power capabilities depend on the grid-coupling technology: either generators have a power electronic interface, for which there is a (semi-)circular capability (see Figure 4A and equation (9)), either generators have an electrical machine interface, for which the capability can be simplified to a rectangular area (see Figure 4C and equations (10) and (11)). Some generators even have no reactive power flexibility when the coupling is through asynchronous-machine coupling (then a single power factor needs to be considered), even though it is unlikely that new VRES are equipped with such grid coupling technology.

The flexibility cost typically includes several components (see equation (14)). For VRES, there is no indirect cost since curtailment at one time step does not affect the power profile at later time steps (no rebound/pay-back effects, or ramping constraints). Also, there is no discomfort cost since VRES do not directly affect the user. In the other two categories (changes in revenues and operational costs), the flexibility cost of VRES typically includes:

- changes of subsidies and/or sales of electricity. For instance, the VRES owner will lose money by curtailing a wind turbine since he will sell less power and/or lose subsidies. However, this component could disappear in 2030, depending on regulation decisions.
- changes in Operation and Maintenance (O&M) costs: the additional maintenance required to guarantee the exploitation of flexibility (photovoltaic module overheating, more frequent blade control of wind turbine, higher operation of valves in water pipelines) can be considered but it is usually marginal with respect to the changes in subsidies and/or sales of electricity.

Option 2: VRES with coupled storage

In this option, a VRES is coupled with a stationary storage technology, and the combination of the two resources is represented as a single device from the electric network point of view (behind the meter). In this case, the dynamic model described by equation (1) can be used to represent the combined resource dynamic behaviour in a simple way:

$$C\dot{\boldsymbol{x}} = \eta_{load}\boldsymbol{u}_{\boldsymbol{load}} - \frac{\boldsymbol{u}_{\boldsymbol{gen,eq}}}{\boldsymbol{\eta}_{\boldsymbol{gen,eq}}} + \boldsymbol{\rho}_{\boldsymbol{eq}} - \boldsymbol{v} \qquad (22)$$

where

- $\boldsymbol{u}_{\boldsymbol{load}}$ is non-zero only if the combined device (i.e. VRES combined with storage) also consumes electricity from the grid. In case it never happens, then this term can be removed from the equation.
- $\boldsymbol{u}_{\boldsymbol{gen,eq}}$ is the electric active power injected to the grid, coming both directly from the VRES and from the coupled storage.
- $\boldsymbol{\eta}_{\boldsymbol{gen,eq}}$ represents the equivalent conversion efficiency (in bold, because it is a variable depending how the VRES and storage interact). This parameter actually depends on how the combined system is operated. For instance, at a given time, $\boldsymbol{\eta}_{\boldsymbol{gen,eq}}$ is equal to the storage efficiency if all the VRES production (i.e. $\boldsymbol{\rho}$) is sent to the storage device. If the storage resource is not discharging, then $\boldsymbol{\eta}_{\boldsymbol{gen,eq}} = 1$ (note that the conversion efficiency from primary resource to VRES electric production is already taken into account in $\boldsymbol{\rho}$, see description in option 1 paragraph).
- $\boldsymbol{\rho}_{\boldsymbol{eq}}$ represents the equivalent power provided by the primary source to the storage (energy conversion of the VRES already taken into account). This parameter also depends on how the system is operated. For instance, at a given time t, if all the VRES production is directly sent to the grid, then $\boldsymbol{\rho}_{\boldsymbol{eq}} = \boldsymbol{\rho}$. However, if all VRES production is sent to the storage resource, then $\boldsymbol{\rho}_{\boldsymbol{eq}} \leq \boldsymbol{\rho}$ since there is some charging efficiency to transform the electric power from the VRES into the storage (this efficiency is possibly the same as η_{load}).

For other constraints and considerations, please refer to option 1 or to the details of the storage model and constraints in section 2.4.2. Regarding the flexibility cost, flexibility cost of storage need to be included and are described in section 2.4.2. Regarding VRES flexibility costs, it is highly likely that the changes in subsidies, revenues and in maintenance costs will he highly reduced since energy not injected in the network can be stored. However, this is not possible if the storage is full, so the same flexibility cost components as in option 1 can be considered in worst-case situations.

Table 23 in Appendix A represents the main parameters that need to be determined for three main VRES families: wind farms, PV and run-of-the-river hydro power. Ranges of values are provided for each of these parameters, and/or comments are provided to give further insights on the parameterization. The maximum power generation profile, $\boldsymbol{\rho}$, can be represented with time series obtained by forecasting methods [29]–[33], or power generation profiles of some representative days, and/or historical data of forecast and real generation[11]. Of course, weather conditions are often one of the input of these forecasting models.

2.4.2 Stationary storage

The stationary storage category includes many different storage technologies converting electricity into different forms: mechanical, thermal, chemical, electro-chemical and electrical (see Figure 8). The below classification is based on the way to store the electric energy, but other categorizations can be made, based on different criteria/characteristics: e.g. round-trip efficiency, cycle life, self-discharge, energy density, capital and operational costs. The combination of these characteristics helps to define the potential application and business models of each storage technology.

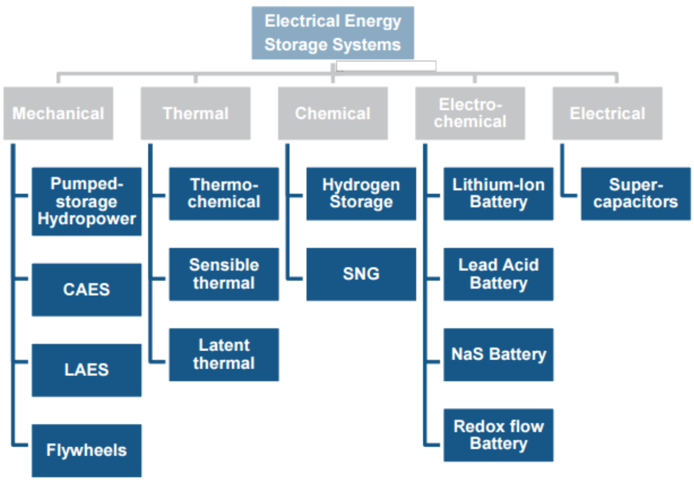

Figure 8: Different categories to store electric energy: general categories and technologies [36]

[11] see for instance TERNA website (http://www.terna.it/en-gb/sistemaelettrico/transparencyreport/generation/forecastandactualgeneration.aspx), or ENTSO-E transparency platform (https://transparency.entsoe.eu/generation/r2/dayAheadGenerationForecastWindAndSolar/show)

In the context of SmartNet, not all storage technologies are fit to provide AS or local services: different technologies can be used for different purposes at different time scales (e.g. see [37], [38]). Also, the reader can refer to chapter 3, where the technical capabilities of DER families to provide various AS and local services are described, also depending on the grid coupling technology. Predicting the penetration rate of these technologies in the time horizon considered by SmartNet (2030), their maturity and price, is difficult. However, as indicated in [39] and seen in Figure 9, it is reasonable to assume that the technologies which are still under a R&D phase (i.e. Hydrogen, Synthetic Natural gas, SMES and Supercapacitor) now will not be competitive with other technologies to be widely deployed in 2030.

In the following, the model is parametrized for four technologies that are believed to be widely used in 2030 for providing AS and local services to SOs: pumped-hydro energy storage (PHES), electro-chemical batteries, Compressed Air Energy Storage (CAES) and flywheels. However, the generic model itself can apply to all technologies.

Regarding the model, the state of charge (SoC) directly refers to the term $\boldsymbol{x}$ of equation (1) in section 2.3.1. The self-discharge term $\boldsymbol{v}$ can be represented in many ways, and can be quite complex to describe. For instance, it can be expressed as a linear dependence of the state variable $\boldsymbol{x}$ [4]. Here, for the sake of simplicity, it is assumed that it is a constant: $\boldsymbol{v} = v$, to be parametrized for each technology (see below). Regarding the provided or demanded power by external processes $\boldsymbol{\xi}$, it can:

1. either be removed (or set to 0) if the storage is only coupled to the grid and not to either loads or local generators (behind-the-meter)
2. be kept in the equation provided
    a. the storage can be used to satisfy local demand (e.g. auto-consumption)
    b. the storage can be charged by local generation (e.g. combination of PV and storage, or water filling a reservoir of hydro-pumped storage). This subcase has been described in section 2.4.1.

In the latter case, the variable $\boldsymbol{\xi}$ should be explicated and or at least a power profile should be given depending on the use case. In this deliverable, $\boldsymbol{\xi}$ is not considered in the parametrization: however, the equation can still be used if the user provides the expression of $\boldsymbol{\xi}$ (e.g. the power profile of a PV panel).

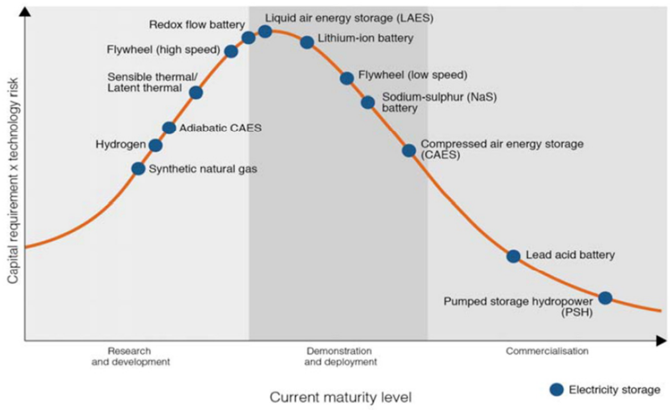

Figure 9: Maturity of energy storage technologies [39]

In order to ensure that charging and discharging cannot happen at the same time (e.g. a battery), an additional constraint can be added (for technologies for which charging and discharging processes are different, like for PHES, this constraint is not needed):

$$\boldsymbol{u_{load}} \cdot \boldsymbol{u_{gen}} = 0 \tag{23}$$

Also, depending on the use of storage for other applications, additional (tighter) constraints (with respect to equation (4)) on the SoC can also be specified:

$$SoC_{min} \leq \boldsymbol{x} \leq SoC_{max} \tag{24}$$

where SoC_{min} and SoC_{max} are the minimum and maximum SoC [%] by the storage owner. In the following, it is considered that $SoC_{min} = 0$ and SoC_{max}=100 % (then, equations (4) and (24) are identical), unless otherwise mentioned. It is also possible to penalize and/or prevent a too large number of cycles in a given period of simulation (see [40]).

Regarding the min charging and discharging power u_{load}^{min} and u_{gen}^{min}, these parameters are assumed to be equal to 0, unless otherwise stated. Ramping constraints are most of the time negligible for the type of AS to be considered, but indicative values are mentioned in Table 24 (Appendix A).

The ability of the storage system to provide reactive power is directly related to the grid-coupling technologies used to connect the storage to the network, resulting then in different capabilities (see section 2.3.2) in terms of reactive power. Grid coupling technologies for storage include inverters (circular capability), rotating machine direct coupling (usually simplified to rectangular capability) or back-to-back converter (circular capability).

Regarding flexibility cost, in line with the different components of the flexibility cost described in section 2.3.4, for stationary storage:

- No discomfort cost is considered since there is no loss of comfort for users of storage.
- Change of operational costs and revenues can include:

- O&M costs (only if providing flexibility implies a change in these costs).
- Change of electricity costs/revenues which can apply in the following cases:
  - Potentially varying prices if tariffs are non-firm for the DER owner (see section 2.3.4),
  - Assuming the storage must reach some SoC similar to the one of the baseline at some time t, there can be a change in total consumption/generation quantity with respect to baseline due to the charging and discharging efficiencies (in other words, the cost of round-trip efficiency).
  - However for the sake of simplicity, the full description of these changes in electricity cost/revenues is neglected in the following, since as shown in Figure 7, it does not affect the flexibility cost of the aggregator.
- Indirect cost: the same situation as for changes in electricity costs and/or revenues can apply, but with the rebound/payback effect occurring at least partly after the time window of flexibility activation. In this case, it affects the flexibility cost of the aggregator [3].
- Additionally, CAPEX can also be considered in the flexibility cost, under the form of levelized cost of energy (LCOE) for instance, in case the stationary storage device is dedicated to services provisions. However, the consideration of fixed costs depends on the market clearing pricing rule used on a market: if a pay-as-bid approach is used, it makes sense to include this cost, but this is less obvious in the case of a marginal pricing approach. . However, as discussed in section 2.3.4 on page 25, to ensure a level playing field for storage in the AS markets, no CAPEX is considered.

Table 24 (Appendix A) gathers ranges of values for the model parameters for different storage technologies. These values are needed by the aggregator in order to assess the state of the DER, the potential flexibility available at any time, as well as the cost of providing flexibility with this resource.

2.4.3 Electrical Vehicles

Electrical vehicles (EVs) are considered as a separate category from stationary storage (see section 2.4.2). Even though the battery technology is basically the same for stationary or mobile applications, EVs have specific additional constraints (e.g. the battery is not connected to the grid all the time and the battery is primarily used to drive) that we tackle in this section. Among the family of electric vehicles (e.g. see [41]), we include all electric vehicles which can be charged by connecting them to the electric grid, i.e. plug-in electric vehicles [42] . This includes the followings types:

- BEV: Battery electric vehicles (also known as all-electric vehicle (AEV)), which run only on electricity (Batteries and electric motors). Batteries are charged only through the grid (and possibly by regenerative braking).

- PHEV: plug-in hybrid electric vehicles, which also have an ICE (internal combustion engine), on top of the electric motor, to power the car. These cars can switch to the ICE when the battery is depleted. Battery is charged by plugging it to the grid and possibly by regenerative braking.
- REEV: range-extended electric vehicles, which differ from the PHEV by the fact that the ICE is more a backup system, used to charge the battery, in order to extend the range of the vehicle on some occasions.

Note that both hybrid electric vehicles (i.e. where the battery is only charged by regenerative braking) and fuel cell electric vehicles [41] are not considered since they are never plugged in to the electric grid and thus cannot provide services to the grid.

All EVs can technically provide grid-to-vehicle (G2V) services to the power system by modulating their charging power consumption pattern. Part of the EVs could also provide vehicle-to-grid (V2G) services to the grid by also discharging power into the grid, similar to a stationary battery.

From a modelling perspective, the dynamic evolution of the SoC can also be described by equation (1). Equations (2) and (3) are modified as follows, to account for the fact that an EV is not always plugged-in.

$$0 \leq u_{gen}^{min}(1-\boldsymbol{k_t}) \leq \boldsymbol{u_{gen}} \leq u_{gen}^{max}(1-\boldsymbol{k_t}) \tag{25}$$

$$0 \leq u_{load}^{min}(1-\boldsymbol{k_t}) \leq \boldsymbol{u_{load}} \leq u_{load}^{max}(1-\boldsymbol{k_t}) \tag{26}$$

where $\boldsymbol{k_t}$ is a binary variable which represents the driving state of the vehicle: 1 if the vehicle is not plugged in (e.g. because it is driven), and 0 otherwise (e.g. red line in Figure 10). We assume that it is connected to the grid when the vehicle is not driven. Also, in case V2G is not technically possible, then the parameters $\mathrm{u_{gen}^{min}}$ and $\mathrm{u_{gen}^{max}}$ are both equal to 0.

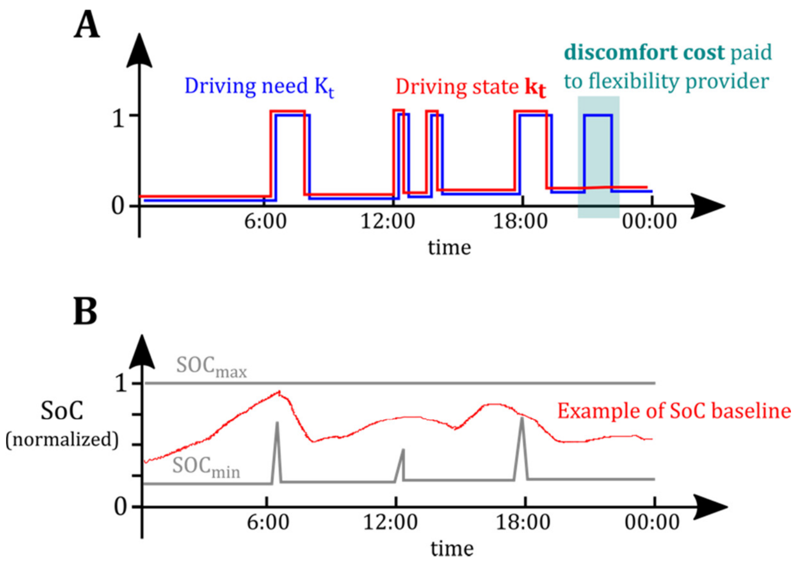

Figure 10: ***(A)*** Example of driving need K_t, driving state $\boldsymbol{k_t}$ and associated discomfort cost **(B)** Example of SoC of an EV throughout an entire day.

The driving state $\boldsymbol{k_t}$ is usually equal to the driving need parameter, K_t, which is a binary parameter (evolving over time, e.g. blue curve in Figure 10) representing the willingness to drive or not at that time, and can be enforced by setting $\boldsymbol{k_t} = K_t$. Alternatively, the EV owner can allow his need not to be satisfied , i.e. $\boldsymbol{k_t} \leq K_t$, provided that he is financially compensated for some discomfort cost. The discomfort cost for a specific time step, from t_1 to t_2, can be expressed as:

$$discomfort\ cost\ from\ t_1 \text{to}\ t_2 = \int_{t_1}^{t_2} \phi(t) \cdot (K_t - \boldsymbol{k_t})\ \mathrm{dt} \qquad [\,€] \qquad (27)$$

where ϕ(t) represents the discomfort cost set by the EV owner [€/hour]. As indicated in equation (1), the EV battery is also exposed to self-discharge losses $\boldsymbol{v}$, as described for stationary batteries in section 2.4.3. Regarding the demanded power variable **ξ**, it can be expressed as:

$$\boldsymbol{\xi} = -\boldsymbol{k_t} \cdot (v_{avg} \cdot \mu) \qquad (28)$$

where $\boldsymbol{v_{avg}}$ represents the average speed of the EV when driving [km/h] and **μ** represents the average driving efficiency of the EV battery [kWh/km]. The charging of the battery through regenerative braking can be simply modelled by including in the driving efficiency parameter (increasing it with respect to the situation where regenerative braking is not possible). Also, no ramping constraints apply at the time scale considered, either for charging or discharging the battery. Constraints on the battery SoC can also be specified: (1) for technical reasons and, (2) to ensure that the battery SoC is high enough at some point in time to allow the EV to make the driving travel planned by the EV user.

$$SoC_{min} \leq \boldsymbol{x} \leq SoC_{max} \qquad (29)$$

Typically, $SoC_{min}$and SoC_{max} have fixed values as for reason (1), while more restrictive values (time-varying) may apply for SoC_{min} as for reason (2), depending on the upcoming planned trips (see Figure 10B). SoC_{min} is likely to be more restrictive in case of a BEV, while it could be less constrained for PHEV and REEV since backup fuels can allow to drive the EV even when the battery is depleted.

Regarding the reactive power, circular (or half-circular) capability can be considered [43], [44] (see section 2.3.2), only when the EV is connected to the grid of course.

The cost of providing flexibility includes:

- the discomfort cost, as described in equation (27)
- the change of operational costs/revenues can include *additional O&M costs* (compared to the case where no ancillary services are provided), and changes in electricity consumption, as explained in more detail in the section dedicated to stationary storage (section 2.4.2).
- the indirect cost: similar to description in section 2.4.2

However, the capital cost is not included since it is assumed that the investment cost is supported by the user for its primary goal, i.e. driving the car [45].

Table 25 in Appendix A gathers values, ranges of values or information about all parameters of the individual EV model described above.

2.4.4 Conventional generators

In this section, the flexible distributed conventional/backup generators are described. They mainly include thermal generators running on fossil fuels (coal, gas, oil), but they can also include medium or large hydropower plants (for which the power output is controllable, otherwise, it is considered in the VRES, in section 2.4.1).

Conventional/back-up generators do not include a storage process and thus equation (1) can be simply expressed as:

$$\boldsymbol{u_{gen}} = \eta_{gen}\boldsymbol{\xi} \tag{30}$$

where η_{gen} is the generator efficiency to convert the fuel energy into electric power and $\boldsymbol{\xi}$ represents the fuel power as an input to the generator (in this section, $\boldsymbol{\xi}$ is thus a controllable/dispatchable variable).

Conventional generators have typical technical minimum (u_{gen}^{min}) and maximum (u_{gen}^{max}) active power limits (similar to equation (2)) when the generators are ON:

$$0 \leq u_{gen}^{min} \cdot \boldsymbol{y_t} \leq \boldsymbol{u_{gen}} \leq u_{gen}^{max} \cdot \boldsymbol{y_t} \tag{31}$$

where $\boldsymbol{y_t}$ is a time-varying binary variable describing whether the generator is ON ($\boldsymbol{y_t} = 1$) or ($\boldsymbol{y_t} = 0$) ; it is a decision variable, like $\boldsymbol{u_{gen}}$. When they are operating (state ON), conventional generators are also subject to ramping-up ($r_{gen}^{max} > 0$) and ramping down constraints ($r_{gen}^{min} < 0$), similar to equation (5):

$$r_{gen}^{min} \cdot \boldsymbol{y_t} \leq \boldsymbol{\dot{u}_{gen}} \leq r_{gen}^{max} \cdot \boldsymbol{y_t} \tag{32}$$

For start-up and shut-down situations, different ramping constraints may apply: maximum ramping up (resp. down) at start-up (resp. shut-down) can be defined by the parameter r_{gen}^{SU} (resp. r_{gen}^{SD}) for a given period of time after start-up (resp. before shut-down) of the generator. One way to model these constraints is to modify r_{gen}^{max} (resp. r_{gen}^{min}) in equation (32), by r_{gen}^{SU} (resp. r_{gen}^{SD}) for a time period Δt_{SU} (resp. Δt_{SD}) after start-up (resp. before shut-down).

$$r_{gen}^{SD} \leq \boldsymbol{\dot{u}_{gen}} \leq r_{gen}^{SU} \tag{33}$$

Typical values of these parameters are provided in Table 26. Regarding reactive power, conventional (synchronous) generators typically have a complex active-reactive power curve/area, which can be approximated by rectangular capability, as shown in Figure 11.

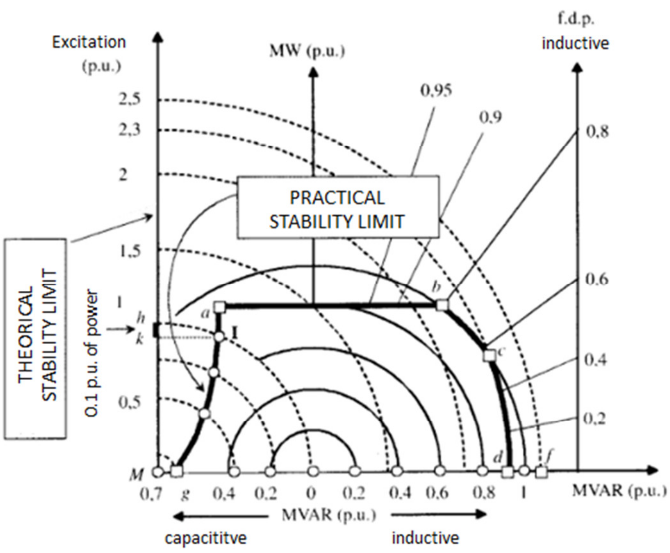

Figure 11: Operations limits of a synchronous conventional generator [46]

Additional constraints compared to the generic model can also be considered. Two of them relate to the minimum time that a generator needs to be operating, denoted MO, and to the minimum time it needs to remain stopped, denoted MS. This is motivated by the minimization of the unnecessary thermal cycles in turbines, generators, boilers. These constraints can be written as:

$$\boldsymbol{D_{ON}}(t) \stackrel{\text{def}}{=} \int_{t_{SU}}^{t} \boldsymbol{y_t}(\tau)\, d\tau \geq MO \tag{34}$$

$$\boldsymbol{D_{OFF}}(t) \stackrel{\text{def}}{=} \int_{t_{SD}}^{t} (1 - \boldsymbol{y_t}(\tau))\, d\tau \geq MS \tag{35}$$

where t_{SU} and t_{SD} are the latest times at which start-up and shut-down occurred (to be reset after each change). These constraints are expressed in continuous time to be consistent for the chosen modelling approach. However, an aggregator would typically discretize these constraints to take them into account into an optimization problem.

Different costs components can affect the flexibility cost:

- the start-up cost, SUC, is considered when the generator is switched on to provide flexibility. This cost represents the cost of connecting the generator again after some time stopped (cold start): in this case, some energy is spent just to warm the generator again. This cost is much lower if the generator is still warm when switching it on (warm start).
- the shut-down cost, SDC, is considered when the generator is switched off to provide flexibility. This cost represents the fuel waste and labour to decouple the power plant. This cost is typically much lower than the start-up cost.
- the changes in the production cost, $\Delta op.costs$, which include:

$$\Delta op.costs = \frac{(FC + r_{CO2} \cdot \lambda_{CO2})}{\eta_{gen}} + VOM \tag{36}$$

- the fuel costs, *FC*: when they are expressed in costs per unit of energy in the fuel, then
- the CO2 emissions costs, define by the cost of one ton of CO2, denoted λ_{CO2} [€/ton CO2], and the quantity of CO2 produced for the combustion of each ton of fuel, denoted r_{CO2} [ton CO2/ton fuel].
- the variable O&M costs, denoted VOM [€/MWh]

Note that the generator efficiency η_{gen} depends on the load factor, as shown for some typical generator technologies in Figure 12.

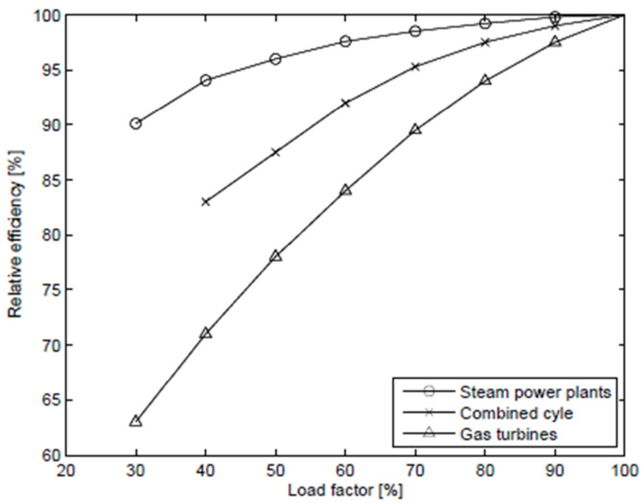

Figure 12: Generator relative efficiency vs load factor [47]

Table 26 (Appendix A) gathers values, ranges of values or information about all parameters of the conventional generators model described above.

2.4.5 Combined Heat and Power

CHP plants generate both electricity and heat from a central process: electricity is then used behind-the-meter, or injected into the power grid, while heat is generated for on-site (residential, industrial) purposes and sometimes to inject heat in a district-heating network. CHPs can be classified in three main types [48]:

- *Industrial CHP*: heat is produced for an industrial process needs and electricity generation can be seen as a by-product.
- *Residential CHP used for district heating*: the heat demand follows some seasonal patterns.
- *Micro-CHP*: used at building level, for heating purposes (<15 kW, [49])

Most of the time, CHP production is driven by the heat demand [48] since there is often less flexibility in heat demand or no alternative way to procure the heat, while for electricity, the grid can more easily complement the local electricity production. Thus, CHPs are generally quite inflexible. Flexibility can be largely increased 1) if the electricity production can be technically decoupled to some extent to the heat production by technology improvements [50] and/or 2) if the heat production becomes flexible (e.g. by having a heat storage system), by decoupling the heat production of the CHP and the (inflexible) heat demand and/or 3) by making the heat demand (more) flexible (e.g. use of back-up boilers, flexibility of end-users in their heat demand, alternative heat generators feeding a district heating system).

Most common technologies commercially available to run CHP are internal combustion engines (ICE), fuel cells (FC), steam turbines (ST) and gas turbines (GT), as well as combined-cycle gas turbines (CCGT) (see Figure 13). FCs are used as micro-CHP units and are becoming more and more available. Steam and combustion turbines are incorporated as industrial and district heating CHPs, while micro-turbines are used in residential and commercial CHP applications. Various types of fuels can be used, as highlighted in Figure 13. In 2013, the fuel mix was roughly 45 % for natural gas, 21 % for solid fossil fuels, 18 % from renewable sources (biogas, biomass, biofuels), and the rest from other fuels [51].

Regarding the modelling the following assumptions are taken: the (electric) storage is not considered (i.e. thermal storage is considered, see equation (40), but just to decouple the heat demand and heat production of the CHP, not to generate electricity in the grid), there is no electric consumption from the grid, and both heat and power are generated by the CHP. Accordingly, equation (1) is simplified and a second equation is added to represent the heat production as follows:

$$\boldsymbol{u_{gen,elec}} = \eta_{gen,elec}\boldsymbol{\xi_{fuel}} \tag{37}$$

$$\boldsymbol{u_{gen,heat}} = \eta_{gen,heat}\boldsymbol{\xi_{fuel}} \tag{38}$$

where $\boldsymbol{u_{gen,elec}}$ (resp. $\boldsymbol{u_{gen,elec}}$) is the electric (resp. heat) power generated by the CHP, using input power from fuel $\boldsymbol{\xi_{fuel}}$, with an electric (resp. heat) efficiency $\eta_{gen,elec}$ (resp. $\eta_{gen,heat}$). Note that the CHP can not modulate the output electric power in input without modulating the output heat power. These efficiencies are linked to each other:

$$\eta_{gen,total} = \eta_{gen,heat} + \eta_{gen,elec} < 1 \tag{39}$$

where $\eta_{gen,total}$ represents the total efficiency of the CHP (i.e. proportion of fuel energy transformed into recovered heat and electricity). Ranges of values for these efficiencies are provided in Table 27 in Appendix A.

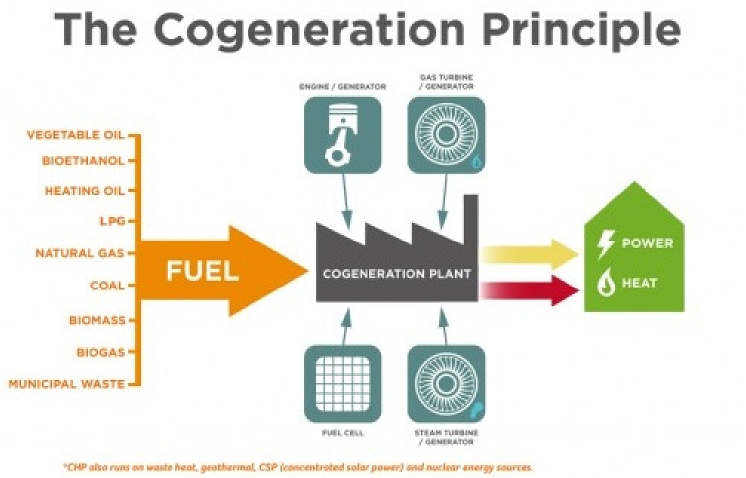

Figure 13: CHP principle: many possible fuels and technologies. Figure from [51]

Figure 14 represents this production of both heat and electric power from the fuel by the CHP. In the following, it is assumed that all the electric power is sent to the power grid, while in practice, there is always a specific, potentially flexible, part of the produced electricity which is used on-site, and not injected to the grid (auto-consumption).

In the model, it is assumed that heat storage is installed next to the CHPs (see Figure 14), in order to allow the CHP to be flexible in the provision of electric power to the grid. This is because the heat demand $\boldsymbol{\xi_{heat}}$ is usually assumed to be inflexible and supposed to be known: $\boldsymbol{\xi_{heat}} = \xi_{heat}$ (where ξ_{heat} represents the heat demand typical for the application considered). Alternatively, it could also be assumed that the heat power demand, $\boldsymbol{\xi_{heat}}$, is flexible to some extent: for instance, $\xi_{heat}^{min} \leq \boldsymbol{\xi_{heat}} \leq \xi_{heat}^{max}$.The heat storage dynamics can be simply written as:

$$C_{heat}\boldsymbol{x_{heat}} = u_{gen,heat} - \boldsymbol{\xi_{heat}} - \boldsymbol{v_{heat}} \tag{40}$$

where C_{heat} is the capacity of the heat storage [kWh], $0 \leq \boldsymbol{x_{heat}} \leq 1$ is the normalized heat storage level (variable, no unit) and $\boldsymbol{v_{heat}}$ is the self-discharge heat loss. As an example, $\boldsymbol{v_{heat}} = v_{cst,heat}\boldsymbol{x_{heat}}$ where $v_{cst,heat}$ represents the constant self-discharge losses, making $\boldsymbol{v_{heat}}$ proportional to the heat storage level (e.g. $v_{cst,heat}$=10 %/hour). Note that it is implicitly assumed in equation (40) that there are no other sources of heat to "charge" the heat storage (while in practice, other heat boilers or other heat sources could also fill the heat storage).

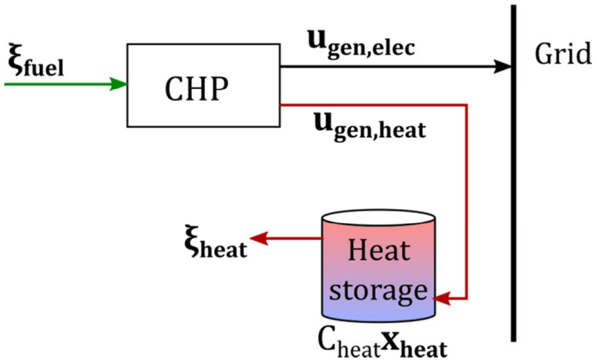

Figure 14: Basic CHP setup assumed in the modelling, with heat storage

The heat storage level is restricted to minimum (C_{heat}^{min}) and maximum (C_{heat}^{max}) values:

$$C_{heat}^{min} \leq C_{heat}\boldsymbol{x_{heat}} \leq C_{heat}^{max} \tag{41}$$

Regarding reactive power, the CHP capabilities depend on the grid-connection type: they can either have rectangular (synchronous generator (SG)), semi-circular (inverter connection (Inv)) or fixed power factor (induction generator (IG)) capabilities (see section 2.3.2).

Similarly to conventional generators, constraints on minimum ($\mathrm{u}_{\mathrm{gen}}^{\mathrm{min}}$) and maximum ($\mathrm{u}_{\mathrm{gen}}^{\mathrm{max}}$) active power limits apply when the CHPs are operating (see equation (31)). For fuel cells and turbines-based CHPs, ramping constraints can also apply [52]–[54] (as described by equation (32) in section 2.4.4).

The cost of providing flexibility for CHP includes the following components:

- a discomfort cost: for instance, a user could allow the heat demand not to be satisfied, but that he is remunerated for the discomfort.
- a change in subsidies ($\lambda_{subsidies}$): in some countries, CHPs are favoured (due to their high efficiency) and receive subsidies to produce.
- fuel costs (λ_{FC}): similar to what has been described for conventional generators
- CO2 emissions costs (λ_{CO2}): similar to what has been described for conventional generators
- variable O&M costs (VOM): similar to what has been described for conventional generators
- start-up (denoted *SUC*) and shut-down (denoted *SDC*) costs must also been considered (except for ICE CHP for which start-up and whut-down is quite fast and thus these costs can be neglected [52], [53]), as described in section 2.4.4

Table 27 in Appendix A gathers values, ranges of values or information about all parameters of the CHP model described above.

2.4.6 Thermostatically Controlled Loads

TCLs represent any load whose electric consumption is driven by a temperature setpoint signal. They include among other the heating and cooling (HVAC[12]) systems required to heat and/or cool buildings using electricity (e.g. using heat pumps, electric heaters), refrigerators, freezers (both household and commercial size) and electric water heaters (i.e. electric boilers). In the following, two generic TCLs models are described: in a first time an electric boiler model is represented using the formalism described in section 2.3.1 (note that a similar simplified model can be used for refrigerators and freezers). Then, a second-order generic model of a generic thermal system is described, where temperatures are explicit variables in the model; this model can be used to represent any HVAC system.

Model 1: Electric boiler model

For a simple electric boiler, equation (1) can be reduced to:

$$C\dot{\boldsymbol{x}} = \eta_{load}\boldsymbol{u_{load}} + \boldsymbol{\xi} - \boldsymbol{v} \tag{42}$$

where $\boldsymbol{\xi} \leq 0$ represents the heat demand (i.e. heat extraction from the buffer due to user needs, not due to losses), while $\boldsymbol{v}$ represents the storage losses. This model can be further detailed under some assumptions: content of the buffer is liquid water, fixed density of water (i.e. 1 kg/m^3), the specific heat of water is assumed to be constant: $\rho_{water}^{heat} = 4186\, J/(K \cdot kg)$, the reference temperature versus which energy levels are calculated is 0° C and the mixing of water in the tank is assumed to be instantaneous and perfect. Under these assumptions, the maximum capacity of the heat storage C can be expressed as:

$$C = \rho_{water}^{heat} \cdot V \cdot T_{max} \tag{43}$$

where V is the volume of the buffer and T_{max} is the maximum allowed temperature of the boiler. Ranges of values for domestic boilers are provided in Table 28 (Appendix A). The losses $\boldsymbol{v}$ of the buffer are assumed to be linear and proportional to the temperature difference between the boiler temperature, $\boldsymbol{T_{boiler}}$, and the external temperature, T_a, surrounding the buffer:

$$\boldsymbol{v} = -A \cdot \mu_{loss} \cdot \left(T_a - \underbrace{C\boldsymbol{x} / \rho_{water}^{heat} \cdot V}_{\boldsymbol{T_{boiler}}} \right) \tag{44}$$

where A is the total surface of the buffer [m^2] and μ_{loss} is the heat loss coefficient of the buffer [W/(m^2.°C)]. Similar to what has been described in section 2.4.5, the heat demand $\boldsymbol{\xi}$ is assumed to be inflexible and supposed to be known: $\boldsymbol{\xi} = \xi$ (where ξ represents the heat demand typical for the application considered). Equations (3) and (4) also apply to describe the minimum and maximum active power consumption as well as the minimum and maximum state of charge of the buffer (in terms of

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[12] Note that HVAC also includes ventilation. In case ventilation is not temperature driven, but is still flexible, then it would be modelled as a curtailable load (see section 2.4.8).

energy content). In terms of reactive power, the heat is assumed to be supplied to the buffer through a perfect resistor, hence the reactive power consumption $\boldsymbol{q_{grid}}$ of the boiler is 0 (i.e. the power factor is equal to 1), meaning that boilers have no reactive power flexibility to offer. Also, no ramping constraints (see equation (6)) apply for TCLs. Table 28 presents ranges of values for the different parameters of the above boiler model.

Model 2: Second-order equivalent thermal network model

In order to model the thermal behaviour of a generic thermal system[13] (e.g. a building, a swimming pool, a supermarket freezer), a grey-box equivalent thermal network model is used (see [24], [55], [56]). The general idea is to represent the thermal model in a less simplified way (depending on the number of internal variables used to characterise the thermal system), using lumped parameters to represent the thermal resistances (i.e. heat transfer coefficients) and capacitances (i.e. thermal capacities of the thermal masses).

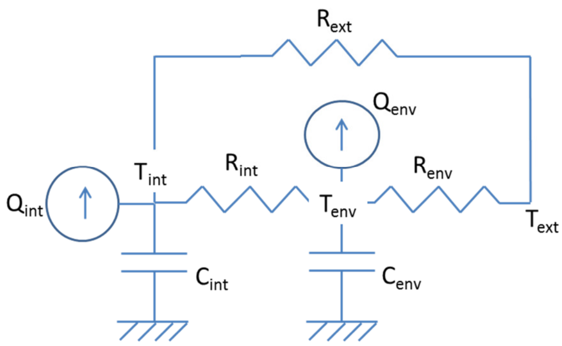

Figure 15: Example of an equivalent thermal network second-order model (Figure from [3])

Although first-order [54] and third-order [53] models exist, a second-order model (2C3R, *see Figure 15)* is selected because, according to [22], *"lower-order models are sufficient to accurately predict the thermal response of a building on time-scales of 15 min up to a week. (...) More precise, a 2nd-order model that distinguishes between the fast thermal dynamics of the indoor air and the slow dynamics of the structural thermal mass, is found to be adequate for short-term predictions. When the building is equipped with floor heating, the model may even be reduced to a 1st-order model, due to the fact that the floor itself acts as a low-pass filter smoothing out the temperature variations".* Even though a second-order model is a good choice when buildings are involved, first-order models are sometimes sufficient for other types of TCLs: in the following, the first-order model is not described, but using an appropriate parametrization, the second-order model can be reduced to a first order model.

Using a second-order model, it is assumed in the following that there is an internal mass (e.g. the air in a house, the water in a boiler or swimming pool, the content of a fridge) which needs to be heated and/or

[13] in this subsection, the model elaborated does not fit perfectly the generic model described in section 2.3.1 but it is an extended modification, more suitable for TCLs

cooled, and an envelope mass (e.g. the walls and windows of a building, the tank of the boiler) surrounding the internal mass which insulates it from the external environment. The thermal equations describing the dynamics of the internal and envelope temperature can be written as:

$$C_{int}\dot{\boldsymbol{T}}_{\boldsymbol{int}} = \boldsymbol{Q}_{\boldsymbol{int}} + \frac{1}{R_{int}}(\boldsymbol{T}_{\boldsymbol{env}} - \boldsymbol{T}_{\boldsymbol{int}}) + \frac{1}{R_{ext}}(T_{ext} - \boldsymbol{T}_{\boldsymbol{int}}) \tag{45}$$

$$C_{env}\dot{\boldsymbol{T}}_{\boldsymbol{env}} = \boldsymbol{Q}_{\boldsymbol{env}} + \frac{1}{R_{int}}(\boldsymbol{T}_{\boldsymbol{int}} - \boldsymbol{T}_{\boldsymbol{env}}) + \frac{1}{R_{env}}(T_{ext} - \boldsymbol{T}_{\boldsymbol{env}}) \tag{46}$$

where C_{int} (resp. C_{env}) is the thermal capacity of the internal (resp. envelope) mass (in J/°C), and R_{int} (resp. R_{ext} and R_{env}) is the thermal resistance (in W/°C) between the internal mass and the envelope (resp. between the internal mass and the exterior, and between the envelope and the exterior), as indicated in Figure 15. $\boldsymbol{T}_{\boldsymbol{int}}$ (resp. $\boldsymbol{T}_{\boldsymbol{env}}$ and T_{ext}) is the temperature [°C] of the internal mass (resp. the envelope and the external environment). Finally, $\boldsymbol{Q}_{\boldsymbol{int}}$ and $\boldsymbol{Q}_{\boldsymbol{env}}$ are the internal heating/cooling gains [W] of the internal mass and the envelope, representing the sum of all input and output heat power. As examples, for HVAC systems, $\boldsymbol{Q}_{\boldsymbol{int}}$ includes heat generated by building occupants, household appliances and the heat/cold generated by the HVAC itself. For a boiler, it includes heat input from the electric resistance and also the heat loss due to usage of the water by the building occupants/systems. These gains can be further detailed into two components: the gains coming from the heating/cooling system and the heat gains ($Q_{int,gains}$ and $Q_{env,gains}$), most of the time not controllable:

$$Q_{int} = Q_{int,gains} \pm (1 - f_{rad}) \cdot \eta_{el,thermal} \cdot \boldsymbol{u}_{\boldsymbol{load}} \tag{47}$$

$$Q_{env} = Q_{env,gains} \pm f_{rad} \cdot \eta_{el,thermal} \cdot \boldsymbol{u}_{\boldsymbol{load}} \tag{48}$$

where $\boldsymbol{u}_{\boldsymbol{load}}$ is the electric power consumption of the TCL. The $\pm$ sign in the equations depends on whether heating ('+' sign) or cooling ('-' sign) applies. $\eta_{el,thermal}$ represents the electric to thermal power conversion factor: as an example, $\eta_{el,thermal}$ would be equal to 1 for an electric boiler while for heat pumps (more commonly called coefficient of performance (COP)), it would depend on many factors (e.g. technology, weather conditions, building heating technology,...), but is typically between 1 and 5, for heating and slightly less for cooling [57]. f_{rad} represents the heating distribution factor ($0 \leq f_{rad} \leq 1$), specifying the proportion of heat provided by the heating/cooling device going directly to the internal mass and to the envelope (see [55]).

Minimum and maximum power consumption constraints, as described by equation (3)), also apply to TCLs. However, no ramping constraints are considered (TCLs are assumed to be able to reach their rated power nearly instantaneously). Regarding reactive power, it also depends on the application, but a fixed power factor can be considered.

Typically, minimum (T_{int}^{min}) and maximum (T_{int}^{max}) constraints on the internal mass temperature, $\boldsymbol{T}_{\boldsymbol{int}}$, apply:

$$T_{int}^{min} \leq \boldsymbol{T_{int}} \leq T_{int}^{max} \tag{49}$$

These minimum and maximum temperatures depend on the application, and can also vary over time, depending on user requirements (e.g. T_{int}^{min} might be lower during the day when nobody is home, while it will be close to the desired setpoint when occupants are there, in the evening).

As an example of this generic model, a heat pump coupled to a second-order building model is considered: the envelope consists in the walls and windows and the internal mass consists in the air in the room. In particular, the losses between the indoor air and the external environment are assumed to be ventilation losses (others are the losses between air and walls, and between walls and outdoor). Also, it is assumed that the heating power provided by the heat pump is partially injected in the walls and partially in the air (i.e. $0 < f_{rad} < 1$). In this scenario, $Q_{int,gains}$ represents the heat generated by occupants of the building and loads inside the house. For the envelope (walls and windows), it is assumed that $Q_{env,gains} = gA \cdot SR$, where gA represents the solar gain factor (in m^2, an average surface number of the building calibrated to match the increase in temperature in a building as a result of solar radiation, see [58]; this number is building specifics (isolation, materials)). SR represents the solar radiation [W/m^2], that is highly dependent on weather condition, season, and location. Table 29 (Appendix A) shows (ranges of) values for the different parameters of the above heat pump and second-order building model.

Flexibility cost

The cost of providing flexibility for TCLs includes the following components:

- possibly a discomfort cost (see Table 30 in Appendix A for a thorough discussion of discomfort costs for TCLs): for instance, a user could allow the heat demand not to be satisfied (in the boiler example) or that the min and max temperatures constraints (equation (49)) are removed, but that he is remunerated for the discomfort (as an example, see Figure 7B).
- changes in operational cost due to the change in electricity consumption due to the situation where no flexibility is provided (baseline situation, see Figure 7A, and related text in section 2.3.4). However, no changes in O&M costs are considered.
- an indirect cost due to the additional electricity consumption [22] due to the rebound effect and the modification from the baseline at the time(s) of the rebound effect (see Figure 7A and more details in section 2.3.4).

2.4.7 Shiftable loads

Flexible loads are generally split into two main categories: shiftable loads (described in this section) and curtailable loads (described in upcoming section). Loads are defined as shiftable when (part of) the electric consumption can be shifted in time (earlier and/or later), compared to the baseline behaviour (e.g. see Figure 6B and Figure 16); they are curtailable when the electric consumption can be decreased or increased (at the time of the flexibility provision) without any impact on the earlier or later electric consumption of the load. Apart from TCLs (which are also a specific category of shiftable loads, but that we have treated previously in section 2.4.6), shiftable loads can be found in some industrial processes and in some household appliances.

Industrial processes (such as goods production, mining or quarrying) have a significant demand response (DR) potential while having high power intensity [59]. They are considered as shiftable loads (in contrast to curtailable) because of the payback/rebound effect that is observed. For instance, if fewer goods are generated during the AS provision time slot due to reduced electricity consumption on a machine, these need to be produced later (or earlier), which also implies a change in the electricity consumption (see Figure 16B for example). In the extreme case where the loss is never recovered or recovered much later, the flexibility provided relates more to load curtailment (see section 2.4.8). In this case the flexibility provider would likely claim a much higher flexibility cost (since some process production would never be met, which implies a loss of revenues for the company).

In general, household loads can be grouped into TCLs and non-TCLs. The latter includes for instance lighting, consumer electronics, cooking and wet appliances, which are tightly tied with the occupants' activities and comfort. Among the aforementioned loads, a majority (e.g. cooking, consumer electronics) is not flexible at all (or they could be, but in load curtailment section). However, wet appliances (i.e. washing machines, tumble dryers, dish-washers) have a significant shifting potential (European consumers accept on average 6 hours of shifting for those devices according to [60]).

Modelling industrial processes can turn out to be complex and very dependent on each process industry (and even each company). In fact they are quite interlinked with scheduling problem, balance and operational constraints, timing and energy balance (e.g. see [61] for a scheduling problem targeting minimization of energy cost). On the contrary, wet appliances constraints are relatively generic. In the following, a model for load shifting is described and then pragmatic extensions/simplifications are discussed for both wet appliances and industrial processes.

Shiftable loads are of course subject to minimum and maximum power consumption (represented by grey line in Figure 16B and Figure 16D), as described by equation (3). Ramping constraints (equation (6) can potentially apply for some industrial processes. In terms of reactive power, a fixed power factor can be assumed for both wet appliances and industrial processes [62]–[64], although industrial loads are usually using power factor correction to get a $cos\varphi$ closer to 1 [62], [63]. In a generic way, an energy constraint can be considered, stating that the load energy consumption in a time interval specified by the user must lie between a minimum, E_{min} [kWh], and a maximum, E_{max} [kWh], value:

$$E_{min} \leq \int_{t_{init}}^{t_{end}} \boldsymbol{u_{load}}(\tau) d\tau \leq E_{max} \tag{50}$$

where t_{init} and t_{end} represent the time bounds during which the flexibility can be provided and during which the energy constraints (50) must be satisfied (see Figure 16). These two parameters are set by the user (e.g. t_{init} represents the earliest starting time of a wet appliance and t_{end} represents the latest time at which the wet appliance must have finished its task). An additional constraint can be considered in the specific scenario where only the starting time of the load is flexible (i.e. the only decision variable is the starting time of the load) and the load profile, denoted $u_{load}^{profile}$, is completely fixed (Figure 16A and B , e.g. a dishwasher power profile):

$$\boldsymbol{u_{load}}(t) = u_{load}^{profile}(t - \boldsymbol{t_{start}}) \tag{51}$$

where $\boldsymbol{t_{start}}$ is the decision variable representing the start time of the flexible load and $u_{load}^{profile}(t)$ is the power profile of the load between starting and ending times. In the case of a fixed power profile, equation (50) can actually be expressed as a constraint on $\boldsymbol{t_{start}}$:

$$t_{init} \leq \boldsymbol{t_{start}} \leq t_{end} - \Delta T_{load,profile} \tag{52}$$

where $\Delta T_{load,profile}$ is the time duration of the fixed power profile (e.g. 1h30 for a dishwasher).

Figure 16 shows two examples of load shifting: Figure 16A represents the possible shifting of a fixed power profile load, while Figure 16B represents a more general example where the load profile can also change, but an energy constraint is applied such that an increase of power consumption at one moment leads to a decrease in power consumption later inside the time interval between t_{init} and t_{end}. As an example, it could be a machine in an industrial process that decreases its output production but then needs to produce more afterwards, to compensate the loss of production due to the reduced energy consumption)

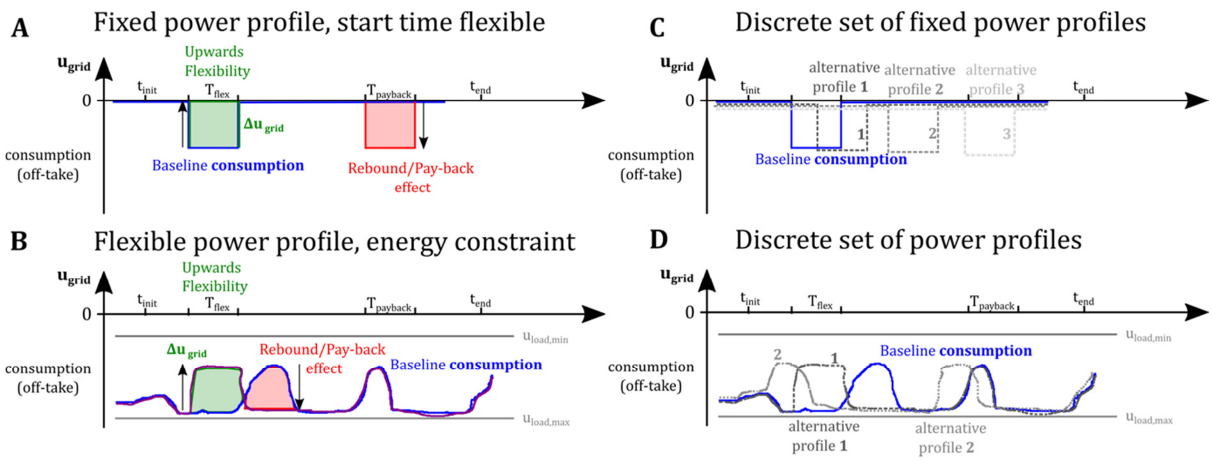

Figure 16: Example of load shifting using explicit constraints (A, B) or a discrete set of power profiles (C, D) for fixed power profiles loads (A and C) and flexible energy-constrained power profiles loads (B and D)

Alternatively, another strategy can be used. No mathematical modelling is actually done, but instead, the shiftable load provides a discrete finite set of alternative power profiles (see Figure 16C and D) to the aggregator, such that he can leverage the flexibility by choosing one profile vs another. Depending on the complexity of the model and based on data availability, the most suitable approach is chosen. Furthermore, methods to tackle both kind of models are described in [3] to then transform this flexibility into bids on the AS markets.

In terms of flexibility cost, the following components can be considered for shiftable loads:

- a discomfort cost may apply in the case of user related loads (e.g. wet appliances) but also industrial processes (but not quantifiable, [65]). There is no discomfort cost if equation (52) is satisfied, but as an alternative, the user might remove this constraint and instead penalize the time shifting of the load compared to the baseline power profile of the load.

$$discomfort\ cost\ = \lambda_{discomfort}^{shifting} \cdot \left| \boldsymbol{t_{start}} - t_{start}^{baseline} \right| \tag{53}$$

- changes in operational costs can include different items depending on the type of loads. For wet appliances, the changes are simply the changes in electricity cost (in case electricity tariffs are not constant), while for industrial loads, it can include several components [65], including electricity cost, but also manpower cost (additional with respect to the baseline), maintenance costs, reduced efficiency losses and fuel costs (in case of on-site generation, behind the meter).
- in load shifting of industrial processes, we assume that the production level is maintained and so we assume no, or very little changes in revenues.
- indirect cost includes storage costs ([48] , production advanced) and delayed production cost (production delayed) and also potentially electricity costs linked to payback/rebound effects and potentially varying electricity prices, in case of industrial load shifting. For wet appliances, it only includes changes in electricity cost.

In general, load shifting costs are agreed to be potentially quite low, even for industrial processes [48]. For the latter, they would anyway be much smaller than the load curtailment costs for which there would be a loss of revenues due to a modified production (see section 2.4.8). In Annex A, Table 31 (for wet appliances) and Table 32 (for industrial shiftable loads) represent ranges of values (when available) and/or comments and methodologies used to obtain values for the model parameters described previously.

2.4.8 Curtailable loads

As mentioned in previous section, load curtailment[14] refers to a reduction of load (which can also be caused by an increase in on-site power generation, behind-the-meter, if there is still a net load consumption), without any impact on the load profile after the curtailment event (this is what differentiates it from load shifting). It can be illustrated in Figure 6A (if load is considered instead of generation) no rebound/payback effect is observed.

Lightning is a typical example of a load that can be curtailed without any payback effect. It includes household lightning (to a small extent), commercial building or industries lightning (to a larger extent) and even public outdoor lighting. Other examples of curtailable loads include industrial processes: although most of them are shiftable in nature (see section 2.4.7), these processes can also be considered as curtailable [59] when the production level must not to be strictly maintained. As a consequence, it is expected that the flexibility cost to curtail an industrial process machine is much higher than shifting it in time, since a production level decrease results in a loss of revenues.

In terms of modelling, minimum and maximum load power constraints apply (see equation (3)) as well as ramping constraints (even if it depends very much on the process). Concerning reactive power, similar settings can be considered as for load shifting, i.e. a fixed power factor is assumed.

In terms of flexibility cost, the following components are considered

- a discomfort cost may apply, typically for household appliances (like lightning). A simple model consists in assuming that the discomfort cost is proportional to the difference between the baseline power profile, $u_{load}^{baseline}$, and the current load profile (once curtailed), $\boldsymbol{u_{load}}$:

$$discomfort\ cost\ = \lambda_{discomfort}^{load\ curtailment} \cdot \left|\boldsymbol{u_{load}} - u_{load}^{baseline}\right| \tag{54}$$

- changes in operational costs are similar to the ones described in the section 2.4.7 and of course depend on the type of load (household, industrial process).
- For industrial processes, as opposed to load shifting, the production level is assumed to be affected largely by the curtailment event, and thus it is assumed that there is an important change of revenues when providing the curtailment flexibility service. For the remaining loads, no (changes of) revenues are considered.

As an alternative to the detailed flexibility cost components, for which it can be difficult to collect data, flexibility cost could be obtained by considering the total interruption costs [66] for different consumer segments (e.g. households, vacation houses, industries, services, ..). Such information can be used to

[14] "curtailment" word was chosen instead of "shedding" to avoid any confusion. Indeed, load shedding also refers to system operators switching off entire portions (i.e. feeders) of distribution grids (as a last option to avoid non-planned black-out). Also, load shedding sometimes also refers to load interruption, in which the load is totally switched off. In our case, load curtailment simply is not as restrictive and it can be a simple slight decrease in the baseline load consumption.

estimate the curtailment cost, by assuming that the cost of full curtailment (i.e. no consumption at all) is equal to the cost of (un)planned interruption as described in [66] (in practice, this might not be true since the curtailment is limited to u_{load}^{min} , at a likely lower cost than a full interruption). The flexibility cost used to provide partial curtailment can be retrieved afterwards by using a proportional rule (e.g. for a curtailment of 10% of $\boldsymbol{u_{load}}$, flexibility cost is 10% of the interruption cost). Additionally, the duration of the load curtailment impacts also the unit cost [66].

2.5 Models for advanced power technologies

In addition to the various sources of flexibility resources described previously, network operators have at their disposal other assets to enhance the flexibility in their grid. Such assets include conventional devices (e.g. OLTC transformers in primary substations or capacitor banks…) but also more innovative and advanced devices based on power electronics.

Indeed, FACTS (Flexible Alternating Current Transmission Systems) devices are usually used in transmission networks for voltage regulation or for the provision of specific services (e.g. power flow control, increase of the transmission power limits, damping of oscillations, etc.…). Due do their relatively high complexity and cost, FACTS are mostly used in the transmission system (this is motivated by the high power involved, the high cost of network reinforcement as well as the complexity of the meshed transmission grid). In particular, the high penetration of DG increased the need of this type of devices to manage voltage in the transmission network (Figure 17), mostly because of the higher reverse power flows in primary substations and the decrease of available generators in the transmission network.

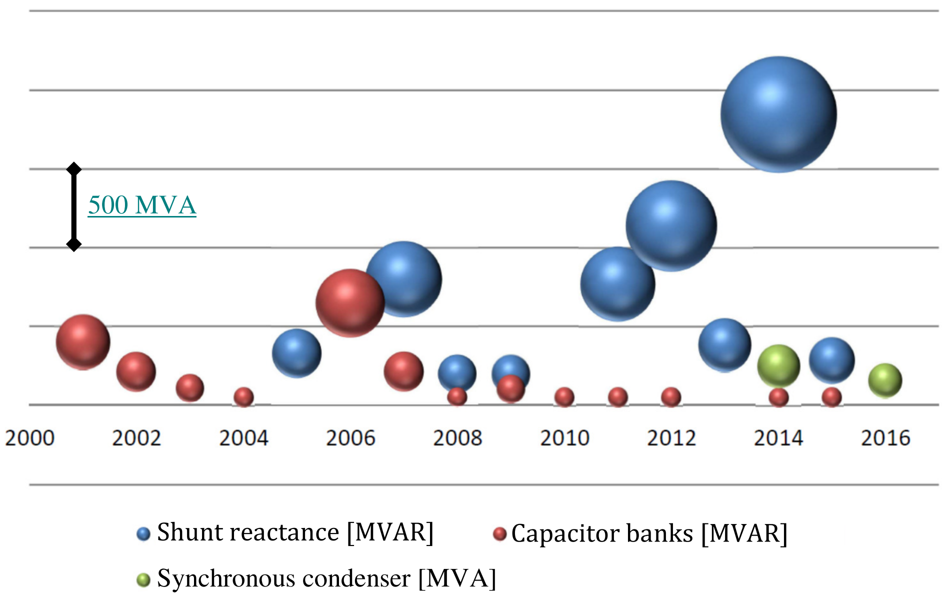

Figure 17: Installation of reactive power management devices in the Italian network [67]

Many FACTS devices are designed specifically for transmission networks and do not find applications in distribution networks (Table 5). For instance, some of them are used to manage the power flows in meshed grids (e.g. phase shifter, phase angle regulator (PAR)…) or to support the stability of the power system (e.g. unified power flow controller (UPFC)). Such functionalities are not relevant in distribution networks, due to their radial nature and the lack of stability issues.

Table 5: list of devices that are used in transmission network, but are not relevant in distribution network.

Devices
SMES (Superconducting Magnetic Energy Storage)
SSSC (Static Synchronous Series Compensator)
TCSC (Thyristor Controlled Series Compensator)
UPFC (Unified Power Flow Controller)
IPFC (Interline Power Flow Controller)
PAR (Phase Angle Regulator)
TCPST (Thyristor Controlled Phase Shifting Transformer)

Smaller versions of these devices, called D-FACTS, can be used in distribution networks as well, but until now, their passive and radial nature made the use of the devices unnecessary. However, the massive integration of RES at the distribution level combined with the observed costs reduction in power electronics (and so of the FACTS devices) make the use of these resources (economically and technically) possible in the future. In addition to the D-FACTS, other devices can be used to increase the flexibility of distribution networks, such as distribution power electronic transformers, MV/LV On-Load-Tap-Changer.

In order to identify and analyse the most promising solution which can provide additional flexibility, a survey has been realized within the partners of SmartNet (RSE, Ustrath, Edyna and SELTA). The results reported in Appendix B (Table 34 and Table 35) show that for many devices the opinion differ very much regarding their future diffusion. From the complete list of devices, we selected and analysed the resources that find application in distribution networks only in order to compare them with the DER for flexibility provision. Table 6 below presents the main families of solutions.

Table 6: list of the devices that can be used in distribution network and their classification.

Group	Devices
Distribution transformers	Distribution Power Electronic Transformer
	OLTC (On-Load-Tap-Changer) MV/LV
Reactive power compensators	SVC (Static VAR compensator)
	D-STATCOM (Distribution Static Synchronous Compensator)
	Synchronous Condenser (SC)
MVDC Networks/Links	Medium Voltage (multi-terminal) DC network
Interphase Power Controllers	IPC (Interphase Power Controller)
Measurements devices	Real time spectrum analyser
	Current and voltage measurement
Failures and emergency devices	STS (Static Transfer Switch)
	DVR (Dynamic Voltage Restorer)

Among the D-FACTS and the advanced technologies presented above, the following can support the management of the network (both in normal operation and in emergency conditions) in order to help the RES integration, and are able to modulate the exchange of reactive power with the transmission network, allowing a better management of the HV voltage and increasing the efficiency:

- **MV/LV Distribution transformers:** improve the control of the MV/LV networks, modulating voltages;
- **Reactive power compensator:** modulate the voltage and the reactive power flow;
- **MVDC (Medium Voltage Direct Current) Networks/Links:** allow a better connection of the DG and improve the MV networks management;
- **Interphase Power Controllers (IPC):** they are similar to MVDC Links, but simpler. They allow a controlled exchange of power between MV networks or between the phases of a lines in order to reduce unbalances.

Although the four aforementioned families are able to overcome failures and contingencies with the right control scheme, some devices are specifically designed to support the network during instabilities or failures:

- **Static Transfer Switch (STS):** allow increasing the availability and reliability of the resources;
- **Dynamic Voltage Restorer (DVR)**: are used to sustain, or restore electric load during short voltage dip.

Furthermore, DSOs pointed out in the survey that these devices have to be coupled with measurements devices to provide the correct regulation. Therefore, these have been highlighted in this deliverable in order to underline their importance, even if they have not a direct effect on the network state.

In the following sections, the characteristics of each family presented in Table 6 and the impact on the DSO/TSO interaction are examined. Since these advanced power technologies are owned and operated by network operators, their model is not focused on the bid creation (in contrast with the DER families for which flexibility models have been developed in section 2.4), but rather on their physical integration in the networks. Some models can be easily integrated in the distribution networks operation, in particular the distribution transformers and the reactive power compensators.

2.5.1 Reactive power compensators

The first family of devices is able to exchange reactive power with the network. There are different class of devices: they go from the simple capacitor bank[15] to the more complex D-STATCOM (Distribution Static Synchronous Compensator). With increasing complexity also the number and types of functionalities increase. For instance, while widespread capacitor banks can only correct the power factor and the voltage with a step size regulation, D-STATCOM perform a continuous regulation, so they improve the power quality as well. Different levels of complexity can be used to model these devices [68]–[72], however, for simulations purpose, reactive power exchanges will be modelled only.

The devices which can modulate the reactive power are the following [73]–[77]:

- **Static VAR Compensator (SVC):** It consists of a Thyristor Controlled Reactor and a Fixed Capacitor (TCR+FC). The SVC can rapidly fix the bus voltage at a desired value or compensate the power factor [78]–[81]. Therefore they can be used to compensate rapid voltage drop, but they perform poorly in power quality improvement (waveform shape, phase unbalances…). The SVCs are the simplest devices after capacitor banks; the plain design allows easy installation and operation.
- **D-STATCOM:** This power electronic device can solve power quality issues such as voltage fluctuation, flickers, current distortion, voltage unbalances [82]–[86]. It is more complex, but in counterpart it shows better performance in terms of flexibility and response time, therefore it allows to provide more ancillary services. Besides, the D-STATCOMs are becoming an industrialized solution with high reliability and robustness.
- **Synchronous Condenser (SC):** This rotating synchronous machine which can control the voltage and the reactive power improves the power quality. It is able to give support for primary frequency regulation. The Synchronous Condenser has a performance comparable to the D-STATCOM. Its main advantages are the provision of high quality

[15] Although capacitor banks are not considered as advanced power technologies, they are found in most of the distribution networks for reactive power regulation.

waveforms and their ability to support the primary frequency regulation. Its principal drawback is its minimum size (in the order of 10 MVA), which makes it hard to find applications in the distribution network. Nevertheless it could represent a good solution for wind farms connections due to their large size.

2.5.1.1 Model

In some cases the reactive power is step-size regulated (e.g. capacitor banks), but the steps are too complex to be implemented in the control model due to their discrete behaviour. For the sake of simplicity, these devices are modelled with a continuous capability. If the number of steps is high, the error introduced can be neglected but for some devices this approximation cannot be taken (it is for example the case of large capacitor banks connected near the primary substation, which can only be connected or disconnected). In this specific case the state of the device is determined during the planning phase of the network and not in real time; then the connection state is an input of the optimization procedure, not the output.

Considering these simplifications, all these resources can be modelled as continuous reactive power exchanger with capability:

$$\mathrm{q}_{gen.i}^{min} \leq \boldsymbol{g}_{\boldsymbol{gen.i}} \leq \mathrm{q}_{gen.i}^{max} \tag{55}$$

Where $\boldsymbol{g}_{\boldsymbol{gen,i}}$ is the reactive power exchange, $q_{gen,i}^{min}$ and $q_{gen,i}^{max}$ are respectively the minimum and maximum reactive power provided by the device (they depend on the size and type of resource). The active power is not taken into account in the model since it can be considered as constant or negligible.

2.5.1.2 Effects on the TSO-DSO interaction

The aforementioned devices could have a great influence on the interaction between TSO and DSO. The voltage regulation enables the use of more resources in the distribution network increasing the possible RES generation. The reactive power modulation decouples the exchange of reactive power between DSO and TSO.

In the first case they allow the DSOs to control the voltage without other resources (local generators…) or with their limited contribution. In this way the interaction between DSO and the other participant of the power system (TSO, aggregator, final user…) can be very limited.

In the second case, they allow decoupling the exchange of reactive power between the distribution and transmission network if located near the primary substation. This can be very important in the future, since in the regulation of different countries, the limitation on the power factor values have been introduced. Besides, the penetration of the distributed generation and the possible local control of the resources heavily influence the power factor of the primary substation increasing the issues for the DSO to control the flows of reactive power. This affects directly also the management and the efficiency of the transmission network. In order to overcome this problem, DSOs have already installed reactive power compensators in their primary substations. However, these are usually very simple devices, such as capacitor banks, which have limited regulation capacity. The introduction of more advanced devices can help the DSO to modulate the power factor and also to participate to the modulation of the voltage in the transmission network. Besides, an important percentage of the distribution network losses are located in the HV/MV transformers: reducing the reactive power flows going through these transformers can increase the global network efficiency.

Finally, the D-FACTs can generally increase the controllability and reliability of distribution networks allowing a better integration of the distributed resource.

2.5.2 MV/LV Distribution transformers

The transformers are fundamental devices used to control the voltage. In particular two type of transformers are investigated hereafter:

- **DPET (Distribution Power Electronic Transformer)** are power electronic transformers that enable controlling the voltage almost continuously, decoupling the reactive power exchange at both sides of the transformer. They are ideal to control the voltage and the reactive power flow. They can be installed at the interface with LV networks or along a feeder, with a complex behaviour [87]. The drawback of this solution is its high cost and for this reason they are mostly used to protect sensitive loads.
- **MV/LV transformers with OLTC (On-Load-Tap-Changer)** are MV/LV transformers equipped with an OLTC [88]. In this way it is possible to partially decouple the voltage of the LV network with respect the MV network voltage, resulting in an increase of the voltage limits in the MV network.

Within the distributed transformer, UPFC (Unified Power Flow Controller) could be included as well, combining the functions of voltage and current compensation. They can compensate both the load harmonics and the reactive current in order to eliminate the impact of load to the grid and also can control the voltage quality of the end user to reduce the impact caused by grid voltage problems on users [75], [76].

2.5.2.1 Model

From the modelling point of view, the DPET corresponds to a series OLTC with a D-STATCOM at the primary winding. Instead, it is not necessary to model directly the controllable MV/LV transformers, since their effect on the MV network is, in first approximation, to increase the available voltage band up to ±10%. In fact, the total available voltage band is ± 10 %, but, in order to take into account voltage variations in the LV network, a voltage band of ± 5 % is usually considered for the MV and LV levels. Decoupling these levels with an OLTC distribution transformer results in an increase of the MV level voltage band up to ± 10 %[16].

2.5.2.2 Effects on the TSO-DSO interaction

The distributed transformers allow a better management of the distribution network and reduces the necessity of using DERs to solve local voltage violations. It enhances the participation of DER in flexibility provision by releasing an additional voltage band.

2.5.3 Medium Voltage (Multi-terminal) DC Networks

Today, due to the significant progress in the fields of power semiconductor devices and cable technology, new technologies are entering into the power distribution and transmission system (Figure 18). In general, medium voltage DC (MVDC) networks are less expensive and have lower losses compared to AC (Alternating Current) systems. They provide better means to enlarge the share of DER and at higher efficiency compared to their AC counterparts. Also, MVDC systems are particularly suitable for the application of small-scale industrial networks with high share of devices that decrease the power quality of the voltage (nonlinear load…), due to the more flexible interfaces that is guaranteed by the power electronic converters. In addition, they allow power exchange between unsynchronized AC systems

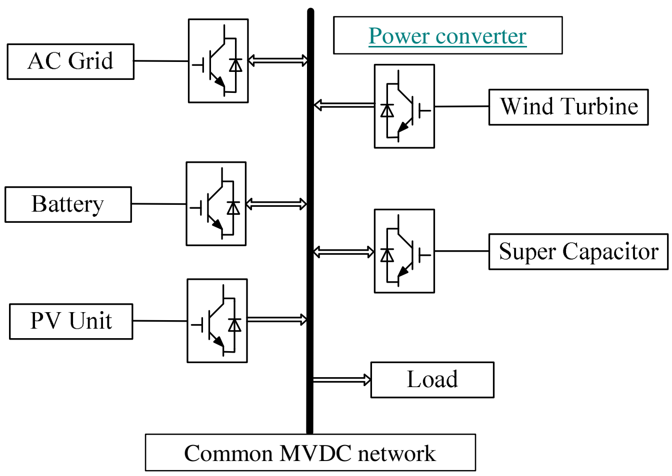

Figure 18: Example of a MVDC Network, where all the distributed resources are connected to a same DC network. The DC network is then connected to the AC main power system by a single DC/AC converter, which guarantee high performance in power quality[89].

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[16] The exact values depends on the specific DSO and regulation.

Compared to High-Voltage DC (HVDC) transmission system, multi-terminal MVDC systems have significantly lower power levels, as well as reduced DC voltage levels. Thus, for the electronic power converters, fewer semiconductor devices are connected in-series to support the DC voltage. This simplifies significantly the station converter design, considering the voltage sharing among the series-connected semiconductors.

In order to cope with the challenges brought by higher renewable energy penetration to distribution power system, multi-terminal DC networks can be incorporated into the distribution power system [89]. They can enhance voltage profile and load availability, and facilitate more flexible and faster power flow control over emerging renewable energy without significant contribution to fault current. For now there are few applications, but in future the MVDC grids can find broader applications [90].

- Power Flow Optimization: The MVDC networks have the capability to reduce the loss for the distribution system.
- Higher Reliability: Though radial topology is most commonly used in distribution network for its simplicity feature, electric ring topology are also widely implemented. With MVDC links incorporated into the ring network, the system fault impedances maintain current levels [91].
- Reactive Power Generation Capability. In addition to the aforementioned active control, the VSC in the MVDC networks can simultaneously generate or absorb reactive power to contribute to the AC-side voltage control.

2.5.3.1 Model

From a network model point of view, the MVDC network can be seen as an aggregation of resources exchanging power, at the same time, with different busses of the MVAC networks. Thanks to the power electronic interfaces the exchange of power of each connection point can be controlled independently, respecting the total energy balance. In this way the power is injected only in the node of the AC network which can accept it without violating the constraints. Besides, the MVDC network can also solve congestions in some areas of the network, redirecting the active power in more suitable areas. In particular, the reactive power exchange at each connection node between the MVDC networks and the AC network is controllable. Thus, the reactive power can be used to support the MVAC network, even in the case of one single connection node. Usually, since the connection is provided by power electronics, the capability is circular, but rectangular or triangular capabilities can be considered. Finally, the MVDC networks allow also to transfer power between the different feeders of the MVAC networks where they are linked.

2.5.3.2 Effects on the TSO-DSO interaction

The MVDC Networks/Links can have three main effects on the TSO/DSO interactions. They allow higher integration of RES devices, increasing indirectly the amount of power that the DSO can deliver to the TSO. Besides, since the exchange of reactive power between DC and AC is controlled, they allow to control the reactive power flow between the MV and HV network levels. Finally, if the MVDC link connects the feeders of two different primary substation, they can ideally affect also the active power flow of the transmission lines connecting the two substations, reducing for example power congestion of the transmission system.

2.5.4 Interphase Power Controller

IPCs can interconnect two sub-networks with DERs, as shown in Figure 19. Based on the series connection of impedances between different phases of the two interconnected sub-networks, an IPC can not only control the power flow between the sub-networks but also effectively limit the fault current. In particular it can be used to regulate the power flow. It is suitable for the following applications:

- Active Power Flow Regulation: IPC can be used to manage the active power flow exchange between e two connected networks with DERs. It increases the power transfer capability of the existing power distribution facilities by redirecting dynamically the power in the network with the higher capacity [92].
- Reactive Power Management: IPC can also absorb or generate reactive power with the interconnected systems. The reactive power injected into or taken from the system is therefore the same at both terminals of the IPC.

2.5.4.1 Model

An IPC is a series-connected controller of active and reactive power and has inductive and capacitive branches in each phase. Each terminal of the IPC behaves as a voltage dependent current source and provides the IPC with the unique decoupling effect property, while controlling power flow under normal and post-contingency conditions [93], [94].

The model of the IPC for the steady state operation is quite similar to the MVDC Links (and more in general to the DC Links). The active power of the two connection nodes has the same absolute value (neglecting the losses), but opposite signs. The reactive power modulation at the two nodes depends on the characteristics of the converter and, within the capability limits, it is independent from the active power. As shown in Figure 19, the controllable parameters of IPC are the phase shift angles (αA and αB) and/or the branch impedances (L and C). The phase shifting devices can be conventional or electronically switched phase shifting transformers. An IPC with electronically switched phase shifting devices adds dynamic regulation capabilities to the power system. As a consequence, not only the steady state stability properties but also the transient stability performance of the power system is improved limiting the fault current effects on the TSO-DSO interaction

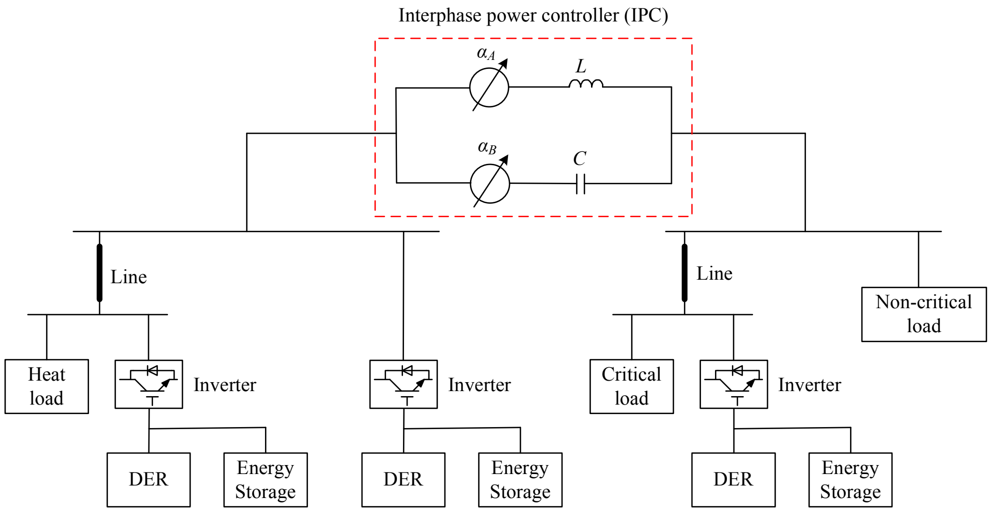


Figure 19: Two different lines connected by IPC [95], which can control the exchange of power between the two systems.

The effects on the TSO-DSO interaction are similar to those of the MVDC-Links. The exchange of reactive power allows to modulate the exchange of reactive power with the HV network and to improve the power quality.

2.5.5 Measurement devices

The measurement devices cannot directly influence the power flow of the network, but the increasing necessity of an accurate estimation of the network states places these devices on top of the list of necessary tools. There are mainly two types of devices:

- **Real time spectrum analysers** are used to measure the power quality. The introduction of distributed generation, the control tools like the D-FACTs, and the power electronic loads can introduce disturbance in the distribution network. This disturbances decrease the power quality affecting the final use of the electric power and the PLC communication (Power Line Communication). Those effects can be reduced for example by the use of active filter in strategic places. The real time spectrum analysers are important to monitor the power quality, find the devices which create disturbances and locate the best position of filters
- **Current, voltage and powers meters are** necessary to obtain a correct evaluation of the network state, which is of primarily importance for the implementation of control strategies. In particular with the increase penetration of generation and new type of

loads (Heat Pump, EV…), it is becoming more and more difficult to estimate the correct state of the network with only the historical data and the measurements in primary substation. Thus, the measurement devices combined with forecasting tools are becoming necessary for a secure and efficient network operation. The type, number and position of the devices depend on the adopted control strategies. In general centralized control strategies require more devices since it is necessary to estimate the whole network state.

2.5.6 Static Transfer Switch

A Static Transfer Switch (STS) is conventionally equipped at the PCC (Point of Common Coupling) to isolate the distributed energy resources from the grid in case of grid faults and reconnect seamlessly to the grid when the faults are cleared. Due to the use of power semiconductors rather than mechanical moving parts, the opening/closing action of STS can be completed rapidly (within a quarter-cycle of the power frequency [96]).

The STS is preferably controlled independently with a central control or power management unit, which constantly monitors the utility voltage condition and opens the switch in the case of a utility fault. The controller of each DER system uses local voltage and current measurements in order to control the output voltage and power flow. However, there is still a need for low-speed communication between the STS and the DER units to update them about the status of the switch, i.e., whether it is opened or closed [95]. STS can be used for various applications:

- Fault isolation to protect the DERs: In normal operation, the DERs are connected to the utility and they provide heat and power support for the nearby loads. When a fault occurs in the system, the STS at the PCC opens, disconnecting the DERs from the utility as fast as possible to supply the loads in islanding mode [97]–[99].
- Uninterrupted power supply to the local loads. Although a fault is applied at the utility grid, local loads are connected on the DER side of the STS so that they are always supplied with electrical power regardless of the status of the STS. By using the STS for the DERs, the power supply interruption time with even a few power frequency cycles can be avoided [98]–[100].
- Reconnecting DERS to grid after grid fault clearance. After the grid fault is cleared, the STS reconnects the DERs to the utility grid and ensure transient-free operation, by monitoring the voltage signals on both sides [95], [101].

2.5.7 Dynamic voltage restorer

DVR represents the devices (e.g. voltage source converters, storage units…) that are used individually or in coordination, to sustain or restore an operational electric load during voltage events such as sags or spikes. This device deserves a brief mention due to the increase necessity of high power quality for specific applications (e.g. server…) [78], [79], [88], [102]. Besides, they improve the stability of the network allowing to maintain the loads connected, increasing the network reliability.

3 Provision of ancillary services with flexible resources

In Chapter 2, a taxonomy of the DER and mathematical models specifying their simplified dynamics (the targeted time scale is minutes to hours) and their physical constraints (for the provision of flexibility) were described. Cost components required by the provision of flexibility by the DER were also specified. The objective of the present chapter is to outline the potential role of DER for the provision of current and future AS. Therefore the technical capabilities and the availability of flexible resources in providing current and future ancillary services are discussed.

The analysis is carried out in the following order: in section 3.1, the methodology is explained, then in section 3.2 a qualitative mapping between flexibility resources and current and future ancillary services is presented, focusing mainly on the technical capabilities of the flexible resources. In addition, the capabilities of advanced grid technologies (section 2.5) in increasing flexibility at the interface between the TSO and DSO networks is investigated as well. Finally in section 3.3, the availability of flexibility resources in the pilot countries is quantified, based on 2030 scenarios defined in SmartNet deliverable D1.1 [1], and then compared to the need of each type of AS.

3.1 Context and methodology

3.1.1 Main principle

For a flexibility resource to participate in the provision of current and future ancillary services, there are very specific criteria which have to be met. Among these requirements are: the minimum bid size, the duration, the full activation time, the possibility for resting time, etc. Hence, there are differences among flexibility resources in their ability to respond to an external signal with minimal disruption to their respective essential services, due to their specific dynamics and technical constraints. Even within similar types of DERs, there might be capability differences due to the type of grid-coupling technologies. These differences have to be accounted for in the effort to quantify the potential availability of DERs for AS provisioning in each of the pilot countries and for current and future scenarios defined in [1]. This shall encompass the total volume of each resource (e.g. the installed capacity of PV or the total energy consumed by TCLs) as well as the actual share of resource able to participate in each category.

Thus, in order to calculate the amount of flexibility potentially available, we need to establish a method translating the total installed capacity into a specific amount available to the ancillary service need. The main principles of the methodology are as follows:

- The quantification is dependent on the technical capability. The potential for some flexibility resources is strictly dependent on the market design and how it reacts to uncertainties with DERs. Hence, the quantification of flexibility resources shall be interpreted with a specified market conditions if one needs to use the collected data further as no market limitations are considered in the quantitative mapping process. As an example, the amount of available flexible power for providing up or down regulation is limited by the previous commitments on the energy markets (intraday, day-ahead) and it is very unlikely that a resource will be only dedicated to the AS provision (except perhaps for storage devices). However, this is not considered in this quantitative mapping process, since it is not possible to describe all different market situations for all types of devices.

- The calculated values shall be envisioned so that they are available in terms of GWh/year or MW without making direct link with the ancillary service need. This is because the actual linkage depends on the market scenario and the time of the day or the year (for instance, PVs are only available on day time and other seasonal loads are available seasonally)
- For later utilization of the results, the GWh/year can be converted to MW for specific scenarios and times of the year later as required by using the values in the table.
- The mapping is established for both distribution level and transmission level connected flexibility resources.

The following equation is used for this purpose:

$$\mathbf{AvailableFlex}(\mathrm{MW}) = \mathbf{FlexRes}(\mathrm{MW}) * \mathbf{MAP}(\%) * \mathbf{FLEX}(\%) \qquad (56)$$

Where $\boldsymbol{FlexRes}$ is the total capacity of the resource (e.g. the installed wind turbine capacity), $\boldsymbol{MAP}$ represents the technical capability of the individual flexibility resources in providing the concerned AS and $\boldsymbol{FLEX}$ is the share of resources able to provide flexibility among the total capacity (for curtailable loads, this parameter can be represented by the percentage of loads actually able to provide flexibility).

Hence the value of $\boldsymbol{MAP}$ is obtained through the qualitative mapping of the flexibility, for which weights ranging from 0 to 4 are defined. These weights, which are linked to the performance of a resource to provide a specific AS, are translated into the MAP parameter with the corresponding Table 7.

Table 7: Mapping weight to factor translation (MAP%)

Capability to support the ancillary services needs	Weight (coding of qualitative mapping for DER to provide AS)	MAP (%)
indicates very good capabilities	4	100
indicates good capabilities	3	75
indicates little capabilities	2	50
indicates very little capabilities	1	25
indicates no capabilities	0	0

The $\boldsymbol{FLEX}$ can be dependent on the specific scenario considered in the specific pilot country and also on specific reasons. Although the $\boldsymbol{FLEX}$ value can theoretically be different for upward and downward reserve needs, we assume it as equal in this report.

3.1.2 Followed methodology

The global process followed to evaluate the AS provision by flexibility resources in current and future times is illustrated in Figure 20. In mapping for future ancillary services, it is assumed that with the right retrofitting all flexibility resources can be made capable of provisioning the services. The justification for the qualitative mapping weights provided for each of the flexibility resources is discussed later in section 3.2. Nevertheless, the general guideline for the qualitative mapping weight values includes their physical capabilities, their size and availability as well as the cost of retrofitting they require (additional effort required to make the flexibility resources capable in the future).

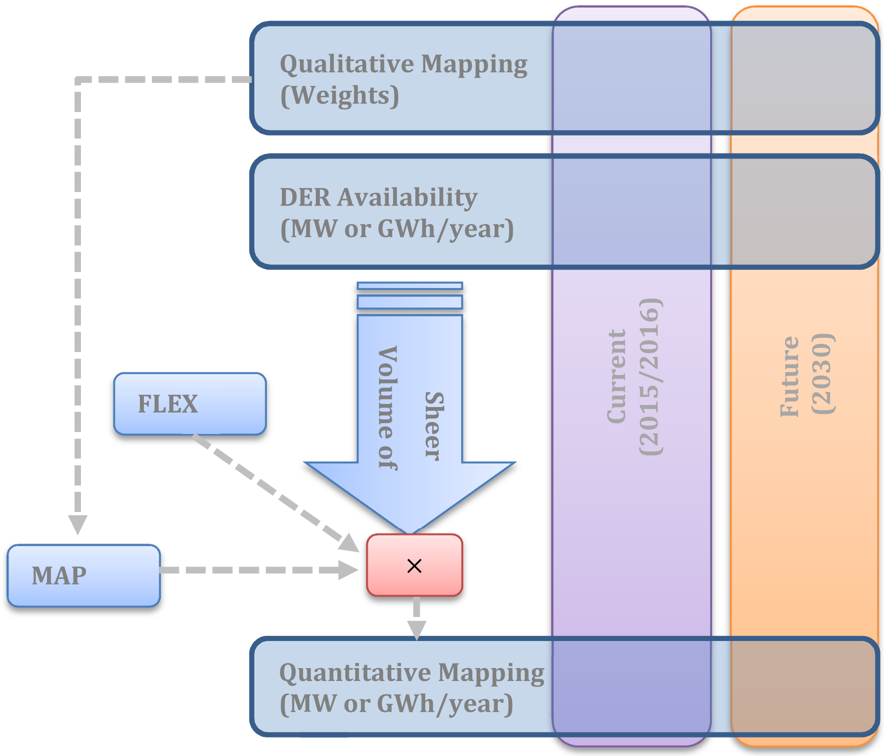


Figure 20: Procedures followed in the qualitative and quantitative mapping of flexibility resources

First, the qualitative weights for each DER with respect to individual current and future ancillary services are defined (they range from 0 to 4, as illustrated in Table 7). Although the aforementioned general reasoning is followed in qualitatively mapping of flexibility resources, a more specific justification is provided explaining the weights corresponding to the specific services and flexibility resources. This is required to impede the unavoidable subjective evaluation in the weights and more importantly to give perspective in order to have meaningful interpretation of the qualitative mapping results. Secondly, the availability of each DER in current and future scenarios is evaluated for each pilot country and the format of the inputs data is discussed. Finally we define the FLEX parameter and we apply the formula (equation (56)) defined previously in order to quantify the provision of AS.

3.2 Technical capability evaluation of flexible resources and advanced power technologies

In this section, the capabilities of DER and advanced power technologies for provisioning of ancillary services are evaluated. The capabilities can be assessed based on their technical capability and availability. As presented in Chapter 3, DER can be grouped into three main categories: Energy Storage, Distributed Generation and Flexible Loads. In section 3.2.1, the influence of grid-coupling technologies on the technical capabilities of distributed generation is discussed first. In section 3.2.2, the qualitative mapping results and their justifications are presented for each family of DER. Finally, the capabilities of advanced power technologies are presented in Section 3.2.3.

3.2.1 Influence of the grid-coupling technology

All DG units have a grid-coupling device, which feeds electrical energy into the grid as the last element of a chain of energy converters of the unit [103] (see Figure 21), and the capability of the same flexibility resource varies significantly depending on the technology used. For example, wind turbines connected to the grid with inverters have higher reactive power control capabilities than those connected with Doubly-Fed Induction Generators [103]. There are four typical grid-coupling technologies currently in use: squirrel cage induction generator (IG) which is the simplest grid coupling technology; synchronous generator (SG) directly coupled to the grid; doubly-fed induction generator (DFIG) which consist in a power converter connected to the rotor through slip rings controls the rotor current; and finally inverters (Inv). The capability variations of the different coupling technologies under individual DER are qualitatively mapped in Appendix C (

Table 36 and Table 37).

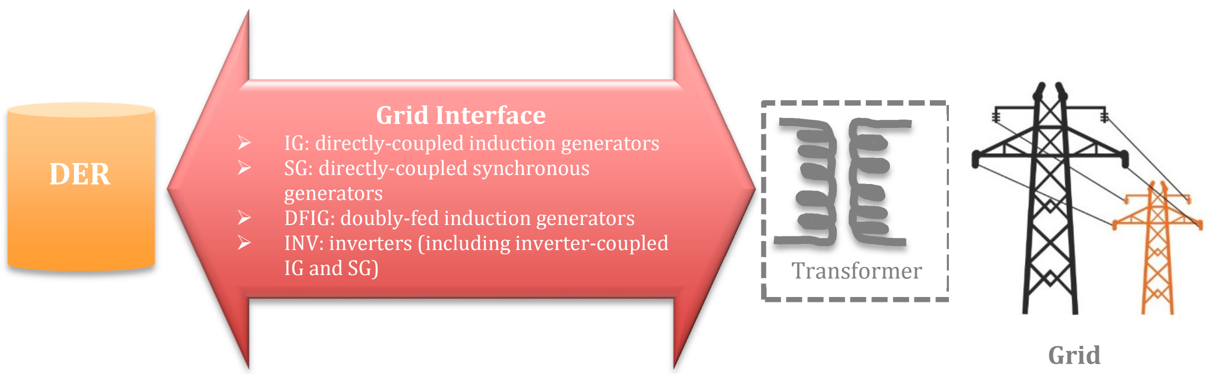


Figure 21: Grid Interface types for DER

The technical capabilities of different grid coupling technologies for providing different ancillary services depends on some basic control capabilities. For instance, inverters present excellent controllable characteristics and currently all modern inverters are capable of providing active power control (they are able to ramp up to full power within 500 ms to 1 s depending on the design [104]).

For those flexibility resources having variety of interface technology options, we considered the mapping weights by taking the average value. However, if the necessary data is available the individual interface type weights can be multiplied with the proportions of the individual technology, which later be summed to give the total weight for the flexibility resource.

3.2.2 Qualitative mapping for distributed energy resources

In this section, the flexibility resources described in Chapter 2 are qualitatively mapped towards current and future ancillary service needs in terms of their technical capability to provide these services. For each DER family, detailed qualitative mapping weights for current and future times are presented in the Appendix C (Table 36 and Table 37 respectively). The justification for the mapping weights is provided hereinafter for each family:

- **Wind turbines and Solar PVs**

The use of wind power for the provision of ancillary services is already present for the plants of relevant size (superior to 5 MW in Spain). In particular the wind generators coupled by inverter or DFIG have great capabilities for ancillary services exploitation. Regarding the photovoltaic generation there is less experience, but its capability of providing ancillary services is demonstrated both in literature and in European projects. Finally also the national and European regulation are taking into account the participation of the distributed resources to the management of the system.

In general, these renewable sources have not the same flexibility of conventional plants, due to their non-programmable nature and due to the difficulties related to increase the power output. In fact, the control systems of these resources are usually optimized to maximize the power output and not to give other services. Besides, all the power that is not produced is lost. However, for the future, the required need of more flexibility would result in an evolution of the power converter, control solution and aggregation procedures that would allow the participation to the ancillary services also to small units.

- **Pumped-Hydro Energy Storage**

Variable or Fixed speed control is the most important characteristics of Pumped-Hydro Energy Storage (PHES). In the former, the pumping process occurs at a fixed speed (i.e. at the synchronous speed) which does not enable any frequency regulation. Most of the existing plants are operated with fixed-speed SG but recently variable speed units have emerged thanks to the use of DFIG or SG coupled with static frequency converters. PHES are able to ramp-up to full power between 30 s and 1 min and can reverse the mode (pump to generator or vice-versa) in about 30 seconds.

Therefore pumped hydro have overall very good capabilities in terms of frequency and voltage control (DFIG performs better than SG for the reasons above-mentioned). In the future, more and more PHES will be of the variable-speed type, which will improve their capabilities (this is the reason why the qualitative mapping weights are higher for 2030). Some of the AS do not apply to them (e.g. LVRT) due to their size and the fact that they are mostly connected on the transmission grid level; PHES are not suited to provide power quality improvement AS.

- **Stationary Batteries**

Batteries have excellent performance in any domain thanks to their long discharge time, their high ramping rate and the well-known capabilities of inverters for voltage control or frequency control, LVRT, etc. Since the main difference between different technologies is mostly reflected in the costs and the maximum number of cycles but not on their ability to provide AS, only one category of battery has been proposed for the qualitative mapping. Future developments in the batteries field should mostly affect (i.e. decrease) the cost and not so much the technology, that is why the qualitative mapping is very similar between current and future AS.

- **Mobile Storage**

EVs have quite promising performances. In particular, they are well suited for voltage control (they perform relatively well for the primary, secondary and tertiary voltage control thanks to the use of inverters). Also, the frequency control is a potential application for such technology because electric vehicles can provide a quick response for a not tool long duration (this is why scores are higher for the primary control compared to the secondary control). This is well applicable in the frequency and voltage regulations, requiring responses that are faster than a minute with durations of few minutes [105]. Electric vehicles are also able to provide up and down regulation, through the strategy V2G, avoiding dangerous peaks and drops. Finally, the strength of EV is the fact that the investment cost in the battery can be attributed to the primary use of the EV, driving, which makes EV a cheap resource to provide AS. Also, EVs are advantageous because of their scarce use for transportation, estimated to 4% of the time [106]. The remaining 96% of time could be potentially reserved for the AS provision, ensuring availability even during the peak commute hours [106]. However, this later strength could vanish in the future if autonomous cars develop (they would be less available).

- **Combined Heat and Power**

In general, CHPs can be incorporated regardless of time-of-day (contrary to Wind Turbines and PV), but they may however exhibit less flexibility depending on the flexibility of the heat demand and/or the presence or not of a heat storage (to decouple heat production and demand). Their main limit is in ramping delay, hence not being very suitable for fast-reacting AS. For this reason, more capability is indicated for secondary and tertiary frequency control, although usage of CHP even for FCR has been reported in Denmark [107]. Also, SG and fixed-speed IG versions are more capable of frequency regulation because of rotational inertia.

Regarding voltage control, CHPs can provide fixed (IG and SG) or variable (Inv) reactive power, hence suitable for voltage regulatory services (except for limited capabilities of IG version). Most likely voltage regulation capabilities will be improved in future, especially because more advanced inverters can be developed. It is in general predicted that inverter-coupled generators will be more in demand.

The Inv-type CHPs are more capable of providing power quality services, because the power factor is highly adjustable. The capabilities are very similar to a PV [108]. CHPs can be used for Black Start since the initial source of energy is chemical (not dependent on weather or time-of-day) [109]. Similar justifications are used regarding other ancillary services.

- **Thermostatically Controlled Loads**

Due to the thermal mass that is intrinsic to the TCLs (and in particular, to heat-pump based technologies), there is flexibility that can be offered for different purposes. The suitable AS that can be offered by TCL will heavily depend on the thermal mass and the utilization of the TCL. In this line, aggregation can help improve the relevant range of ancillary services that can be provided by TCLs.

The research on provision of ancillary services by TCLs is booming. For instance, in [110], it is stated that air conditioners / heat pump space heaters can provide ancillary services up to the timescale of their thermal time constant of 2 to 6 hours, refrigerators in the timescale of 30-80 hours,, and electric water heaters (boilers) in the timescale of 20-80 hours. Moreover, according to the same source, air conditioners / heat pump space heaters are suitable for second/minute shifting, whereas refrigerators / water heaters can do seconds/minutes/hours shifting. Authors in [111] studied a possible application of a set of refrigerators for provision of frequency containment reserves (primary control). Although there are still many open questions, first results seem to be promising.

The reactive power in TCLs is not a significant element of the model (in this case (57) is applied). In the most simplistic way, TCLs can be seen as a pure resistance used for transforming the electricity to heat (although some of them such as HVAC make use of compressors, they are not equipped of any control allowing a reactive power regulation). Therefore, it is envisioned that TCLs are not suitable for providing ancillary services related to reactive power.

In future, it is expected that the technology will not significantly change, so the scope of the ancillary services that can be offered by TCLs will not conceptually significantly change. Their main possibility for provision of AS will remain as nowadays, in provision of active power in the time range of seconds to hours. In conclusion, the ancillary services related to provision of active power in the time range of seconds to hours are likely to be the most in the capability spectrum of TCLs.

- **Shiftable loads: wet appliances**

Shiftable loads in this category precisely represent non-interruptible (atomic) loads such as washing machines, dishwashers and dryers. For AS such as frequency and voltage support, the control of the flexibility resources has to be fast and automatic. However, fully automated DR seems currently impractical for the aforementioned shiftable loads. In future, with the absence of market barriers and with the increase in appliance automation, flexible domestic appliances can be useful to balance a future electricity system [112]. Alternatively these flexibility resources can be made frequency responsive loads (interruptible) or loads with electric spring (smart loads), which might enable them for some rapid response requiring ancillary services. Hence, the above considerations are taken into account while qualitative mapping of shiftable loads in current (2015/2016) and future (2030) times.

- **Shiftable loads: industrial processes**

The involvement of industrial process loads as rapid frequency responsive loads is in the act of load shedding using under frequency relays. Also, motors inherently provide inertial response to the system. With the increased penetration of DG, the power system inertia is decreasing, demanding larger volume of fast responding reserves. Industrial loads such as bitumen tanks have demonstrated significant potential to provide future inertia needs [113]. In future, frequency support block can be introduced along with standard drive control [114].

- **Curtailable loads**

Loads belonging to this category include interruptible loads that do not have any significant time dynamics such as rebound effects. They typically include lighting loads (for example, modern LED-lightings have excellent, fast and continuous controllability).

Loads are increasingly and predominantly connected via inverters that also have very fast and continuous controllability. The majority of modern curtailable loads are excellent for the provision of very fast reserves and power system inertia. Thus it is not necessary to completely switch off the curtailable loads but only partially reduce the power consumption of a very large number of such loads in order to meet even the whole demand of those power system reserves where these loads are applicable.

The curtailable loads have also significant limitations. For instance some loads may have limited possibilities to increase their consumption (or the benefit is not important enough for the customer) and the shedding of ventilation and pumping loads have limited duration (because of the time dynamics that are hidden when defining the loads as belonging to the category curtailable). Moreover, the size of the loads is often relatively small and as consequence aggregation, activation and response verification arrangements can be rather costly compared to the benefits (especially when the automation and control systems are technically outdated and do not support such functionalities). Finally, there is a significant barrier which is the lack of knowledge from the users and owners of these resources about the shedding possibilities.

The qualitative mappings are summarized in Table 8 and Table 9 illustrating in colour code the capabilities of DERs in supplying the various ancillary services: dark green indicates a score of 4 (very good technical capabilities to provide the AS, while dark red indicates no capability at all to provide the AS.

Table 8: Capabilities of DERs to provide current ancillary services

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									
Voltage	**PVC**									
	SVC									
	TVC									

FCR: Frequency Containment Reserve
aFRR: Frequency Restoration Reserve (automatic)
mFRR: Frequency Restoration Reserve (manual)
PVC: Primary Voltage Control
SVC: Secondary Voltage Control
TVC: Tertiary Voltage Control

Table 9: Capabilities of DERs to provide future ancillary services

Ancillary services		Wind	PV	Stationary Storage: Batteries	Mobile Storage: EVs	CHP	TCL	Shiftable loads: Wet appliances	Shiftable loads: Industrial processes	Curtailable loads
Frequency	FFR									
	FCR									
	FRR									
	RR									
	RM									
Voltage	FRTC									
	CMVC									
	PVC									
	SVC									
	TVC									

FFR: Fast Frequency Reserve
FCR: Frequency Containment Reserve
FRR: Frequency Restoration Reserve
RR: Restoration Reserve
RM: Ramp Margin (Ramp Control)
FRTC: Fault Ride-Through Capability
CMVC: Congestion Management Voltage Control
PVC: Primary Voltage Control
SVC: Secondary Voltage Control
TVC: Tertiary Voltage Control

KEY

	Indicates very good capabilities
	Indicates good capabilities
	Indicates little capabilities
	Indicates very little capabilities
	Indicates no capabilities

Some general conclusion can be highlighted from these figures: the best resources to provide frequency ancillary services are the storage systems as they have high performances and less constraints with respect to other resources; CHPs and industrial shiftable loads also show high performances since both technologies presents similarities with storage systems (CHPs are flexible thanks to the thermal storage system and industrial shiftable loads are very well monitored and controlled because of the industrial processes).

Following these resources is a second group of technologies that has lower performance for long duration AS (a few hours): Wind Turbines, PV, EV and curtailable loads. Their main drawback is the lower predictability which affects their performance over long time horizon. On the contrary, shiftable loads (wet appliances) and TCLs are more suitable for long time horizon AS due to the latency of the response of some devices and the system inertia.

Regarding the voltage services, resources can be grouped into generators and storage on one hand, and loads on the other hand. The first can provide voltage services as they are usually coupled with inverters or synchronous machines, which have good reactive power control capabilities; the main limitation is related to the primary resource availability. Instead the loads have lower capacity to provide reactive power modulation, thus they are usually coupled to external resources such as capacitor banks or STATCOM.

It is necessary to point out that the tables show a general medium behaviour and do not reflect the variability inside each category. It is possible that with the adequate control system, the performances of the systems are increased.

3.2.3 Qualitative mapping for advanced power technologies

Advanced power technologies allow a better management of MV networks and consequently they increase the flexibility at the interface between transmission and distribution networks. Models for some of these devices are presented in Chapter 2. Since one of their function is to sustain other resources, the potential benefits are divided in two categories: in the direct case (Table 10), the devices are able to provide the desired AS, while in the indirect case (Table 11), their ability to sustain other resources in the provision of that service is considered.

Direct support for active power AS is provided only by MV-DC networks and Synchronous Converters. In fact, the use of DC networks allows a better management of the active power production and absorption from local resources. Besides, the use of one single power electronic interface allows a better flexibility and control with respect to multiple small converters.

From the point of view of indirect support, every FACTS can contribute to AS support. Indeed, they can be used for voltage management of MV networks, allowing a better exploitation of other resources providing ancillary services. The performance of this mechanism is strictly dependent on the characteristics of the distribution network so the impact is difficult to evaluate.

However, from the point of view of voltage management all the resources which have power converters can support directly voltage (with different performances depending on the services for which they are designed). MV/LV OLTC and STS (Static Transfer Switch) are only able to provide indirect support as they are not able to exchange reactive power and they can only support the management of resources. In general, the flexibility provided by the power inverters guarantees high performances for all the voltage ancillary services.

In conclusion, FACTS devices can be used to sustain MV networks or to substitute aging devices with lower performances (e.g. D-STATCOM with respect capacitor banks). However, other benefits have to be taken into account during their installation. In fact, these devices can increase the active power flexibility from local resources and support directly the voltage of transmission system. Considering the increasing need of voltage flexibility in transmission system, due to the substitution of transmission generators by distributed ones, the potential flexibility from power electronic devices can seriously be envisioned to support voltage.

Table 10: Capabilities of Advanced power technologies to provide current ancillary services

Current Ancillary service			Transformer		Reactive compensator			Power management		Users support
			Power electronic	MV/LV OLTC	SVC	D-STATCOM	SC	IPC	MV-DC network	STS
Frequency	**FCR**	Direct								
		Indirect								
	aFRR	Direct								
		Indirect								
	mFRR	Direct								
		Indirect								
Voltage	**PVC**	Direct								
		Indirect								
	SVC	Direct								
		Indirect								
	TVC	Direct								
		Indirect								

KEY

	Indicates very good capabilities
	Indicates good capabilities
	Indicates little capabilities
	Indicates very little capabilities
	Indicates no capabilities

Table 11: Capabilities of Advanced power technologies to provide future ancillary services

Future Ancillary service			Transformer		Reactive compensator			Power management		Users support
			Power electronic	MV/LV OLTC	SVC	D-STATCOM	SC	IPC	MV-DC network	STS
Frequency	**FFR**	Direct								
		Indirect								
	FCR	Direct								
		Indirect								
	FRR	Direct								
		Indirect								
	RM	Direct								
		Indirect								
Voltage	**FRTC**	Direct								
		Indirect								
	CMVC	Direct								
		Indirect								
	PVC	Direct								
		Indirect								
	SVC	Direct								
		Indirect								
	TVC	Direct								
		Indirect								

3.3 Quantification of ancillary services provision from distributed energy resources

3.3.1 Flexible resources availability

For the selected flexibility resources, their availability (parameter $\boldsymbol{FlexRes}$ in equation (56)) is assessed quantitatively for the three pilot countries. Depending on the availability of data the current quantitative amount of the resources refers to the publicly published data in 2015 or 2016. For the future (i.e. 2030) however, the selected SmartNet scenarios for the respective countries are used as a guideline to gather the appropriate flexibility amount mostly from either the ENTSO-E scenario development report [115] or EU28 reference scenario [116] . The detailed description of the SmartNet scenarios for 2030 are presented in [1], with one scenario for each pilot country:

- **Italy:** The SmartNet scenario 4 for Italy is based on vision 3 by ENTSO-E. Vision 3 reflects an ambitious path towards the 2050 European energy goals, where every Member State develop its own effort achieving overall 50% of European load supplied by RES in 2030 [117].
- **Denmark:** The scenario selected for Denmark in SmartNet project is Scenario 3 where there is a good cross-border interconnection and full availability of demand response. This scenario corresponds to the Vision 4 of ENTSO-E. Vision 4 (Green Revolution) reflects an ambitious path towards the 2050 European energy goals, with 60% of load supplied by RES in 2030. The flexibility availability data is only for Western Denmark (DK1).
- **Spain:** The scenario selected for Spain in the SmartNet project is scenario 2 where poor cross-border inter-connection and low RES are assumed in 2030. Within the selected scenario, to quantify the availability of flexibility resources in 2030 for Spain is mostly collected from the EU Reference Scenario 2016 [116].

The flexibility availability data can either be the total installed capacity (ICAP) in MW or the total amount of energy generated or consumed (EG/EC) in a year [GWh/year]. Wind Turbines and PV availability data is the yearly energy generation in GWh/year. For stationary and mobile storage and for CHPs, the data format is in terms of the installed capacity in MW. For flexibility resources such as TCLs, industrial loads and shiftable and curtailable loads the data format is the yearly energy consumption in GWh/year. Finally for the stationary storage systems, the DOE Energy Storage Database [118] is used in order to identify the 2015 capacities. For 2030 however, the trends in the respective countries from 2000 to 2016 from the same database is used to project the level in 2030. Accordingly:

- The amount of PHES and Flywheel storage systems will likely be stable: similar volumes are expected in 2030 and 2015;
- Following the global trend (see Figure 22), the electro-chemical (battery) based storage systems amount in the pilot countries is assumed to increase approximately by at least 160%

compared to the 2015 amount[17]. Although the trend shows exponential growth globally from 2009, this estimate is quite cautious since we consider a linear increase in time. In practice, this uncertainty on the storage amount is quite high and sensitivity analyses on this amount should be made for any application using that amount as input to an application/simulation.

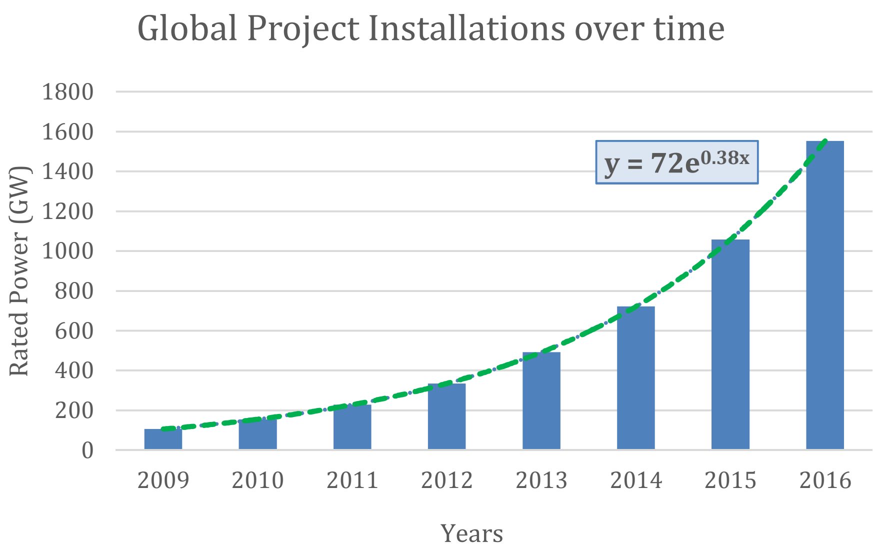


Figure 22: Global trend in electro-chemical storage systems [118]

The share of the flexibility resources connected to transmission versus distribution grid is also identified. When the share is unknown, especially for the data in year 2030, either the current proportion is considered to prevail or the share in known countries is used to divide the lumped quantity between distribution and transmission levels. The values in Table 12 represent the sheer volume of DERs (***FlexRes*** quantity in equation (56)) collected for the pilot countries following the scenarios selected for them, not their estimated flexibility potential (***AvailableFlex*** in equation (56)).

[17]. Only standalone storages which can be used for various applications are considered in this estimation.

Table 12: Flexibility resources total availability data (FlexRes) for the three pilot countries in year 2030

		Year 2030		
		Distribution (MW)	Transmission (MW)	Total MW
Wind T.*	**Denmark (DK1)**	853	2 438	3 291
	Italy	1 261	3 041	4 303
	Spain	5 317	2 907	8 224
PV*	**Denmark (DK1)**	267	0	267
	Italy	6 945	89	7 034
	Spain	5 451	70	5 521
Stationary storage: Battery	**Denmark (DK1)**	*NA*	*NA*	*NA*
	Italy	19	123	142
	Spain	4	0	4
Stationary storage: Hydro	**Denmark (DK1)**	0	0	0
	Italy	817	6 470	7 287
	Spain	11	6 968	6 979
Stationary storage: Flywheel	**Denmark (DK1)**	0	0	0
	Italy	0	0	0
	Spain	1	0	1
Mobile storage	**Denmark (DK1)**	6 000	0	6 000
	Italy	285	0	285
	Spain	2	0	2
CHP	**Denmark (DK1)**	990	825	1 815
	Italy	4 841	13 020	17 861
	Spain	3 719	3 100	6 819
TCL*	**Denmark (DK1)**	306	72	378
	Italy	652	0	652
	Spain	772	0	772
Load shifting*	**Denmark (DK1)**	228	0	228
	Italy	49	0	49
	Spain	37	0	37
Load curtailment*	**Denmark (DK1)**	0	0	0
	Italy	394	0	394
	Spain	NA	NA	NA
Industrial processes*	**Denmark (DK1)**	119	0	119
	Italy	548	137	685
	Spain	72	287	358

* GWh/year values (yearly generated or consumed energy) is converted to MW by dividing it to 8760

3.3.2 Ancillary services provision capacity

Depending on the data type (ICAP, EG or EC) and the type of flexibility resource, we may roughly estimate the ***FLEX*** factor (Equation (56)), which represents the share of the resources able to provide flexibility among the total capacity. One can note that this parameter does not account for the season of the year or the market arrangement. It rather accounts for the sheer amount of flexibility resource from the total installed capacity that is available for service provisioning in general.

For example, in the availability data (Table 12), the expected future total annual consumption of industrial loads is mentioned (similar data about the current 2016 availability can be seen in Appendix C, Table 38 and Table 39). However, not the whole industrial load is available for shifting. According to [59], in average, about 56% of the industrial load is available for shifting, therefore the ***FLEX*** value is set to 56% Table 13 below presents the value of this parameter for the different DER families. Except for EVs

(10%), CHP (90%), TCL (52%) and industrial processes (56%) all the other flexibility resources are assumed to have 100% flexibility of the capacity the resources have.

Table 13: Percentage Sheer volume of flexibility as percentage of the installed capacity or consumption (FLEX%)

Flexibility Resource	Data Format (MW or GWH/Year)	FLEX%	Explanation for the FLEX(%) value
CHP	ICAP	90%	Efficiency of CHP (in case of ICAP) (Heat to Power ratio)
Industrial processes	EC	56%	Percentage of capacity available for shifting (average value for all industries)
Load curtailment	EC	100%	100 % of load shading participation can be assumed. Or can also be specific for each country
Load shifting	EC	100%	100 % of load shifting participation can be assumed. Or can also be specific for each country
Mobile storage	EC	10%	This is the assumed combined percentage of cars plugged-in and also % capacity of battery for charging or discharging.
PV	EG	100%	PV efficiency, location factor for solar irradiation combined in (%)
Stationary storage: Battery	ICAP	100%	% cap available for charging and discharging
Stationary storage: Flywheel	ICAP	100%	% cap available for charging and discharging
Stationary storage: Hydro	ICAP	100%	% cap available for charging and discharging
TCL	EC	5% (Current) and 52% (2030)	% of flexible portion of total consumption
Wind T.	EG	100%	Wind Turbine efficiency

As a reminder (see section 3.1.2), the maximum available flexibility of a specific DER family (not accounting for market conditions, economical aspects or time, season), denoted as $\boldsymbol{AvailableFlex}$ in equation (58), is estimated from:

- $\boldsymbol{FlexRes}$, the total capacity of this resource (MW), which is a **quantitative estimate** based on high-level scenarios.
- $\boldsymbol{MAP}$, the technical capability (%) of the DER to provide a given AS, based on a **qualitative** mapping between DER and AS.
- $\boldsymbol{FLEX}$, the share (%) of the DER family which are able to provide flexibility among the total capacity, which is a **quantitative estimate** based on literature and forecast for 2030.

Therefore, the maximum available flexibilities numbers summarized in Table 38 and Table 39 in Appendix C (fully detailed tables for 2016 and 2030) must be interpreted cautiously, since 1) estimations are based on other estimations for the year 2030, and there is uncertainty in these estimations, and 2) the technical capabilities are qualitatively estimated. In summary, the maximum available flexibilities are indicative figures which can give an idea of the potential of different DER families to provide or not some AS, but they should not be interpreted as accurate numbers.

On top of this, these capacities practically may further dwindle with market conditions (e.g. wind turbines committed to supply certain loads would not have full flexibility) and environmental conditions (e.g. wind and PV generations are not available all the time), lowering their real availability to provide AS to much lower values than the capacities shows in the in Table 14.

The summarized version of the maximum future capabilities of DERs in the three pilot countries as well as the share of DERs connection in distribution and transmission system is presented in Table 14. The first key message is that resources connected to the distribution grid can provide a significant part of services, with a potential of the same order of magnitude than for transmission grid resources. The share of potential in the distribution grid is higher in Spain (about 60% for all services), similar in Denmark (close to 50% for all services), and lower in Italy (about 40% for all services). The maximum availabilities are also specified. However, except for some frequency services (see Table 15), it is difficult to directly compare them to the need of the ancillary services in 2030, since those services have not been quantified (see [1]). For FCR needs, we can observe that the potential is high enough since the whole current needs for continental Europe are 3 000 MW ([1]).

Table 14: Quantitative mapping of flexibility resources to ancillary services in 2030

			From DS	From TS	Absolute maximum potential availability of DERs before subjected to Market and environmental conditions (MW)
Frequency	FCR	DK1	47 %	53 %	4 541
		IT	40 %	60 %	2 7025
		ES	64 %	36 %	17 142
	aFRR	DK1	49 %	51 %	5 074
		IT	37 %	63 %	33 059
		ES	62 %	38 %	19 428
	mFRR	DK1	50 %	50 %	3 937
		IT	33 %	67 %	29 851
		ES	58 %	42 %	15 790
Voltage	PVC	DK1	49 %	51 %	3 161
		IT	39 %	61 %	23 098
		ES	62 %	38 %	13 792
	SVC	DK1	50 %	50 %	3 570
		IT	37 %	63 %	27 116
		ES	61 %	39 %	15 326
	TVC	DK1	50 %	50 %	3 521
		IT	37 %	63 %	26 933
		ES	61 %	39 %	15 225

Table 15 describes the estimated FRRa and FRRm (both upwards and downwards) needs in 2030 for Denmark, Italy and Spain (estimated in [1]) and compares them to the maximum **potential** assessed in this chapter, for resources connected to either the transmission or distribution grid. Importantly, in all cases, the potential of the resources transmission and distribution grid is significantly higher than the reserve needs, from at least 5 to about 30 times. In addition, the volume of flexibility available from the distribution level (resp. transmission level) is large enough to fulfil the required FRR needs. One should note however that this potential is an upper bound on the potential flexibility: in practice, as already mentioned in this chapter, the real flexibility potential is lower and depends on many factors (e.g. primary usage of the DER, previous commitments on energy markets, time of day, season, weather conditions ...). Such aspects are out of scope in this deliverable, but other projects should consider some (extreme, or probabilistic) combination of scenarios about all these factors to determine the real (statistical) potential of DER to provide AS. However, it is quite reasonable to conclude from our analysis that the available flexibility potential is high enough to be confident in the fact that **DER can provide a significant part of AS to the distribution grid** in the three countries considered.

Table 15: Comparison of ancillary service needs and flexibility resources availability in the pilot countries in 2030

Ancillary service needs	Pilot Countries	AS need in MW (2030)	Flexibility resources connected at DS (MW)	Flexibility resources connected at TS (MW)
Frequency Restoration Reserve: Automatic (**aFRR**) :Downwards	DK	257	2 466	2 608
	IT	1 414	12 323	20 735
	ES	669	12 011	7 416
Frequency Restoration Reserve: Automatic (**aFRR**) : Upwards	DK	262	2 466	2 608
	IT	1 471	12 323	20 735
	ES	783	12 011	7 416
Frequency Restoration Reserve: Manual (**mFRR**) :Downwards	DK	334	1 956	1 980
	IT	1 028	9 898	19 953
	ES	5 473	9 118	6 672
Frequency Restoration Reserve: Manual (**mFRR**) : Upwards	DK	426	1 956	1 980
	IT	1 523	9 898	19 953
	ES	3 191	9 118	6 672

4 Network modelling and characteristics

The DER presented in Chapter 2 are connected to different locations of the distribution grids. For instance, PV systems can be located on rooftop of small households or directly at the MV level if they are larger farms. The information about the location of the devices is required by the aggregator in order to see the amount of flexibility that can be provided in specific areas of the distribution network. Moreover, the market clearing processes in SmartNet include a model of the power system physics. In order to complete the market clearing, a model of the grid as well as the location of the bids in this grid needs to be available. Additionally, the effects of the different coordination mechanisms will be assessed based on network simulations.

Therefore, distribution and transmission grid models have to be taken into account in the simulations platform. These models have to be as close as possible to the real grids so network operators have been requested to share them.

In upcoming sections, we propose a general modelling framework for distribution networks. Then the main characteristics of the networks provided by the DSOs (NYFORS for Denmark and EDYNA for Italy) and TSOs (ENERGINET.DK for Denmark and TERNA for Italy) are presented. At the time of writing this deliverable, no information has been provided for the Spanish distribution network. Instead, a representative network based on an IEEE model is proposed.

4.1 Distribution networks modelling

Distribution networks models are approximations of the real networks intended to be valid for a specific set of purposes. They are 'the mathematical descriptions of specific electric system components formatted in a manner suitable for use by the particular simulation tool for which it is intended' [119] The simulations which will be performed later consist mainly in Power Flow and Optimal Power Flows (OPF) calculations. Dynamic, slow-dynamic or transients models for power quality, protection and stability analysis are out-of-scope. Moreover, due to the intermittent nature of VRES simple static calculations using the peak power are not sufficient. Quasi-static simulations using time-series are instead preferred since they allow capturing the stochasticity of the DERs.

For most of the conventional elements of a network, mature models already exist and they are easily accessible in any power system simulations software. For instance, the line model for quasi-static simulations is widely known and the parameters requested for load flow calculation are clearly identified. However when it comes to modelling recent power system components, significant differences can be observed between models. A particular attention should be given to the modelling capabilities of software as well: for example, droop-based voltage controls for generators are widely spread but they are not supported by the power system simulation software used in the simulation platform.

Another important aspect of the modelling is the phase balancing of the distribution networks: it is generally acknowledged that the MV level is balanced over the three phases since network operators invest a lot of effort to balance their low voltage network. Considering this assumption as well as the fact that the LV parts are not modelled due to the lack of data (this will be discussed further in the next chapter), we will use the single-line diagram representation and the MV buses will be the smallest spatial unit for flexibility resources connection. In the next sections, we present briefly, the main apparatus used in distribution networks.

4.1.1 Cables and lines

The Π-model is used to represent lines and cables. It includes a series impedance Z_{km} and shunt admittances y_{km}^{sh} at each end of the line, as depicted in Figure 23. The series impedance is characterized by a series resistance R_{km} and series reactance X_{km}. The shunt parameters are the shunt susceptance $G_{km}^{sh}$and the shunt conductance B_{km}^{sh}.

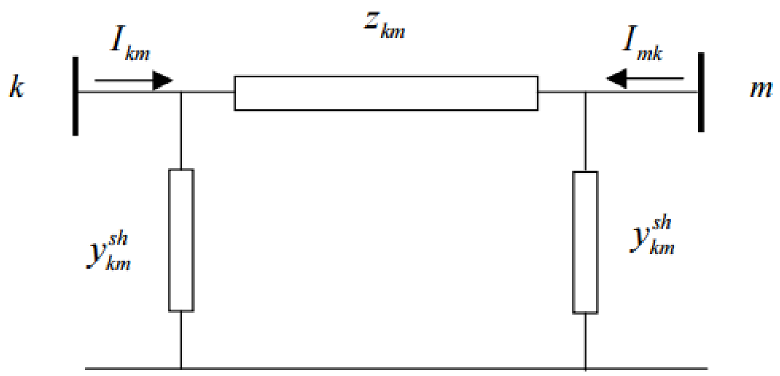


Figure 23: Π -Model of a line between nodes k and m [120]

Due to the types of calculation performed, the positive-sequence parameters of the lines resistance, reactance and the total susceptance will be used only. Concerning the conductance B_{km}^{sh}, it is neglected in the modelling of the distribution grid since it is acknowledged that this parameter is usually considered for transmission network only. Additionally, the number of parallel lines, their length as well the maximum rated current (i.e. the line capacity) are considered in the network model.

4.1.2 Connecting elements

The network topology (radial or meshed operation) is an important information when modelling networks. For instance, some load flow algorithms are only able to converge with radial topology. The knowledge of the position (open or close) of the following elements is requested:

- Switches

- Couplers
- Circuit-breakers

These components are represented from a pure topological point of view and any electrical parameter is discarded. This assumption is made valid by the fact that we perform static simulations and that detailed modelling of the protection/connection devices is generally used for dynamic simulations only.

4.1.3 Transformers and On-Load-Tap-Changers

Considering that the LV network segments are discarded due to the lack of data, the only parameters of MV/LV transformers considered will be the transformer rating. For the primary substations transformers (HV/MV transformers) which are usually On-Load-Tap-Changers (OLTC), the following parameters are needed:

- Transformer rating
- Transformer ratio
- Winding
- Tap changer range
- Tap changer resolution
- Nominal tap position

4.1.4 Buses

In Power System analysis, the buses are associated with four quantities: the voltage magnitude, the voltage phase angle, the active power and the reactive power. In static simulation (load flow), two of them are known (fixed) and the others are calculated. The buses can be classified into three categories:

- **PQ** or Load Bus: the active and reactive power are known and the voltage magnitude and angle are unknown. They are normally used to represent load buses and small DRES without voltage control capabilities.
- **PV** or Generation Bus: the active power and the voltage magnitude are known. This is generally the case for large generators imposing a constant voltage at the connection point (with Automatic Voltage Regulators) but it can also apply for small VRES such as rooftop PV with a droop-based local voltage control.
- **Uθ** bus or Slack Bus: also called the reference bus, it is the reference of the voltage angle reference and it is used to balance generation, load and losses.

For the normal network operation, the allowed voltage band lies between +/- 10 % for the entire MV and LV network. Each DSO sets the limit of both levels according to its network characteristics. In case the MV part is decoupled from the LV through a secondary substation OLTC for example, this voltage band can be extended to +/- 10 % for each level [121].

4.1.5 Loads

Loads can be modelled with the 'ZIP' model as constant impedance, constant current or constant power. Table 40 (Appendix D) presents the type of model to be used for the most common loads. For the sake of simplicity, we make the assumption that all loads are modelled with the constant power model. It is a realistic approximation since all the devices which not able to provide flexibility are aggregated and modelled as the resulting power injection (this topic will be addressed more in detail in the upcoming chapter).

4.1.6 Generators

In distribution networks, most of the generators consist of small VRES such as Wind Turbines or PV but smaller conventional groups can be found as well. More recently, the amount of CHPs have also increased. For the quasi-static simulations, the active power injected by these generators is considered as constant as well as the voltage at the point of connection, provided that the generators possess reactive power control capabilities and are sufficiently large. The reactive power injection can only operate within the limits delimited by a capability curve (Figure 4).

4.2 Characteristics of the distribution networks in pilot countries

The distribution networks must be large enough to ensure that the simulations are relevant, particularly in order to be able to compare volumes of flexibility provided from the different voltage levels (transmission and distribution) but also to create a competition between actors of different sizes. In the Italian case for example, the physical area in which EDYNA is realizing its pilot is relatively limited (it contains one primary substations and eight MV feeders only) and is probably not large enough to guarantee that the results are sufficiently representative to draw meaningful conclusions. As for the pilots covered by the Danish and Spanish cases, they are also relatively limited in size. As a consequence the network operators were asked to provide network models that are as detailed and as large as possible, not only limited to the pilot.

DSOs have been requested to provide information on the different elements of the distribution system at the MV level, but also they were asked to provide, as far as possible, detailed information about their LV network since an important share of the flexible resources are connected to this level.

Despite the efforts undertaken by the partners, some data could not be extracted for technical reasons or for confidential purpose in the case of ENDESA. The following section presents the main characteristics of the distribution networks in Demark, Italy and Spain.

4.2.1 Danish case

4.2.1.1 Main characteristics

NYFORS is a distribution network operator who supplies approximatively 45,000 customers over its area. It is located in northern Denmark.

The model provided covers the entire distribution area of NYFORS that contains sub-transmission and distribution levels. Even if the detailed characteristics of the LV network model is out of the scope, NYFORS provided metadata of each secondary substation (MV/LV transformer) such as the different types of customers (load and generation) located downstream.

NYFORS operates its network in three different voltage levels: 60 kV for the sub-transmission part, 10 kV for the MV level and finally 0.4 kV for the LV level. It contains approximatively 1500 nodes, 1600 lines and 1300 transformers in the high-voltage (sub-transmission) and medium voltage parts. The sub-transmission network contains 58 nodes and it has the particularity to contain two distinct zones: west and east. The eastern part is meshed and two loops can clearly be identified on the single-line diagram (Figure 34 in Appendix D). A majority of overhead lines are found in this part of the network. Most of the large wind farms and CHP are connected to the 10 kV network through dedicated feeders. The 10 kV network is operated radially.

Table 16 below presents the transformers found in the network by voltage level and the total transformed power.

Table 16: Overview of the transformers found in NYFORS network

Voltage transformed (kV)	165 / 60	60 / 10	10 / 0.4
Number of transformers	4	27	1 309
Total power transformed (MVA)	445	351	408

4.2.1.2 Potential flexibilities

The information on the different types of generation sources is aggregated for the entire distribution area. For instance, the production from wind turbines is important in the area since a little bit less than 260,000 MWh of electricity is produced by them yearly. Considering a load factor of 25% results in an estimated 120 MW of installed capacity on the 10 kV parts. The generation connected to 60 kV is about 30,000 MWh, equivalent to a 14 MW capacity.

Denmark is one of the leading countries in the use of CHP and more than 95% of the residential heating is provided by this mean. In the NYFORS area, CHPs have produced approximatively 72,000 MWh of electricity in 2014 according to measurements. Considering a minimum of 5000 hours of operation and a 90% efficiency, this yields to an approximated installed capacity of 16 MW for the CHP. Therefore the potential of flexibility from these sources is considerable.

4.2.2 Italian case

4.2.2.1 Main characteristics

EDYNA is a network operator located in the north of Italy, in the region 'Trentino Alto Adige' and more precisely in the Province of Bolzano. Their network covers a geographical area of 7400 km^2 and it supplies approximatively 95000 LV and 580 MV customers. The pilot itself covers one primary (HV/MV) substation with eight MV feeders.

The network is mostly operated in 20 kV but there are some exceptions with a few sections partly electrified in 10 kV. Just like the other DSOs, the LV level is exclusively operated in 0.4 kV. According to EDYNA, the network is operated radially and the configuration is not changed seasonally.

Table 17: Overview of the transformers found in the EDYNA network

Voltage transformed (kV)	132 / 20	20 / 0.4
Number of transformers	29	2155
Total power transformed (MVA)	800	465

The conducting material of the lines encountered in the network consist of Aluminium (60%), Copper (36%) and a marginal proportion of Aluminium Steel. The electrical characteristics of the cables provided for the area restricted to the pilot allowed the identification of twelve different types of cables. An equal share of overhead lines and underground cables is found.

4.2.2.2 Potential flexibilities

The mountainous area of Trentino Alto Adige is characterized by its low population density and the predominance of electricity generation by hydro power (not only large central connected at the transmission level but also small ones connected at MV and LV levels). Table 18 below summarizes the number of customers (both producers and consumers) found in the pilot area at present time.

Table 18: overview of the potential flexibility sources in the Italian pilot area

	Generators	Loads
LV	○ Installed PV capacity=722 kVA (27 groups from 2.75 kVA until 127 kVA, average of 36 kVA) ○ Hydro plants: 2 units with (75 kVA in total) ○ Conventional groups (thermal): 4 units (64 kVA in total)	2425 LV customers among which: ○ 6.74 MW of residential customers ○ 163 kW of public lighting ○ 8.85 MW of remaining load
MV	○ Hydro plants: 21 units (32 MVA in total) One PV plant of 0.150 MVA ○ Two conventional (thermal) groups: 2.07 MVA in total	40 Loads (28 MW in total)

4.2.3 Spanish case

4.2.3.1 Data availability

Although at the time of writing the deliverable the actual network data is not yet available, it is expected that a simplified grid model for an area delimited by six primary substations located in the city of Barcelona will be used. The list of the Primary Substations is a follows: Maragall, Besós, Vilanova, Tanger, Hostafranc and Sanllehy.

The type of information that will potentially be used for the Spanish case within SmartNet in an aggregated way includes:

- The network topology (switches positions);
- The nominal voltage of the nodes;
- The detailed characteristics of the following elements will be provided as well:
  - Electrical characteristics of the network components (lines, cables, transformers, capacitor banks)
  - Nominal power of the loads
  - Type and characteristics of the flexible assets
- The planning and operational rules:
  - Voltage band allocation for the MV level;
  - Normal operational plan

4.2.3.2 Representative network of the pilot area

The following test network, representative of a typical urban network of the Spanish pilot area, can be used to generate an artificial network in order to perform simulations.

An attempt to modify a standardized IEEE network in order to fit as much as possible to a typical network of the area of Barcelona was done in [122]. The IEEE 37 bus system was selected mainly on the basis of its length. Several parameters such as voltages and impedances of the IEEE 37 node test grid were changed (for instance the network was adapted to 25 kV and the lines are adapted to an underground system). An overview of the network characteristic if provided in Annex D.

4.3 Characteristics of the transmission grids

TSOs from the three countries were requested to share their network model in order to perform simulations. An equivalent but simplified version is available online for Denmark [123]. It was used for the grid modelling with some small adaptations. For Spain, only the DSO ENDESA is involved in the project therefore it was not possible to get the real transmission grid from the Spanish TSO REE. Finally for Italy, TERNA wasn't able to share the network model for confidentiality purpose, therefore an old version of the network has been used instead.

4.3.1 Danish case

The transmission grid operated by ENERGINET.DK contains approximatively 300 busses and 420 branches. This network has the characteristic to be divided into two separated transmission grids of comparable size, interconnected trough an HVDC link (Figure 24). The Western part of the grid is mostly connected by AC to continental Europe, while the Eastern part of the network is the connected by AC to the Scandinavian peninsula. However, both parts are connected to the other nations by means of HVDC cables.

Besides, the networks have also the role of transmitting the power from northern Europe to Central Europe. This can be seen by examining the total HVDC interconnections which, considering also the connection between the two subnetworks, reaches more than 5 GW capacity. As a consequence the Danish power system is very dependent from the neighbouring power systems and the Western and Eastern areas are partly independent regarding the frequency regulation. Due to these characteristics, it has been decided to consider the Western part only (where the distribution grid operated by NYFORS is located) in order to reduce the complexity of the problem. Finally, it is expected that in the future the frequency regulation will be made not only by internal resources, but also taking advantage of the external resources of the neighbouring countries by means of the large interconnection capacities of the network.

Table 19: Main characteristics of the Danish transmission grid [123]

	Units of measurement	Value
Substations	No.	185
Overhead lines	km	4 900
Cables	km	1 900
Interconnection 2014	MW	5 500

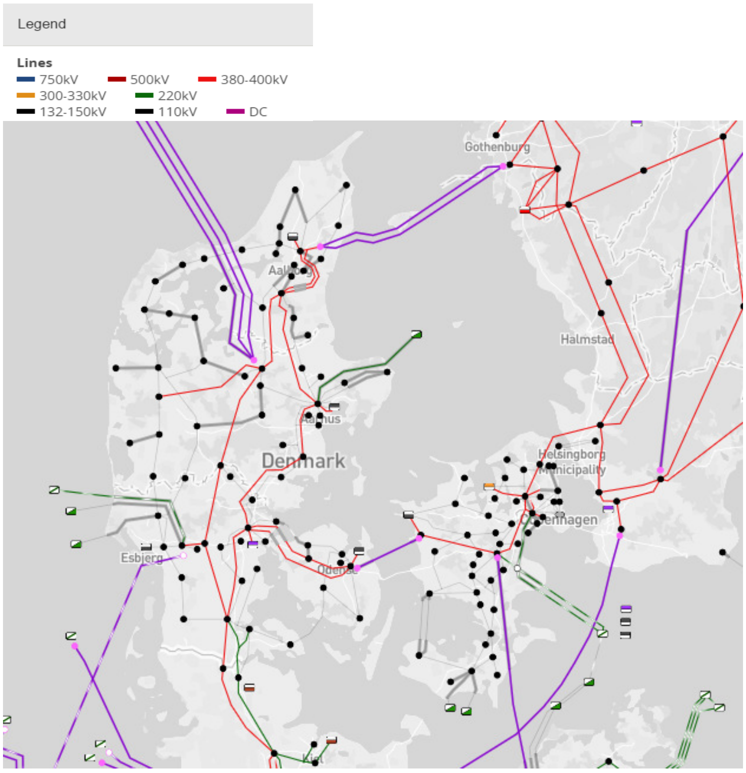


Figure 24: Simplified map of the Danish transmission network [124]

4.3.2 Italian case

The Italian transmission grid operated by TERNA contains about 5800 busses, 6800 branches and 850 generators. It contains the entire high voltage network, including the sub-transmission parts, as shown in Table 20 below.

Table 20: Main characteristics of the Italian transmission grid

SUBSTATIONS	Units of measurement	Value
380 kV		
Substations	No.	159
Power transformed	MVA	109 508
220 kV		
Substations	No.	150
Power transformed	MVA	30 692
Lower voltages (≤150kV)		
Substations	No.	541
Power transformed	MVA	3 815
Total		
Substations	No.	850
Power transformed	MVA	144 015
Bays	No.	6 108

LINES	Units of measurement	Value
380 kV		
Line length	km	12 118
220 kV		
Line length	km	11 721
Lower voltages (≤150kV)		
Line length	km	48 760
Total		
Line length	km	72 599

However, the available dataset does not take into account the very last upgrade of the south region. Besides, it is difficult to foresee where the new generation will be located in the 2030 scenario, in particular for wind generators, and so the necessary development of the transmission grid in southern parts. Finally, the Italian network is divided in different zones with limited capability power exchange. From these observations and since the pilot project is located in the North of Italy, we decided to discard any part of the network located below the central Italian region illustrated by the red line in Figure 25. It can be observed from Figure 37 (Annex D) that this limit corresponds to the boundary between the market areas with lowest capacity (about 2 GW).

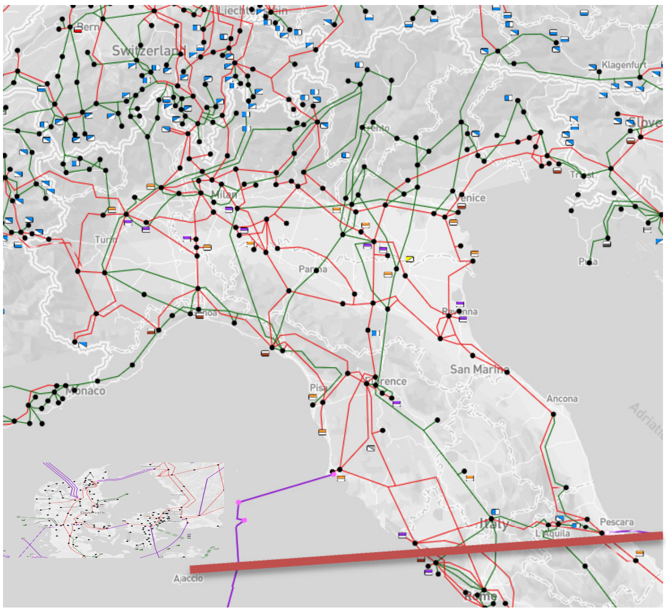


Figure 25: simplified map of the North Italian transmission network and the division with the other parts [124]

This reduces the complexity of the problem in terms of size to 3900 buses, 4500 branches and 650 generators, but it is possible that this reduced model does not represent the real behaviour of the network. In fact, the available data refers to one screenshot of the network, but the network operation and the topology can change based on the daytime, the season and the type of day. Thus, during the definition of scenarios, the network could be further simplified, representing in details only the area closely located to the distribution network of EDYNA, for which more information is available.

4.3.3 Spanish case

The Spanish transmission grid which is modelled possesses approximatively 2000 busses, 3000 branches and 700 generators. Table 21 presents its main characteristics. It is noteworthy that the Spanish network is more meshed with respect to the Italian network, mainly due to the geographical differences between the two nations (the Spanish network is centred around Madrid and the branch/busses ratio is equal to 1.5 for Spain and 1.15 for Italy). The higher number of interconnections makes it harder to isolate specific areas within the grid like it was done for Italy. Depending on the necessity of the simulation, the areas of the network remotely located from the pilot could be further simplified.

Table 21: Main characteristics of the Spanish transmission grid

SUBSTATIONS	Units of measurement	2015
380 kV		
Bays	No.	1,441
220 kV		
Bays	No.	3,124
Lower voltages (≤150kV)		
Bays	No.	863
Total		
Bays	No.	5,428
Power transformed	MVA	84,544

LINES	Units of measurement	2015
380 kV		
Line length	km	21,179
220 kV		
Line length	km	19,387
Lower voltages (≤150kV)		
Line length	km	2,420
Total		
Line length	km	42,986

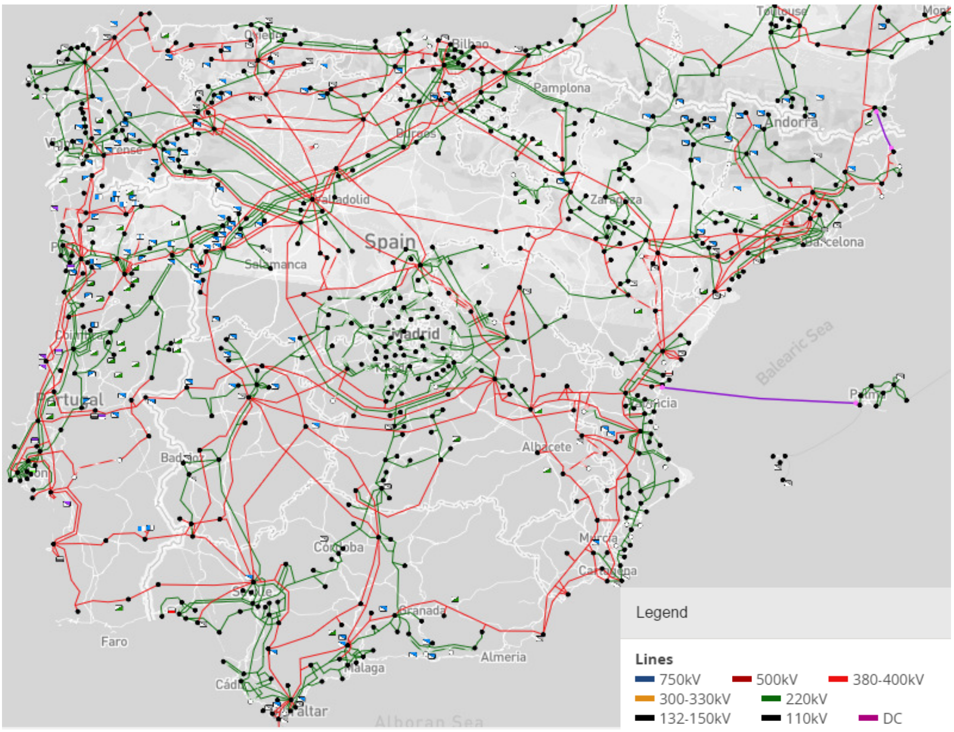


Figure 26: simplified map of the Spanish transmission network [124]

5 Methodology for the generation of scenarios in distribution networks

As explained in the previous chapter, a tractable model of the distribution network is required for each country in order to perform the simulations. It contains the electrical characteristics of the main components which can be found in a network and the way these elements are linked to each other (in other words the topology). Nevertheless, additional information has to be specified for the simulations such as the size and location of the loads and generators (and more generally of the different DER).

The overall amount of flexibility of each resource (flexible or not) connected to a certain distribution network must be in line with the future scenarios defined in [1], in other words we must build an image of the present distribution networks for 2030. For instance, the future installed PV capacity is the result of the current situation in the network and the growth rate expected for the future scenario. Once the total future capacity is determined for each DER, it has to be allocated to different network locations in a realistic way (i.e. by respecting the planning and operation rules). In addition, the result of this exercise should lead to interesting scenarios for the simulations: since one of the objectives of SmartNet is to assess the possible impact of the flexibility activation in networks, the amount of flexible resources and their location have to be rigorously selected to ensure that loading or voltage constraints violations can eventually occur in certain conditions.

For the simulation needs, flexibility resources should also be available in other distribution networks and not only in the region of the pilots. Some additional constraints such as the lack of network model must be considered as well in this case for the design of the methodology.

In the upcoming sections, we introduce a high-level methodology that enables specifying the size and the location of the different flexibility resources in distribution networks, according to the future scenarios developed for Denmark, Italy and Spain. Chapter 5.1 illustrates the main challenges related to the down-scaling while Chapter 5.2 describes the methodology in two steps: firstly the detailed scenario specification is detailed in 5.2.1 and then the projection on distribution networks is explained in 5.2.2.

The required inputs are the distribution network models, the quantity of DER for the future high-level scenarios and the information provided by the utilities. The methodology is oriented for the distribution network but it can also be used for the transmission grid to a certain extent. It is intended to be applied later when data scenarios are created for the simulations. Figure 27 below illustrates the required inputs and outputs.

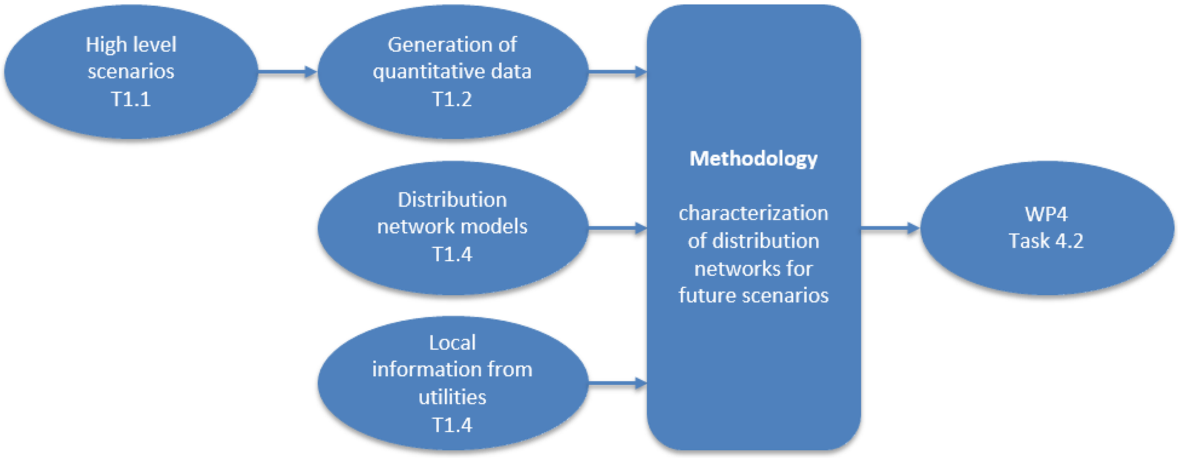


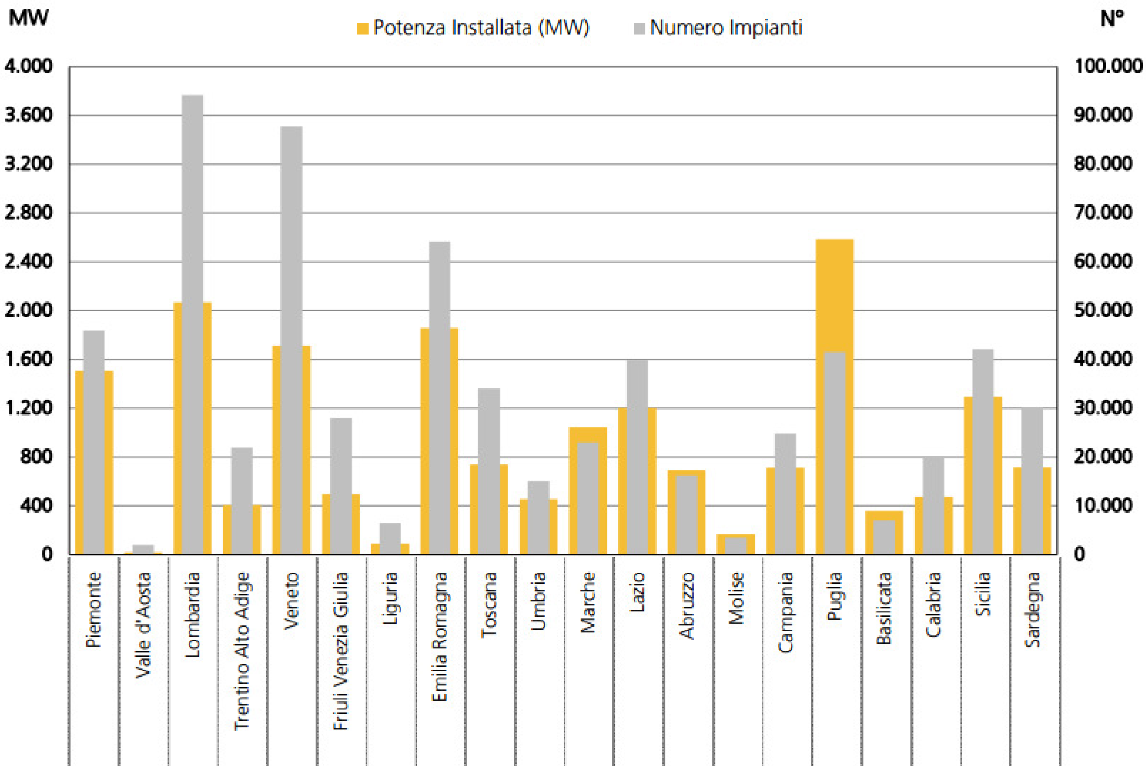
Figure 27: Context of the methodology

5.1 Down-scaling and spatial resolution problematics

The total amount of each flexibility resources must be consistent with the high level scenarios. In Italy for instance, the production from RES is expected to increase for 2030 (see 3.3.1); therefore the installed RES capacity in the distribution network of EDYNA should increase as well by 2030 compared to the current situation. Nevertheless it would be inaccurate to simply downscale uniformly the high-level scenario designed for an entire country to smaller distribution areas since important disparities are observed among countries. Figure 28 shows that the existing PV generation is rather located in the southern and sunny regions of Italy whereas the mountainous region of South-Tirol (i.e. 'Trentino Alto Adige'), where EDYNA is located, is very suitable for the hydro power generation (Table 22). It is clear then that the scenarios must be interpreted by considering the regional specificities of each distribution area to be simulated.

Table 22: Hydro Power generation in 2010 per region (GWh) [125]

Piemonte	6,886.2	Friuli Venezia Giulia	2,035.3	Marche	707.7	Puglia	2.4
Valle d'Aosta	2,947.4	Liguria	253.0	Lazio	1,423.8	Basilicata	519.7
Lombardia	11,415.9	Emilia Romagna	1,150.2	Abruzzo	2,037.6	Calabria	2,113.5
Trentino Alto Adige	10,323.6	Toscana	1,032.8	Molise	292.4	Sicilia	143.6
Veneto	4,511.2	Umbria	2,089.7	Campania	825.4	Sardegna	405.3



	Piemonte	Valle d'Aosta	Lombardia	Trentino Alto Adige	Veneto	Friuli Venezia Giulia	Liguria	Emilia Romagna	Toscana	Umbria	Marche	Lazio	Abruzzo	Molise	Campania	Puglia	Basilicata	Calabria	Sicilia	Sardegna
N°	45.880	1.944	94.202	21.906	87.794	27.967	6.549	64.214	34.048	15.080	23.053	39.897	16.297	3.516	24.827	41.527	7.068	20.279	42.148	30.222
MW	1.505	21	2.067	407	1.715	498	91	1.859	740	457	1.044	1.203	693	167	712	2.586	359	474	1.295	716

Figure 28: regional distribution of the PV capacity in terms of power and number of units [126]

In a next step the total amount of flexibility calculated for the different areas must be projected on the physical network model. Two different ways of proceeding are mainly used [127]:

- **Uniform building**: it consists in connecting uniformly the additional units at various locations in the grid and with random size. Although this option requires the minimum resources in terms of preparation, it will for sure not lead to solution realistic setting for the simulations;
- **Site-by-site building**: By including local information provided by utilities (such as the network model, planned connections, metadata, measurements, GIS, etc.), we can find the most appropriate location for the additional units to be connected. This second option is the most demanding in terms of preparation, especially given the large size of the networks. Usually the site-by-site building is used by transmission networks operators on smaller portion of networks (resulting in a limited possibility of locations) and for large power plants. The main drawbacks of this method is that it highly relies on the data quality.

In the next section, we present a methodology which can be used to create scenarios for the distribution network. In a first step, the acquisition of the overall amount of each flexibility resources in a specific distribution area is detailed step by step. In a second step, the challenges related to the projection on distribution networks are described and solutions are presented.

5.2 Proposed methodology

The first step consists of gathering as much information as possible about the current and future assets of the network and downscale it to the geographical area limited by the DSO. In the second step, the future data obtained from the information gathered is projected on the distribution network model based on local information provided by the DSO.

5.2.1 First step: Detailed scenario specification

In this first step many different types of inputs are used in order to create a picture of the network area at the horizon of 2030. The distribution network is approximated as a copperplate, where any electrical parameter or equipment (such as lines, transformers, switches, etc.) is discarded. Information such as the installed capacity and number of units per renewable energy source, or the number of residential households are used but without considering their location/connection point on the network in case this information is available.

The process is a composed of three consecutive sub-steps where the spatial resolution is increasing (zooming from the country level to the network area). Both current and future (forecasted) data can be used in each sub-step (this is the reason why the temporal axis is not represented in Figure 29).

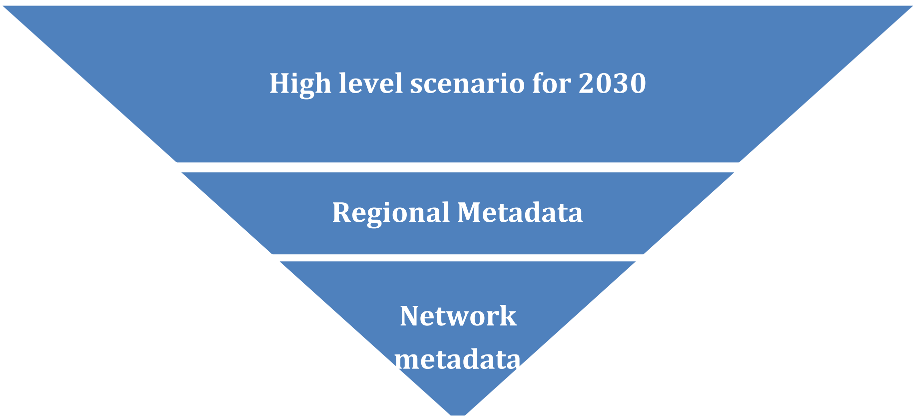


Figure 29: Information gathering process and generation of indicators

- **Sub-step 1.1: Quantification of High-level scenarios**

The high-level scenarios are essentially composed of qualitative information but they have been interpreted to quantify the flexibility in order to calculate the ancillary services provision capacity (3.3). Quantitative values are proposed for each category of DER at country level in the time horizon 2030.

In addition to the scenario specification, this step will consider any additional information potentially useful such as the load growth, the incentives to develop a technology... For example in order to define the quantity of TCLs in the households it can be very useful to access the information on the level of acceptance of consumers for DSM; if a certain percentage of households is willing to have an active behaviour (e.g. for economical or environmental motivations), these individual customers are likely to provide flexibility services (via an aggregator). The information can directly target the installed power (e.g. future PV capacity in Italy in 2030) or indirectly add valuable information to project a future amount (e.g. a decrease in the Li-Ion batteries price is observed so it is very likely that that battery based on this technology will be more used in the future). It can be qualitative or quantitative and reflect an economical, technical or societal trend.

- **Sub-step 1.2: Down-scaling at regional level**

Due to the large spatial extent of the information previously obtained (country level) and the regional disparities, the data cannot be simply down-scaled to the region surrounding the distribution network. Therefore any information concerning the region must be used to complete the projection such as:

- Regional availability of DER: e.g. high share or hydro, offshore wind parks, Combined Heat and Power (CHPs) plants;
- Natural resources availability like irradiance and wind measurements;
- Geographical information: mountainous region or coastline, densely populated or rural area;
- Environmental information: outside temperatures;
- Information on the households: type of heating (electrical radiator, heat pump), cooling, hot water system (urban hot water)

Contrary to the previous sub-step, future projections at regional scale for 2030 are harder to find because they are usually done at country level. The future picture of the power system at the national level and its current situation at regional level must be merged in order to achieve a future grid scenario at regional level.

- **Sub-step 1.3: Down-scaling to the distribution areas and MV/LV level**

The information obtained at regional scale encompasses both the transmission and distribution networks since the regional scenario is valid for the power system. At this point it becomes necessary to split the information between these levels by means of other source of information like the share of resources between the transmission and the distribution level or the grid codes for example.

The projection is refined again by improving the spatial resolution up to the distribution area level (for instance to the pilot area).The network is still considered as a copper plate and only metadata such as the number of customers, the number and size of wind parks, etc. is used.

The target information about each DER family is also coupled with the current metadata of the MV and LV levels (e.g. the number of residential households, the population, etc.). In addition, the rated power of primary substations transformers can be used as an indicator of the amount of loads/generation that the network can host. The actual location of these devices in the network are still not considered, it is rather used in the second step.

5.2.2 Second step: projection on the distribution networks

In the second step, the information obtained for each asset has to be allocated in different locations of the networks. The objective is to create a realistic portfolio of flexibilities at different locations of the grid with a level of detail that match the simulation model capabilities.

5.2.2.1 Constraints related to the spatial resolution

The new connections have to take into account also the network management as they cannot jeopardize the network operation. However, the usual fit and forget rules cannot always be applied, since 1) it is expected an advancement of the network operation and few network reinforcements and 2) one objective of the simulations is to evaluate the effect of an activation of flexibility products, therefore congestions or overvoltage should potentially occur [18]. In order to obtain the most realistic results, the resources must ideally be attached at each single MV bus, which is the smallest spatial unit for the connection point.

Nevertheless, building-out the network with such a level of detailed would require an important effort in terms of preparation due to the large size of the networks considered. The site-by-site projection method requires homogeneous, accurate and detailed information, which is only the case for limited areas (for some distribution areas, no electrical model is available or no information about the existing customers is available for instance). Thus, alternative ways of allocating the flexibility have to be defined in order to find a compromise between the accuracy needed for the simulations and the efforts spent to create the network scenarios given the heterogeneity of data. The solution we propose consist in using different level of spatial resolution to model the distribution network.

5.2.2.2 Multi-level spatial resolution modelling

Since the LV network model is not considered, any information contained downstream will be grouped at the upper level, i.e. at the primary side of the MV/LV transformer. This implies that all constraints potentially occurring on the lower voltage parts are discarded: this is a strong assumption which is for sure not always valid and which can also bring distortions in the results but it considerably simplifies the network. This grouped information will be referred as the '*Equivalent LV network*' as illustrated in Figure 30. In the equivalent modelling of the LV downstream information, the devices are grouped into two categories: the flexibility devices that are able to participate to the AS provision (indicated in green in the figure), and the remaining devices (indicated in red). For the sake of simplicity, these latter will be grouped and modelled as a net active power injection. It is essential for the aggregator

[18] In case few constraints are detected, artificial constraint will not be enforced for simulations purpose. Instead, one conclusion could be that constraints are very scarce.

to have the control of each single device and it would not be equivalent in terms of flexibility to group all the devices of the same family into one single device. Therefore, all resources that can partake to the provision of flexibility will be modelled individually based on Chapter 2.

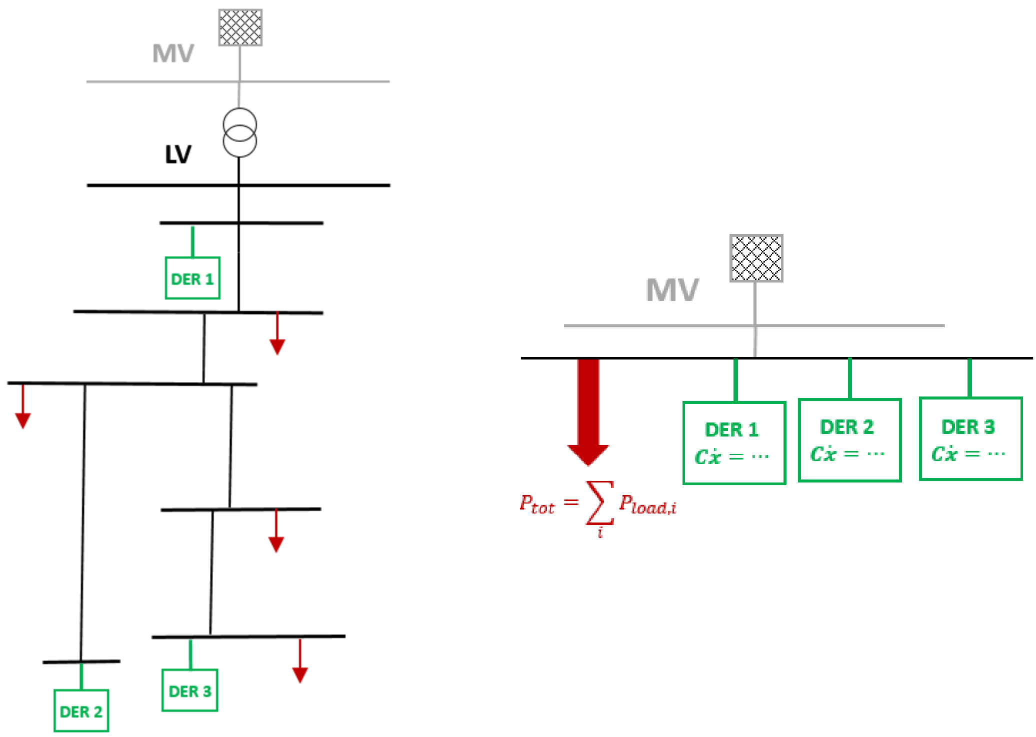


Figure 30: Original LV network (left) and Equivalent LV network (right)

The proposed approach consists in using different levels of resolution to model the different distribution networks to be simulated. The smallest spatial unit considered is a MV node (or its *Equivalent LV network* in case a MV/LV transformer is attached to it) but it can range to a complete distribution network (in case the network model is not available). Three levels of resolutions are used to model the network (high, medium and low resolution). The main principles are listed hereafter for each of them:

- High resolution

In these areas, information is provided on the resources connected al the MV and LV level. It is typically a network for which the quantity of customers (residential, industrial, etc.), the size and the different types of generation sources are known.

A site-by-site projection is made possible for a large zone (e.g. one distribution network or several MV feeders). The electrical parameters of the devices are considered and the power flows and the voltages can be evaluated. Figure 31 below shows the representation of a network in high-resolution.

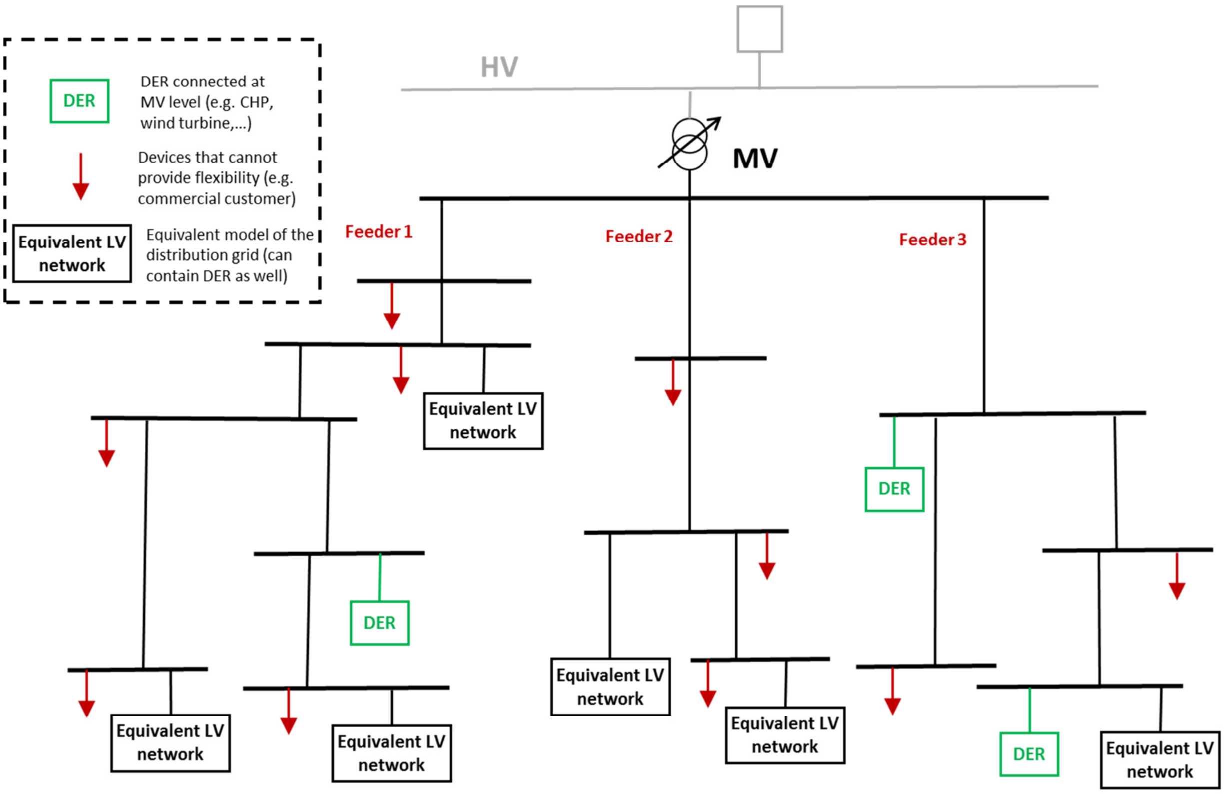


Figure 31: Network represented in high-resolution

- Medium resolution

Medium resolution areas are typically networks for which the MV network cannot be discarded (because it contains weak points), but data accuracy (on the existing flexibilities resources) is not good enough to allocate the resources at each MV node. Therefore only the feeders which are the most likely to overcome constraints are modelled with accuracy and the remaining ones are considered as copper plates. They are selected based on a sensitivity analysis which allows identifying the weak likes or the zones in which voltage variations are high for example. The resources are allocated at each MV node (or to the Equivalent LV network in case a distribution transformer is existing) that belongs to the feeders. Although the site-by-site building (see 5.2.1) is more complex compared to the high-level resolution areas, by limiting the projection to one feeder we considerably reduce the complexity of the exercise.

For the remaining feeders, we apply the same principle as for the *Equivalent LV network*: that is to say the entire MV and LV levels are considered as copper plates and the resources are split in the two groups. The DER which are inside the feeders will be able to provide flexibilities and to participate to the market, nevertheless their impact on the network is not evaluated. The main advantage is that a uniform building can be applied in these areas and it allows the comparison between the transmission and distribution. Figure 32 represents the equivalent model of a medium resolution network.

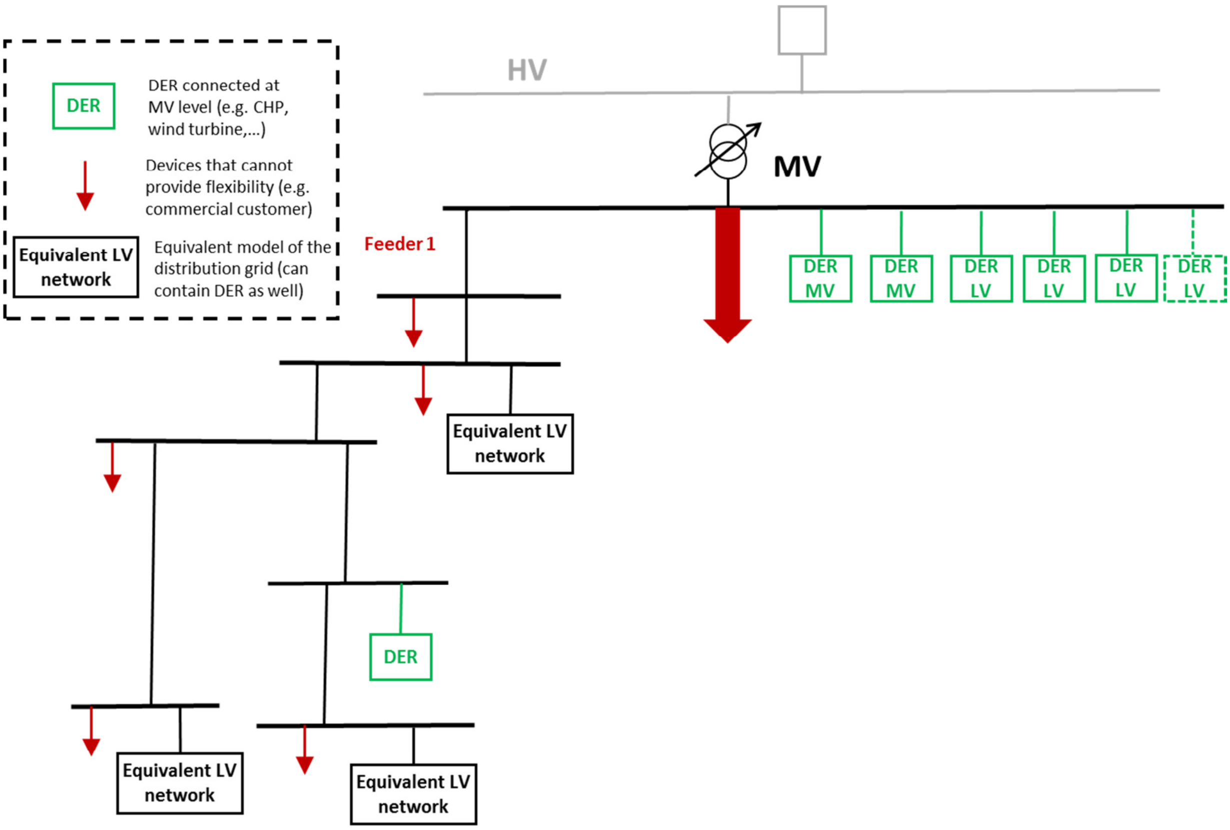


Figure 32: Network represented in medium resolution

Besides, medium resolution zones can be used in order to consider network constraints in the area for which no network models are available[19], e.g. for the distribution areas not operated by the DSO involved in SmartNet (by considering network constraints in an synthetic feeder for example).

- Low resolution

In these areas, the DER can provide flexibility but all the network electrical characteristics are discarded. All devices are connected at the HV side of the primary substation and they can provide flexibility. Eventually, the power flowing through the transformer can be limited (based on the rating of the latter for instance) in order to make it more realistic. The quantity of flexibility must be carefully selected in order not to create market distortion with other markets subject to constraints for example.

[19] If the area is not supplied by the DSO or if the model is not available for instance, then an artificial model has to be created.

6 Conclusions

In the context of this report, the provision of ancillary services by DER has been analysed thoroughly. For each family of flexibility resource, a mathematical model describing their dynamics as well as the related constraints and flexibility costs framework has been proposed.

In order to quantify the potential provision of AS for each pilot country (Denmark, Italy and Spain), and for current and future scenarios, a method has been developed. It combines the technical capabilities of each device (assessed qualitatively), their availability as well as the installed capacity of each resource in the three countries. An overview of the tools and the main results are presented in the report.

Moreover, a modelling framework for distribution networks has been proposed and the main characteristics of the transmission and distribution grids obtained from TSOs and DSOs have been presented. In addition, a methodology was developed to create future scenarios for distribution networks.

The main conclusions and key messages are the following:

- A **framework to specify the flexibility cost of a DER** has been put in place (Chapter 2), focusing on pricing active power (because the focus was on marketable ancillary services), which **can be used by other agents** (aggregators, retailers, BRPs, system operators) to have a good estimate of the cost and how much they need to pay for this flexibility. As an example, an aggregator can use this information to be able to bid at the most accurate price (marginal price).
- A **simplified model of each DER family** was provided (Chapter 2), **describing the dynamics** of the resource (if any), as well as **technical constraints**, such that the DER owner, or an external agent (an aggregator) can retrieve the available upwards and downwards flexibility available for the short-term future, which helps him to determine the flexibility quantity to offer on the AS markets.
- **Resources from the distribution grid are, as a whole, technically capable** (Chapter 3) **of providing any AS**, at current time but also in the 2030 scenarios.
    - The most flexible devices are stationary storage devices (pumped-hydro storage and batteries), because of their availability and their very good technical capability due to the inverter coupling. They are able to technically provide all the AS addressed in this deliverable. CHPs, TCLs and industrial shiftable loads have also good performance thanks to their similarities with storage and their monitoring.
    - VRES such as Wind Turbines or PV are penalized by their low predictability which makes them inadequate for AS requiring long activation time. EVs also face similar issues.

- Not only DER are technically capable of providing AS, but they also are available, as shown by the quantification of the maximum reserve. The theoretical **potential is significant** (e.g. from 5 to 30 times larger than the reserve needs for FRRa and FRRm) **compared to the reserve needs** and a large amount can be provided by resources connected at the distribution level.
- Although it is difficult to clearly envision the future of **FACTS** for distribution network applications for many reasons (costs, lack of information on their potential), they s**hould be seriously considered by DSOs to improve the management of their network** or even to support the transmission grids.
- The **modelling of the distribution networks** strongly **depends on the data** quality and availability. A methodology which enables the generation of future network scenarios has been developed. In order to deal with the objectives of the simulations and the constraints related to the size of the networks, a **multi-level resolution** is proposed.

7 References

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8 Appendix A: Parametrization tables of DER models

This appendix provides parametrization tables of the DER models in section 2.4 of the deliverable. These tables have been obtained from a broad literature review, but are anyway not meant to be fully exhaustive

8.1 VRES

<table>
<tr><th>Model Parameter</th><th>(Ranges of) value or information and references/comments</th></tr>
<tr><td>Max power production
$\rho[t]$
[kW]</td><td>The max power generation profile can be represented with time series obtained by forecasting methods [29]–[33], or power generation profiles of some representative days, and/or historical data of forecast and real generation.</td></tr>
<tr><td>maximum power generation
u_{gen}^{max}</td><td>From GSE data in Italy [128], max power ranges are (also with some crude statistical distribution across Italy)
• For PV: 1 kW to 10MW
<table>
<tr><th></th><th>2013</th><th></th><th>2014</th><th></th><th>Var % 2014//2013</th><th></th></tr>
<tr><td>Classi di potenza (kW)</td><td>n°</td><td>MW</td><td>n°</td><td>MW</td><td>n°</td><td>MW</td></tr>
<tr><td>1<=P<=3</td><td>193.988</td><td>535,4</td><td>213.157</td><td>586,8</td><td>+9,9</td><td>+9,6</td></tr>
<tr><td>3<P<=20</td><td>343.098</td><td>2.608,7</td><td>374.474</td><td>2.794,0</td><td>+9,1</td><td>+7,1</td></tr>
<tr><td>20<P<=200</td><td>47.756</td><td>3.752,0</td><td>49.158</td><td>3.857,7</td><td>+2,9</td><td>+2,8</td></tr>
<tr><td>200<P<=1.000</td><td>10.396</td><td>7.183,5</td><td>10.503</td><td>7.241,2</td><td>+1,0</td><td>+0,8</td></tr>
<tr><td>1.000<P<=5.000</td><td>934</td><td>2.292,0</td><td>943</td><td>2.315,8</td><td>+1,0</td><td>+1,0</td></tr>
<tr><td>P>5.000</td><td>183</td><td>1.813,8</td><td>183</td><td>1.813,8</td><td>+0,0</td><td>+0,0</td></tr>
<tr><td>Totale</td><td>596.355</td><td>18.185,5</td><td>648.418</td><td>18.609,4</td><td>+8,7</td><td>+2,3</td></tr>
</table>
• Wind turbines (farms): 100 kW to 30 MW
<table>
<tr><th></th><th>2013</th><th></th><th>2014</th><th></th><th>2014 / 2013 Variazione %</th></tr>
<tr><td>Classi di potenza (MW)</td><td>n°</td><td>MW</td><td>n°</td><td>MW</td><td>n°</td></tr>
<tr><td>P ≤ 1 MW</td><td>1.023</td><td>186,6</td><td>1.477</td><td>233,5</td><td>44,4</td></tr>
<tr><td>1 MW < P ≤ 10 MW</td><td>107</td><td>528,1</td><td>108</td><td>536,1</td><td>0,9</td></tr>
<tr><td>P> 10 MW</td><td>256</td><td>7.846,1</td><td>262</td><td>7.933,5</td><td>2,3</td></tr>
<tr><td>Totale</td><td>1.386</td><td>8.560,8</td><td>1.847</td><td>8.703,1</td><td>33,3</td></tr>
</table>
• hydro: 10kW to 50 MW
<table>
<tr><th></th><th>2013</th><th></th><th>2014</th><th></th><th>2014 / 2013 Variazione %</th><th></th></tr>
<tr><td>Classi di potenza (MW)</td><td>n°</td><td>MW</td><td>n°</td><td>MW</td><td>n°</td><td>MW</td></tr>
<tr><td>P ≤ 1 MW</td><td>2.130</td><td>645,2</td><td>2.304</td><td>678,5</td><td>8,2</td><td>5,2</td></tr>
<tr><td>1 MW < P ≤ 10 MW</td><td>817</td><td>2.476,1</td><td>825</td><td>2.493,9</td><td>1,0</td><td>0,7</td></tr>
<tr><td>P > 10 MW</td><td>303</td><td>15.244,6</td><td>303</td><td>15.245,1</td><td>0,0</td><td>0,0</td></tr>
<tr><td>Totale</td><td>3.250</td><td>18.365,9</td><td>3.432</td><td>18.417,5</td><td>5,6</td><td>0,3</td></tr>
</table>
</td></tr>
<tr><td>ramping constraints
$r_{gen}^{min}, r_{gen}^{max}, r_{load}^{min}, r_{load}^{max}$</td><td>From [129], ramping constraints are negligible (<1sec) for all technologies mentioned above, except for PHES (it can be minutes) and CAES (seconds to minutes).</td></tr>
</table>

<table>
<tr><td>reactive power
q_{grid}</td><td>Circular capabilities, or min triangular capability of 0.9 power factor</td></tr>
<tr><td>subsidies</td><td>Country-dependent, can be expected to be very low or removed in 2030. Currently, subsidies depend on the technology. In Italy (see [130])
• PV subsidies are around 300€/MWh (see below)
<table>
<tr><td></td><td colspan="2">A)
Impianti entrati in esercizio in data successiva al 31 dicembre 2010 ed entro il 30 aprile 2011</td><td colspan="2">B)
Impianti entrati in esercizio in data successiva al 30 aprile 2011 ed entro il 31 agosto 2011</td><td colspan="2">C)
Impianti entrati in esercizio in data successiva al 31 agosto 2011 ed entro il 31 dicembre 2011</td></tr>
<tr><td>Intervallo di potenza</td><td>Impianti su edifici</td><td>Altri impianti</td><td>Impianti su edifici</td><td>Altri impianti</td><td>Impianti su edifici</td><td>Altri impianti</td></tr>
<tr><td>[kW]</td><td>[€/kWh]</td><td>[€/kWh]</td><td>[€/kWh]</td><td>[€/kWh]</td><td>[€/kWh]</td><td>[€/kWh]</td></tr>
<tr><td>1≤P≤3</td><td>0,402</td><td>0,362</td><td>0,391</td><td>0,347</td><td>0,380</td><td>0,333</td></tr>
<tr><td>3<P≤20</td><td>0,377</td><td>0,339</td><td>0,360</td><td>0,322</td><td>0,342</td><td>0,304</td></tr>
<tr><td>20<P≤200</td><td>0,358</td><td>0,321</td><td>0,341</td><td>0,309</td><td>0,323</td><td>0,285</td></tr>
<tr><td>200<P≤1000</td><td>0,355</td><td>0,314</td><td>0,335</td><td>0,303</td><td>0,314</td><td>0,266</td></tr>
<tr><td>1000<P ≤5000</td><td>0,351</td><td>0,313</td><td>0,327</td><td>0,289</td><td>0,302</td><td>0,264</td></tr>
<tr><td>P>5000</td><td>0,333</td><td>0,297</td><td>0,311</td><td>0,275</td><td>0,287</td><td>0,251</td></tr>
</table>
• Wind and hydro: around 100€/MWh
• Other type of subsidies is net metering, amount depends on electricity tariff of the prosumer.</td></tr>
<tr><td>variable O&M costs</td><td>Negligible for PV and wind [104], [131], if they do not operate in extreme conditions or do not vary too fast. In the latter case, there is not enough experience.</td></tr>
</table>

Table 23 Model parametrization for main VRES families

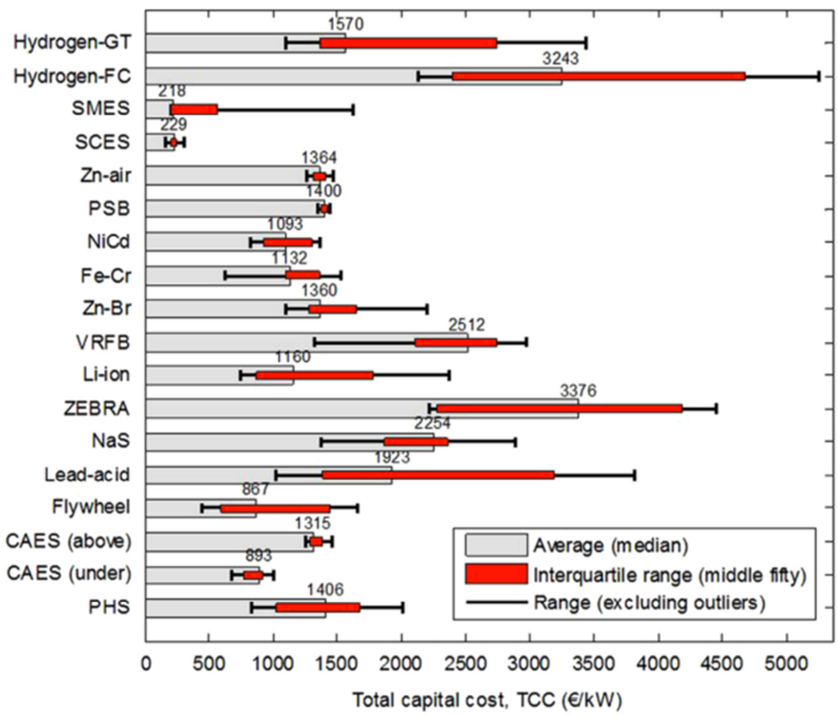
8.2 Stationary storage

One way to compute self-discharge losses v is to express it as $v = (v_{\%,day} \cdot C)/24$ where $v_{\%,day}$ is the average self-discharge percentage of losses compared to the storage capacity.

<table>
<tr><th>Model Parameter</th><th>(Ranges of) value or information and references/comments</th></tr>
<tr><td>storage (battery) capacity
C</td><td>The capacity refers to the total energy that can be stored inside the storage device so the capacity can be estimated as the product of the nominal power u_{gen}^{max}, and the maximum duration of the discharge at this maximal power. Both quantities are provided in [118] by the Department of Energy (DOE), for the current storage installations, for each country and for each main technology.</td></tr>
<tr><td>Self-discharge
$v_{\%,day}$
[% capacity/day]</td><td>From [132]–[134], we have:
• PHES: Small
• CAES: Small
• Flywheels: 100
• Batteries:
    ○ lead-acid: 0.1-0.3
    ○ NaS: 0-20
    ○ Li-ion: 0.1-0.3
    ○ Vanadium redox: small
    ○ zinc bromine: small</td></tr>
<tr><td>minimum state of charge
SoC_{min}</td><td>0% of storage capacity, unless otherwise decided by DER agent</td></tr>
</table>

maximum state of charge SoC_{max}	100% of storage capacity, unless otherwise decided by DER agent

Round-trip efficiency $= \eta_{load} \cdot \eta_{gen}$ [%]	From [132]–[134], we have:
	• PHES: 70 to 85 (median = 78)
	• CAES: 70 to 90
	• Flywheels: 70 to 95 (median = 85)
	• Batteries:
	  ○ lead-acid: 70 to 90 (median = 80)
	  ○ NaS: : 70 to 90 (median = 80)
	  ○ Li-ion: 85-100 (median = 93)
	  ○ Vanadium redox: 60 to 85 (median = 78)
	  ○ zinc bromine: 60 to 80 (median = 70)

minimum power consumption and generation $u_{load}^{min}, u_{gen}^{min}$	u_{gen}^{min} and u_{load}^{min} can be assumed to be 0 kW
maximum power consumption and generation $u_{load}^{max}, u_{gen}^{max}$	u_{gen}^{max} and u_{load}^{max} can be assumed to be equal, and typical values for existing installations can be retrieved in the DOE database [118], for each country and each main storage technology.
ramping constraints $r_{gen}^{min}, r_{gen}^{max}, r_{load}^{min}, r_{load}^{max}$	From [129], ramping constraints are negligible (<1sec) for all technologies mentioned above, except for PHES (it can be minutes) and CAES (seconds to minutes).
reactive power q_{grid}	• PHES: rectangular capability with power factor ranging from 0.85 to 0.95 [135]. • For storage connected to the grid via inverters, a circular capability is provided (usually oversized)
fixed costs	Can be retrieved from the 2015 review from [132]: 

variable O&M costs
[€/MWh]
	Can be retrieved from the 2015 review from [132]:
	• pumped-hydro storage: 0.19 to 0.84
	• CAES: 1.9 to 3
	• flywheels: 0.2 to 3.8
	• batteries:
	  ○ lead-acid: 0.15-0.52
	  ○ NaS: 0.3-5.6
	  ○ Li-ion: 0.4-5.6
	  ○ Vanadium redox: 0.2-2.8
	  ○ zinc bromine: 0.3-2

Table 24 Model parametrization for the stationary storage model

8.3 Mobile storage

Model Parameter	(Ranges of) value or information and references/comments
storage (battery) capacity C	• from 17 to 100 kWh (values from current EVs, extracted from [136]) • average: 30 kWh for family cars, 50 kWh for commuters and taxis [137]
self-discharge v	5% in 24h, then 4-5% per month [138]
minimum state of charge $\boldsymbol{SoC_{min}}$	20% of storage capacity [139] technical value: it is usually higher at some times of the day, depending on the driving need (time series to be computed)
maximum state of charge $\boldsymbol{SoC_{max}}$	100% of storage capacity [139]
grid-to-storage charging efficiency $\boldsymbol{\eta_{load}}$	95% for the battery and 95% for the inverter [140] ==> 90% efficiency
storage-to-grid discharging efficiency $\boldsymbol{\eta_{gen}}$	• 0 if V2G not technically feasible • 95% for the battery and 98% for the inverter [140] ==> 93% efficiency
minimum power consumption and generation $\boldsymbol{u_{load}^{min}, u_{gen}^{min}}$	0 kW
maximum power consumption and generation $\boldsymbol{u_{load}^{max}, u_{gen}^{max}}$	lower range: 3-4 kW [141]–[143] upper range: 120 kW [144] Upper ranges are likely less available (at least not at homes) since grid connection requirements are different.
reactive power $\boldsymbol{q_{grid}}$	half- or semi-circular capability [43]
driving need $\boldsymbol{K_t}$	From [137], we have the following information: **Commuters on the road**: from 7 AM to 9 AM, from 5 PM to 7 PM, average distance=35 km **Family cars on the road**: from 7 AM to 12 PM, 2 PM to 5PM, 7:30 PM to 10:30 PM, average distance=25 km **Taxis on the road**: from 6 AM to 11PM, average distance = 50 km

driving efficiency μ	From [140], we have: URBAN: Small cars: 0.13 kWh/km Middle-class car: 0.177 kWh/km Large cars: 0.203 kWh/km RURAL: Small cars: 0.118 kWh/km Middle-class car: 0.152 kWh/km Large cars: 0.219 kWh/km HIGHWAY: Small cars: 0.216 kWh/km Middle-class car: 0.232 kWh/km Large cars: 0.334 kWh/km
average speed of a trip v_{avg}	From [140], we have: URBAN: 11.42 km/h RURAL: 34.11 km/h HIGHWAY: 104.94 kw/h
discomfort cost $\phi(t)$	difficult to quantify. It could be the cost of using an alternative transportation means, or the cost the user would like to get to cancel a non-essential car travel (in the example in Figure 10A, it is a non-essential travel in the evening). A reasonable range could be from 2 to 100 €/hour
variable O&M costs	0.4-5.6 €/MWh [132]

Table 25 Model parametrization for the EV model

8.4 Conventional generators

Model Parameter	(Ranges of) value or information and references/comments
generator efficiency η_{gen}	from [145] and [45], we have: • combined cycle power plant: from 50 to 60% • gas turbines: 35 to 40% • steam power plants (coal) : 38 to 48% • ICE: up to 45% • nuclear plants: 33% See also the relative efficiency in Figure 12 when the load factor is lower than 100%
maximum power generation u_{gen}^{max}	from [146], we have different categories of conventional generators. Ranges of values for those connected to the transmission grid (or also medium-voltage grid?) are from 50 to 500 MW. From [147], we have ranges of values between 0.3 MW and 70 MW for industrial generators connected to medium voltage network.

minimum power generation $\boldsymbol{u_{gen}^{min}}$	From [146], ranges of values are between 10 and 150 MW. From [45], we have: • combined cycle power plant: 15 to 50 % of of u_{gen}^{max} • coal steam turbines: 20 to 40 % of u_{gen}^{max} • gas turbines: 20 to 50 % of u_{gen}^{max}
reactive power $\boldsymbol{q_{grid}}$	rectangular capability, as indicated in Figure 11, from 0.45 u_{gen}^{max} capacitive to 0.6 u_{gen}^{max} inductive
ramping-up limit $\boldsymbol{r_{gen}^{max}}$	From [45], we have (in % u_{gen}^{max}/min) • gas turbines: 8 to 20 • combined cycle: 2 to 8 • coal steam turbines: 1-6 • ICE: 100 • nuclear plants: 3 to 10
ramping-down limit $\boldsymbol{r_{gen}^{min}}$	Same values than for ramping-up but with negative sign.
ramping limit at start-up and shut-down $\boldsymbol{r_{gen}^{SU}}$	From [146], there are actually no further constraints than classical ramping constraints. From [45], we have: • coal steam turbines: 100% $\boldsymbol{u_{gen}^{max}}$ in 4 to 8 hours • combined cycle: 100% $\boldsymbol{u_{gen}^{max}}$ in 2 to 4 hours • gas turbines: 100% $\boldsymbol{u_{gen}^{max}}$ in <0.1 hour
minimum ON time $\boldsymbol{MO}$	From 1-2 hours to 40 hours [146]
minimum OFF time $\boldsymbol{MS}$	From 1 to 2 hours [146]
fuel costs FC	From [115], we have for 2030 expectations: • coal: 1-3 €/GJ (1.1 for lignite, 2.2 to 3 for hard coal) • gas: 7-10€/GJ
CO2 price $\boldsymbol{\lambda_{CO2}}$	17 to 76€/ton CO2 expected for 2030 [115]
specific CO2 emissions $\boldsymbol{r_{CO2}}$	Between 120 (natural gas) and 230 (coal) Pounds of CO2 emitted per million British thermal units (Btu) [148]
variable O&M costs VOM	3-10 €/MWh [149]

shut-down and start-up costs, SUC and SDC	30 to 4500€ for SUC, quite negligible for SDC [146]

Table 26 Model parametrization for the conventional generators model

8.5 CHP

Model Parameter	(Ranges of) value or information and references/comments
CHP conversion efficiency $\eta_{gen,elec}$ $\eta_{gen,heat}$ $\eta_{gen,total}$	• fuel cells: 20-50% for electricity , 30-80% for heat, 70-100% total [49], [150] • other micro-CHPs: 15% electricity, 80% heat, 96% total [45] • CCGT-CHP (industrial and district heating): 46% electricity, 42% heat, 88% total [45] • gas turbines: 21-40% electricity, 40-70% heat, 80-90% total [150] • diesel and gas reciprocating generators: 30-42% electricity, 38-55% heat, 80-85% total [150]
maximum power generation u_{gen}^{max}	• fuel cells: around 5 kW [49] for micro, from 0.1 to 3 MW for others [150] • diesel and gas reciprocating generators: 30 kW to 6 MW [150] • natural gas turbines: 0.5-40 MW [150] • micro-turbines: 30-400 kW [150]
minimum power generation u_{gen}^{min}	• fuel cells: 0 kW [49] • values in Table 26 could be used
(minimum and maximum) heat demand ξ_{heat}^{min}, ξ_{heat}^{min} or ξ_{heat}	This parameter depends on many factors (CHP type, country, ...): scenarios to be determined for each specific situation by the user of the model.
thermal losses v_{heat}	It depends on the thermal insulation of the storage
capacity of thermal storage C_{heat}	It depends on the type of CHP (industrial vs micro-CHP). For micro-CHP, it could be the size of the water tank for heating water purposes (see section 2.4.6).In [45], they implicitly dimension it by assuming a maximum shifting or the CHP heat generation by 4-12 hours.
reactive power q_{grid}	Reactive power capability depends on the grid coupling technology. In case of rectangular capability, values from Table 26 could be used.
ramping-up and -down limits r_{gen}^{max} and r_{gen}^{min}	When applicable, same values as in Table 26 can be used (ICE, gas turbines, CCGT...) For fuel cells (micro-CHPs), 0.06-0.20 kW/min (1-4 % u_{gen}^{max}/min) [49] general, 5-20 %/min [45]
variable O&M costs *VOM*	From [45], we have: • CCGT CHP: 3 €/MWh • micro-CHP: 20 €/MWh • mini-CHP: 28 €/MWh

fuel costs and CO2 emission costs	See Table 26 for classical fuels, for recycled (renewable) fuels, smaller values can perhaps be used.
discomfort cost	Can be assumed to be 0 if no deviation of heat demand is allowed, otherwise, this depends on each user/application.
subsidies	No subsidies for 2030 is possible, otherwise, values between current and 0 should be chosen (depending on each pilot country).
start-up and shut-down costs, SUC and SDC	SUC: 200 € [151], 1342 € for 32 MW capacity [152], see also Table 26

Table 27 Model parametrization for the CHP model

8.6 TCL

Boiler, first order model	
Model Parameter	(Ranges of) value or information and references/comments
Volume of storage capacity V	150, 200, 300 and 400 l with shares of each category being 10, 25, 25 and 40% [153]
Max temperature of the boiler T_{max}	Between 55 and 65°C (uniform distribution) [153]
conversion efficiency η_{load}	100% [153]
minimum and maximum active power consumption $u_{load}^{min}, u_{load}^{max}$	u_{load}^{min} = 0 and u_{load}^{max} can be uniformly distributed between 3 and 6 kW [153]
(minimum and maximum) heat demand ξ	It depends on many factors (season, country ...): scenarios to be determined for each specific situation by the user of the model. In [153], a methodology is provided to compute and use the probability of water draw throughout the day.
external (air) temperature T_a	It depends where the boiler is located. If it is inside, a 16°C temperature can be assumed (or less if it is located in a colder room). If outside, it would depend on the external air temperature.
reactive power q_{grid}	Equal to 0 (power factor = 1) since it is a pure resistor.
External surface of the buffer A	typically around 1.57 m² [153]

heat loss coefficient of the buffer, $\boldsymbol{\mu_{loss}}$	uniformly distributed from 0.2 to 1 $W/_{m^2} \cdot {}^{\circ}C$ [153]

Table 28 Model parametrization for the boiler model

Heat pump and second order building model	
Model Parameter	(Ranges of) value or information and references/comments
Thermal capacity of the indoor air $\boldsymbol{C_{int}}$	From [55][20], a normal distribution with mean of 11.59 MJ/°C and standard deviation of 1.74 MJ/°C
Thermal capacity of the walls $\boldsymbol{C_{env}}$	From [55], a normal distribution with mean of 25.92 MJ/°C and standard deviation of 3.89 MJ/°C
Thermal conductance between indoor air and walls $\boldsymbol{1/R_{int}}$	From [55], a normal distribution with mean of 4490 W/°C and standard deviation of 674 W/°C
Thermal conductance between walls and outdoor air $\boldsymbol{1/R_{env}}$	From [55], a normal distribution with mean of 332 W/°C and standard deviation of 50 W/°C
Thermal conductance between indoor and outdoor air (ventilation losses) $\boldsymbol{1/R_{ext}}$	A value of 192 W/°C can be considered [22]
heating distribution factor $\boldsymbol{f_{rad}}$	A value of 0.3 can be considered [22]
solar gain factor $\boldsymbol{gA}$	A value of 18.8 m^2 can be used
solar radiation $\boldsymbol{SR}$	Time series depending on location, season, time and weather. This time series should be correlated with the outdoor temperature, $\boldsymbol{T_{ext}}$ (see below)
outdoor temperature $\boldsymbol{T_{ext}}$	Time series depending on the location, season and weather.
internal heat gains $\boldsymbol{Q_{int,gains}}$	Time series representing the heat generated by internal loads and occupants.
Min and max indoor temperatures $\boldsymbol{T_{int}^{min}}, \boldsymbol{T_{int}^{max}}$	Time series depending on house occupancy probability and possible other factors. From [55], a normal distribution of the temperature setpoint with mean of 19°C and standard deviation of 0.5°C can be considered, while a normal distribution of the $T_{int}^{max} - T_{int}^{min}$ interval of mean 1 deg with a standard deviation 0.25°C is assumed.

[20] Note that this ref does not refer to a particular location for the buildings, but [22] have shown that these resistance and capacitances parameters depend on the building type, so they should be adapted in case very different buildings are considered in different regions.

conversion efficiency from electric to thermal power $\eta_{el,thermal}$ (also denoted COP)	From [55], a value of 3 can be considered
minimum and maximum active power consumption $u_{load}^{min}, u_{load}^{max}$	• u_{load}^{min} = 0 • for residential purposes, u_{load}^{max} values of 2 kW [55] and 4.3 kW [56] are reported
reactive power q_{grid}	fixed power factor = 0.99 [154]

Table 29 Model parametrization for the heat pump and second-order building model

TCL discomfort cost

Similarly as with defining the value of lost load, it is very difficult to define the range of deviations from normal operation that are acceptable for the end user, and the accompanying discomfort costs, **[155]–[157]**. These costs are hard to define as they depend on a large number of factors, such as the time of the day, occupancy of the building, duration of discomfort, size of temperature deviation, air humidity, etc. Nevertheless, the most challenging factor is the subjective nature of thermal comfort sensation.

Traditionally, thermal comfort is defined by the two measures presented in **[156]**, which formed the basis for definition of ISO thermal comfort standard. These measures are percentage mean vote (PMV) and predicted percentage dissatisfied (PPD), and form the basis for the comfort constraints in majority of literature, although there is an ongoing discussion on how to improve them.

The trade-offs between the energy costs and thermal comfort are analysed in **[157]**. Therein, it is shown that avoiding the use of detailed thermal comfort models overestimates flexibility potential and leads to poor comfort conditions. Therein, a strategy that approximates the comfort region described by Fanger's thermal comfort model using linear constraints.

There are two approaches for including the thermal comfort into the problem formulation: it can be either added to the cost function, or included as a constraint of the optimization problem. Mathematically, there is no significant difference between the two, as according to the Lagrangian relaxation, constraints can be added to the cost function.

Given the difficulties with determining the thermal comfort and its economic value, it is understandable that in the majority of literature, the flexibility from TCLs is modelled as hard constraints of preserving thermal user comfort. In this line, the discomfort costs are defined to be 0. If however, it is still preferable to relax these constraint and assign the costs to this deviation, the following approaches were found in literature.

If the thermal comfort is modelled as a part of objective function, possibly to make sure that the problem is always feasible, this term can be weighted by a factor that highly penalizes the deviation of the controlled variable (temperature and/or humidity) from the defined domain. For instance, in **[158]**, instead of the discomfort cost, such an 'infeasibility cost' is defined for cases when it is not possible to serve the heat needs, which in fact define a given temperature band. The value of this penalty factor is defined to be 134.2 €/MWh, however, there is no physical interpretation for this value.

In some papers, the discomfort costs are defined for a deviation from certain temperature setpoint. For instance in **[159]**, deviation from the set-point temperature (there is no temperature band, so no dead-band around the setpoint) is penalized with discomfort weights defined hour by hour, expressed as DKK/degree. These costs are defined to be in range 0.1 - 0.2 $\boldsymbol{DKK}/(°\boldsymbol{C} \cdot \boldsymbol{hour})$. This can be extended so that only deviation from a certain predefined temperature band is penalized. The penalization can be defined as linearly dependent on the distance from the defined temperature band.

In **[160]**, the following modification of PPDs is proposed to be used as comfort constraint. *"The cost function must be an expression of the trade-off between comfort and energy consumption. The chosen indicator of thermal comfort is Fanger's PPD (Fanger, 1972), while energy cost is considered to be proportional to the boiler energy consumption (Qb). In the discomfort cost, PPD is computed with default parameters for nonmeasured aspects (air velocity, humidity and metabolic activity). Furthermore, it is assumed that occupants can adapt their clothing to the zone temperature. This method allows modelling a comfort range in which occupants are satisfied. With the chosen value for parameters, the comfort zone covers operative temperatures from 21C to 24C. PPD is also shifted down by 5%, to give a minimum value of 0. This modified PPD index will be referred to as PPD".* Discomfort cost is represented in Fig 3.

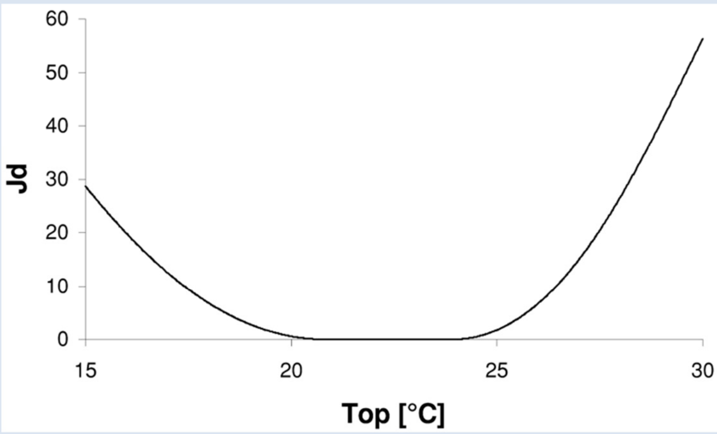


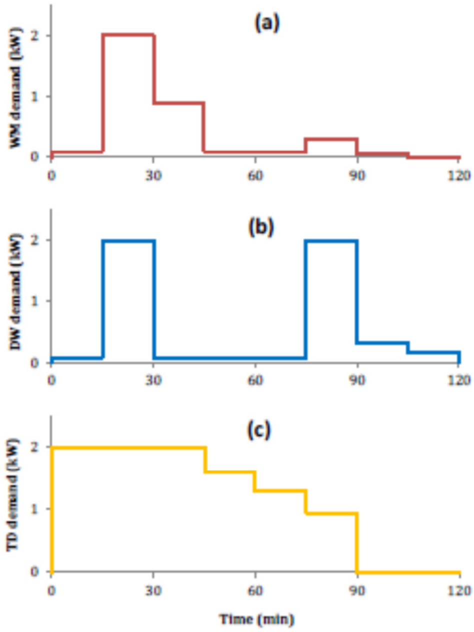
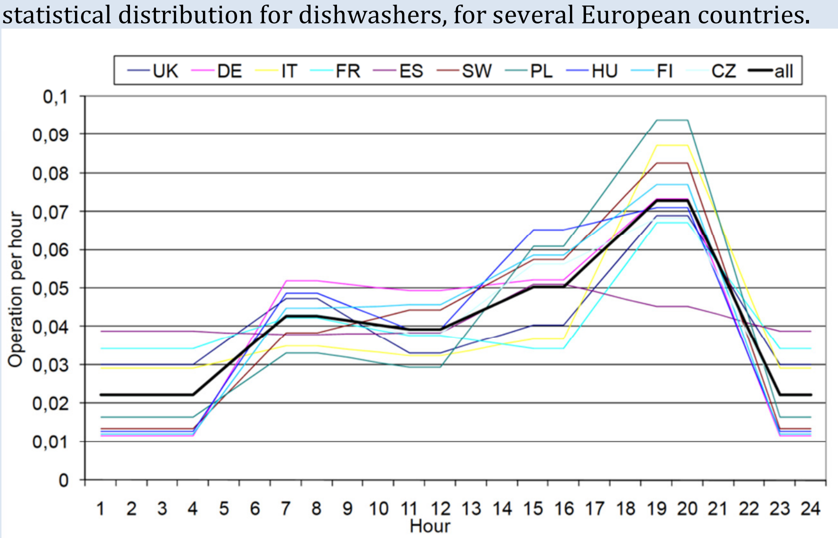
Figure 33 *Discomfort cost, taken from* ***[160]****, based on the modified PPD index*

In **[155]**, comfort costs are defined by a misery function that is dependent on temperature and occupancy ('occupant comfort cost model'). Correction factors and average hourly salary are used to transform the loss of comfort into money.

Table 30 Zoom on TCL discomfort cost

8.7 Load shifting

Wet appliances

Model Parameter	(Ranges of) value or information and references/comments
Wet appliance load profile $u_{load}^{profile}(t)$ (also allows to determine $\Delta T_{load,profile}$)	Note that $\Delta T_{load,profile}$ can directly be computed, once knowing the load profile (since it is defined as the time length of the load profile). From [161], the representative load profiles for three wet appliances are available: (a) washing machine (WM), (b) dishwasher (DW) and (c) tumble dryer (TD) . 
Baseline starting time of wet appliances $t_{start}^{baseline}$	This can be inferred from a statistical distribution of starting time of wet appliances. Also, if an additional assumption is made that people do not delay already their machine, then $t_{init} = t_{start}^{baseline}$ (otherwise, reasonable assumptions can be made). In the Smart-A project [161], such statistical distribution have been assessed for different wet appliances. As an example, the below figure (from [161]) shows this statistical distribution for dishwashers, for several European countries. 
t_{end}	This can be inferred from the willingness to postpone start distribution [60], and

	assuming t_{init} is known. The average are • washing machines: 5.8 hours • tumble dryers: 5.6 hours • dishwashers: 5?6 hours The discrete statistical distributions for the can be found in [60], to get an idea of the standard deviation that can be applied on the average numbers.
discomfort cost $\lambda_{discomfort}^{shifting}$	• 0 if equation (52) is satisfied • otherwise, very user-dependent. One way to estimate this cost is to use the hourly labour cost in Europe (25 €/hour).
minimum and maximum active power consumption $\boldsymbol{u}_{load}^{min}, \boldsymbol{u}_{load}^{max}$	$\boldsymbol{u}_{load}^{min}$ = 0 and $\boldsymbol{u}_{load}^{max}$ = 2kW (see first row of this table, on wet appliance load profile).
reactive power $\boldsymbol{q}_{grid}$	fixed power factor. According to [64], power factors are in this range: • washing machines: 0.55-0.59 • dishwashers: 0.62-0.65 • tumble dryers: 1 during heating phase, 0.44-0.47 during rotating phase

Table 31 Model parametrization for load shifting of wet appliances

Industrial processes	
Model Parameter	(Ranges of) value or information and references/comments
minimum and maximum active power consumption $\boldsymbol{u}_{load}^{min}, \boldsymbol{u}_{load}^{max}$	Using the survey and methodology described in [59], $\boldsymbol{u}_{load}^{min}$ and $\boldsymbol{u}_{load}^{max}$ can be computed for different process industries, at a global level (country, or European level) and then further assumptions are needed to share it across different sites. For $\boldsymbol{u}_{load}^{min}$, values typically range between 0 and 75 % of $\boldsymbol{u}_{load}^{max}$, depending on the energy-intensive industry [59].
max time of shifting, i.e. difference between $\boldsymbol{t}_{end}$ and $\boldsymbol{t}_{init}$	From [59], shifting max delay goes from a few hours up to 24 hours for the industrial processes, depending on the industry (it of course depends on the capacity utilization level: if a plant operates at full capacity, only load curtailment is possible since there is no flexibility to delay the operation).
Energy constraints from grid to be consumed between $\boldsymbol{t}_{end}$ and $\boldsymbol{t}_{end}$ $\boldsymbol{E}_{min}$ and $\boldsymbol{E}_{max}$	Some insights can be retrieved from [59], where the specific consumption of electricity per ton of product is specified for each industry.
Baseline Load power profile (i.e. when no flexibility is provided)	It depends on each industry: one can reasonably assume that for 2030, the baseline is optimized with respect to day-ahead prices, or some simpler rules indirectly linked to day-ahead prices (avoid consuming at peak hours, consume more at night and/or w-e). In [162], typical (aggregated) power profiles are specified for different industries (and different load factors), as for example, the following load curve.

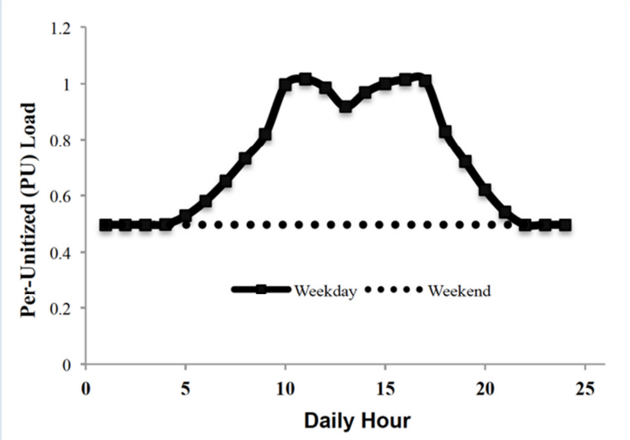
	
reactive power q_{grid}	Industrial loads are usually using power factor correction to get a power factor closer to 1 [62], [63], at least larger than 0.90 (since they usually are financially penalized for a lower power factor).
Flexibility cost components	Very dependent on each process industry: • manpower cost: see Table 31 • maintenance costs • fuel costs: e.g. see Table 26 • storage or delayed production costs

Table 32 Model parametrization for load shifting of industrial processes

8.8 Load curtailment

Model Parameter	(Ranges of) value or information and references/comments
minimum and maximum active power consumption $u_{load}^{min}, u_{load}^{max}$	• see Table 32 for industrial processes • For lighting, it can easily be found by assuming lightning rated power and number of lights.
reactive power q_{grid}	similar to reactive power capabilities described in Table 31 and Table 32
Baseline power profile	It depends very much on the type of load being shed. • For lights, it can be assumed to be equal to u_{load}^{max} and a time series on the probability of lighting being on should be used. • For industrial processes, it can also be assumed in most cases that the baseline power profile is close or equal to u_{load}^{max}, or has been optimized with respect to day-ahead market prices in case of the process is not running at full-capacity. This baseline can depend on many factors: time, season, weather, market situation of an industry sector,...
interruption costs	According to [66], such data have been estimated in Nordic countries, Belgium and Germany. Interruption costs for Finland may be found in [66], [163] and are typically in the range between 3000 and 100 000 €/MWh, and can reasonably be used for other European countries as well. Unit cost for load shedding (€/kWh) is typically decreasing with interruption duration, or in other words, for a given power, the total cost increase, but not linearly with time (less fast), which is relevant since we do not consider loads

	with storage capabilities (like for load shifting or TCLs).

Table 33 Model parametrization for load curtailment

9 Appendix B: Consultation for advanced power technologies

Table 34: Consultation network operators: ' Is it a promising technology?'

Is it a promising technology?					
Device	**Partner 1**	**Partner 2**	**Partner 3**	**Partner 4**	**Partner 5**
SVC (Static VAR Compensators)	Yes. Locally it improves the power factor the voltage profile. In the primary substation it can correct the global power factor.	Yes, it is nowadays already used in the transmission grids in different European countries.	Yes, for fast dynamic voltage/reactive power regulation.		Advantage in the immediate response to voltage changes. It is expensive, but suitable for the resolution of rapid transients.
D-STATCOM	Yes. Locally it improves the power factor the voltage profile. In the primary substation it can correct the global power factor.	Yes, due to its features it can be very useful for the management of current and future distributions grids.	Yes, for fast dynamic voltage/reactive power regulation.		A promising technology to supply the reactive power to maintain the power quality, also with non-linear loads.
Synchronous Condensers	Yes. Locally it improves the power factor the voltage profile. In the primary substation it can correct the global power factor.	Yes, it is nowadays already used in the transmission grids in different European countries.	Yes at transmission level due to added reactive current/inertia capability. No application for distribution networks.		Useful to supply the reactive power and to contribute to the total inertia of the network.
Power Electronic Transformers	No. It is a very flexible device but its cost is too high with respect the benefits. It can be used for sensitive applications.		Yes because it can be more compact (compared to standard transformer) and provide additional fast voltage regulation.		It is a promising technology concerning the ability to maintain constant the output voltage during load fluctuations.
On Load Tap Changers MV/LV	Yes. It allows to decouple the LV network with respect the		No because it is not able to provide dynamic voltage	No, it is currently too	It is useful in the presence of high

	MV network, enlarging the voltage limits in the MV. It doesn't necessary need complex controls.		regulation.	expensive.	amounts of distributed generation on the low voltage network.
Medium voltage(multi-terminal) DC network			Yes. It increases the maximum loading of distribution networks without increasing fault current level. It also provides voltage controllability to allow DERs connection.		
IPC Interphase Power Controller	No. It is not needed in the distribution network.		It is difficult to say. The cost is higher than other technologies of phase balancing but it does provide additional controllability.		It is not useful for the provision of ancillary services.
Real time spectrum analyser	Yes. In specific locations it can help to analyse the network, identify the source of the problem and so to improve the power quality			Yes, it is useful to know DERS' production.	
UP with current and voltage measurement	Yes. It allows a better state estimation for a better control of the network.			Yes it is useful to know feeders' load.	Essential for the dynamic data acquisition (measures as input of the regulation algorithms).
STS Static Transfer Switch	Yes. But it will have a limited impact since it can be used only in certain conditions.		No it is not able to provide dynamic voltage regulation.		Not useful for the provision of ancillary services.
DVR (Dynamic voltage restorer)	Yes. For particular users where the high power quality is a necessity or to improve the capacity of the generators to	Yes (due to its features it can be very useful for the management of current and future distributions grids).	No, the high cost and the power losses limits its application to specific load requirement.		Not useful for the provision of ancillary services.

	overcome the faults.				

Table 35: General comments from network operators about the advanced power technologies

Other general comments		
Device	**Partner 1**	**Partner 3**
SVC - Static VAR compensators	SVC, D-STATCOM and Synchronous condenser are partially in competition and they have different advantage depending on the types of services.	Harmonic issues have to be considered. At distribution voltage level, D-STATCOM is preferred to SVC.
D-STATCOM	SVC, D-STATCOM and Synchronous condenser are partially in competition and they have different advantage depending on the types of services.	At distribution voltage level, D-STATCOM is preferred to SVC due to its compact design, faster dynamics, and better voltage/current waveform quality.
Synchronous Condensers	SVC, D-STATCOM and Synchronous condenser are partially in competition and they have different advantage depending on the types of services.	Compared to STATCOM, it can provide high fault current and is more robust during transient conditions. The operating cost (e.g. power losses) would be higher than STATCOM.
Power Electronic Transformers		Losses, costs, and reliability need further improvement. Limited fault current may not be compatible with current protection arrangement.
On Load Tap Changers MV/LV		Not for LV network.
MVDC - Medium Voltage (multi-terminal) DC Network		Other DC sources/loads (e.g. PV, EV charging) can also be connected to the DC side to form multi-terminal system.
IPC - Interphase Power Controller		Not aware of any practical use.
STS - Static Transfer Switch		Also affect the fault current level.

DVR - Dynamic voltage restorer		There has been very limited use of DVR in real systems.

10 Appendix C: Detailed tables for Qualitative and Quantitative mapping exercise

10.1 Qualitative mapping

Table 36: Qualitative mapping of flexibility resources capability in provisioning ancillary needs in current situation (2015/2016)

		Intermittent DG (VRES)			Stationary Storage								Mobile Storage (EV)		CHP		TCL	Load shifting	Load shedding	Industrial Process
		Wind		PV	Pumped Hydro		CAES		Flywheel		Batteries									
Ancillary services for frequency control	Primary frequency control (FCR)	Inv	2						Inv	4	Inv	4	Inv	2	Inv	2				
		SG	3		SG	3	SG	4	SG	4					SG	3				
		DFIG	3		DFIG	4														
		IG	3	2			IG	4	IG	4					IG	3	2	0	3	2
	Secondary power-frequency control (aFRR)	Inv	2						Inv	1	Inv	4	Inv	2	Inv	3				
		SG	2		SG	3	SG	4	SG	1					SG	4				
		DFIG	2		DFIG	4														
		IG	2	2			IG	4	IG	1					IG	4	4	2	2	3
	Tertiary control (mFRR)	Inv	2						Inv	0	Inv	4	Inv	2	Inv	3				
		SG	2		SG	3	SG	4	SG	0					SG	4				
		DFIG	2		DFIG	4														
		IG	2	2			IG	4	IG	0					IG	4	3	3	1	4
Voltage control services	Primary voltage control	Inv	3						Inv	4	Inv	4	Inv	3	Inv	2				
		SG	3		SG	4	SG	3	SG	3					SG	1				
		DFIG	3		DFIG	4														
		IG	0	2			IG	0	IG	0					IG	1	0	0	1	0
	Secondary voltage control	Inv	3						Inv	0	Inv	4	Inv	3	Inv	3				
		SG	2		SG	4	SG	4	SG	0					SG	2				
		DFIG	3		DFIG	4														
		IG	0	2			IG	0	IG	0					IG	1	0	0	1	0
	Tertiary voltage control	Inv	3						Inv	0	Inv	4	Inv	3	Inv	3				
		SG	2		SG	4	SG	4	SG	0					SG	2				
		DFIG	3		DFIG	4														
		IG	0	2			IG	0	IG	0					IG	1	0	0	0	0
Others ancillary services	Interruptible load service (Italy, Spain, Belgium)	Inv	0			NA		NA	Inv	NA	Inv	NA	Inv		Inv	4				
		SG	0		SG	NA	SG	NA	SG	NA		NA			SG	4				
		DFIG	0		DFIG	NA		NA		NA		NA								
		IG	0	0		NA	IG	NA	IG	NA		NA			IG	4	3	0	3	4
	Black start (Belgium, Spain)	Inv	3						Inv	0	Inv	4	Inv		Inv	4				
		SG	3		SG	4	SG	4	SG	0					SG	4				
		DFIG	3		DFIG	4									DFIG					
		IG	0	3			IG	0	IG	0					IG	4	0	0	2	0
	Grid losses compensation (Austria, Belgium)	Inv	3						Inv	3	Inv	3	Inv		Inv	4				
		SG	3		SG	3	SG	3	SG	3					SG	4				
		DFIG	3		DFIG															
		IG	2	3		1	IG	1	IG	1					IG	4	2	2	2	3
	Strategic reserve (Belgium)/Peak load capacity reserve (Finland)	Inv	2						Inv	3	Inv	3	Inv		Inv	3				
		SG	2		SG	3	SG	0	SG	3					SG	3				
		DFIG	2		DFIG															
		IG	2	2		3	IG	3	IG	3					IG	3	1	1	2	4
	Technical restriction resolution (Spain)	Inv	2						Inv		Inv		Inv		Inv					
		SG	2		SG	3	SG	3	SG						SG					
		DFIG	2		DFIG															
		IG	2	2		3	IG	3	IG						IG		1	0	2	0

Table 37: Qualitative mapping of flexibility resources capability in provisioning ancillary needs in future situation (2030)

		Intermittent DG (VRES)			Stationary Storage								Mobile Storage (EV)		CHP					
		Wind		PV	Pumped Hydro		CAES		Flywheel		Batteries						TCL	Load shifting	Load curtailment	Industrial Process
Ancillary services for frequency control	Fast Frequency Reserve (FFR): Inertia Emulation	Inv	1						Inv	3	Inv	4	Inv	3	Inv	2				
		SG	4		SG	3	SG	4	SG	3					SG	3				
		DFIG	3		DFI	3														
		IG	4	2			IG	4	IG	3					IG	2	1	0	2	3
	Frequency Containment Reserve (FCR)	Inv	3						Inv	4	Inv	4	Inv	3	Inv	2				
		SG	3		SG	3	SG	4	SG	4					SG	3				
		DFIG	3		DFI	3														
		IG	3	3			IG	4	IG	4					IG	3	3	0	3	3
	Frequency Restoration Reserve (FRR)	Inv	3						Inv	1	Inv	4	Inv	3	Inv	3				
		SG	3		SG	3	SG	4	SG	1					SG	4				
		DFIG	3		DFI	4														
		IG	3	3			IG	4	IG	1					IG	4	4	2	3	4
	Replacement Reserve (RR)	Inv	2						Inv	0	Inv	4	Inv	2	Inv	3				
		SG	2		SG	4	SG	4	SG	0					SG	4				
		DFIG	2		DFI	4														
		IG	2	2			IG	4	IG	0					IG	4	2	2	1	4
	Ramp Margin (RM): Ramp Control	Inv	3						Inv	4	Inv	4	Inv	2	Inv	1				
		SG	2		SG	4	SG	3	SG	4					SG	1				
		DFIG	3		DFI	4														
		IG	2	2			IG	3	IG	4					IG	1	2	1	2	3
Ancillary services for voltage control	Fault ride-through capability	Inv	4						Inv	4	Inv	4	Inv	4	Inv	4				
		SG	4		SG	NA	SG	NA	SG	4					SG	4				
		DFIG	4		DFI	NA														
		IG	1	4			IG	NA	IG	1					IG	1	0	0	1	0
	Congestion management_Voltage control	Inv	4						Inv	4	Inv	4	Inv	4	Inv	4				
		SG	3		SG	4	SG	3	SG	3					SG	2				
		DFIG	3		DFI	4														
		IG	0	4			IG	0	IG	0					IG	1	1	0	1	0
	Primary voltage control	Inv	3						Inv	4	Inv	4	Inv	3	Inv	3				
		SG	3		SG	4	SG	3	SG	3					SG	1				
		DFIG	3		DFIG	4														
		IG	0	3			IG	0	IG	0					IG	1	1	0	1	0
	Secondary voltage control	Inv	3						Inv	0	Inv	4	Inv	3	Inv	4				
		SG	2		SG	4	SG	4	SG	0					SG	2				
		DFIG	3		DFI	4														
		IG	0	3			IG	0	IG	0					IG	1	1	0	1	0
	Tertiary voltage control	Inv	3						Inv	0	Inv	4	Inv	3	Inv	4				
		SG	2		SG	3	SG	4	SG	0					SG	2				
		DFIG	3		DFI	3														
		IG	0	3			IG	0	IG	0					IG	1	0	0	0	0
Ancillary services for power quality improvement	Injection of negative sequence voltages	Inv	3						Inv	3	Inv		Inv	4	Inv	3				
		SG	0		SG	0	SG	0	SG	0					SG	1				
		DFIG	3		DFI	0														
		IG	0	3			IG	0	IG	0					IG	1	0	0	2	0
	Damping of low order harmonics	Inv	3						Inv	3	Inv	3	Inv	4	Inv	3				
		SG	0		SG	0	SG	0	SG	0					SG	3				
		DFIG	3		DFI	0														
		IG	0	3			IG	0	IG	0					IG	3	0	0	2	0
	Mitigation of flicker	Inv	3						Inv	4	Inv	2	Inv	4	Inv	3				
		SG	3		SG	0	SG	0	SG	4					SG	1				
		DFIG	3		DFI	0														
		IG	0	3			IG	0	IG	1					IG	1	0	0	2	1
	Damping of power system oscillations	Inv	3						Inv	2	Inv	2	Inv	1	Inv	3				
		SG	4		SG	4	SG	4	SG	2					SG	1				
		DFIG	3		DFI	4														
		IG	1	3			IG	4	IG	2					IG	1	0	0	1	0
Others ancillary services (for other purposes or for combined f/V control)	Black start capability	Inv	3						Inv	0	Inv	4	Inv	0	Inv	4				
		SG	3		SG	4	SG	4	SG	0					SG	4				
		DFIG	3		DFI	4														
		IG	0	3			IG	0	IG	0					IG	4	0	0	2	4
	Reduction of power losses	Inv	2						Inv	2	Inv	2	Inv	2	Inv	3				
		SG	1		SG	2	SG	2	SG	2					SG	1				
		DFIG	2		DFI	2														
		IG	1	2			IG	1	IG	1					IG	1	0	2	2	3
	Power factor control	Inv	3						Inv	4	Inv	4	Inv	4	Inv	4				
		SG	3		SG	4	SG	4	SG	4					SG	2				
		DFIG	2		DFI	4														
		IG	0	3			IG	0	IG	0					IG	2	0	0	2	0

10.2 Quantitative mapping

Table 38: Quantitative mapping of flexibility resources availability to current ancillary service needs (Connected to distribution network)

Data Source	
Vision 3-ENTSO-E	(green)
Vision 4-ENTSO-E (TYNDP2014)	(red)
EU Reference scenario	(pink)
DOE Global Energy	(blue)
Others	(yellow)

Technology	Unit	Country	Total	DS	TS
Wind	MW*	DK1	1 234	853	381
Wind	MW*	IT	1 701	499	1 202
Wind	MW*	ES	5 898	3 813	2 085
PV	MW*	DK1	74	74	0
PV	MW*	IT	2 546	2 380	166
PV	MW*	ES	733	724	9
Stationary Storage – Pumped Hydro (DOE)	MW	DK1	0	0	0
Stationary Storage – Pumped Hydro (DOE)	MW	IT	7 287	817	6 470
Stationary Storage – Pumped Hydro (DOE)	MW	ES	2 365	11	2 354
Stationary Storage – Flywheel	MW	DK1	0	0	0
Stationary Storage – Flywheel	MW	IT	0	0	0
Stationary Storage – Flywheel	MW	ES	1	1	0
Stationary Storage – Batteries	MW	DK1	0	0	0
Stationary Storage – Batteries	MW	IT	55	7	47
Stationary Storage – Batteries	MW	ES	2	2	0
Mobile Storage	MW	DK1	57	57	0
Mobile Storage	MW	IT	0	0	0
Mobile Storage	MW	ES	66	66	0
CHP	MW	DK1	3 845	1 825	2 020
CHP	MW	IT	17 861	4 841	13 020
CHP	MW	ES	6 195	3 379	2 816
TCL	MW*	DK1	57	46	12
TCL	MW*	IT	652	652	0
TCL	MW*	ES	772	772	0

				Wind		PV		Stationary Storage: Pumped Hydro (DOE)		Stationary Storage: Flywheel		Stationary Storage: Batteries		Mobile Storage		CHP		TCL	
			AS need in MW (2030)	Available Flexibility (MW*)		Available Flexibility (MW*)		Available Flexibility (MW)		(MW)		(MW)		(MW)		Available Flexibility (MW)		Available Flexibility (MW*)	
		Country		From DS	From TS	From DS	From TS	From DS	From TS	From DS	From TS	From DS	From TS	From DS	From TS	From DS	From TS	From DS	From TS
Ancillary services for frequency control	Frequency Containment Reserve (FCR)	DK		639	286	37	0	0	0	0	0	0	0	3	0	1 232	1 364	1	0
		IT		374	902	1 190	83	613	4 853	0	0	7	47	0	0	3 268	8 789	16	0
		ES		2 860	1 564	362	5	8	1 766	1	0	2	0	3	0	2 281	1 901	19	0
		Weight	FLEX%	3	100 %	2	100 %	3	100 %	4	100 %	4	100 %	2	10 %	3	90 %	2	5 %
	Frequency Restoration Reserve: Automatic (aFRR) :Downwards	DK	257	426	191	37	0	0	0	0	0	0	0	3	0	1 643	1 818	2	1
		IT	1 414	249	601	1 190	83	817	6 470	0	0	7	47	0	0	4 357	11 718	33	0
		ES	669	1 906	1 042	362	5	11	2 354	0	0	2	0	3	0	3 041	2 534	39	0
		Weight	FLEX%	2	100 %	2	100 %	4	100 %	1	100 %	4	100 %	2	10 %	4	90 %	4	5 %
	Frequency Restoration Reserve: Automatic (aFRR) : Upwards	DK	262	426	191	37	0	0	0	0	0	0	0	3	0	1 643	1 818	2	1
		IT	1 471	249	601	1 190	83	817	6 470	0	0	7	47	0	0	4 357	11 718	33	0
		ES	783	1 906	1 042	362	5	11	2 354	0	0	2	0	3	0	3 041	2 534	39	0
		Weight	FLEX%	2	100 %	2	100 %	4	100 %	1	100 %	4	100 %	2	10 %	4	90 %	4	5 %
	Frequency Restoration Reserve: Manual (mFRR) :Downwards	DK	334	426	191	37	0	0	0	0	0	0	0	3	0	1 643	1 818	2	0
		IT	1 028	249	601	1 190	83	817	6 470	0	0	7	47	0	0	4 357	11 718	24	0
		ES	5 473	1 906	1 042	362	5	11	2 354	0	0	2	0	3	0	3 041	2 534	29	0
		Weight	FLEX%	2	100 %	2	100 %	4	100 %	0	100 %	4	100 %	2	10 %	4	90 %	3	5 %
	Frequency Restoration Reserve: Manual (mFRR) : Upwards	DK	426	426	191	37	0	0	0	0	0	0	0	3	0	1 643	1 818	2	0
		IT	1 523	249	601	1 190	83	817	6 470	0	0	7	47	0	0	4 357	11 718	24	0
		ES	3 191	1 906	1 042	362	5	11	2 354	0	0	2	0	3	0	3 041	2 534	29	0
		Weight	FLEX%	2	100 %	2	100 %	4	100 %	0	100 %	4	100 %	2	10 %	4	90 %	3	5 %
Ancillary services for voltage control	Primary voltage control	DK		639	286	37	0	0	0	0	0	0	0	4	0	821	909	0	0
		IT		374	902	1 190	83	613	4 853	0	0	7	47	0	0	2 178	5 859	0	0
		ES		2 860	1 564	362	5	8	1 766	1	0	2	0	5	0	1 521	1 267	0	0
		Weight	FLEX%	3	100 %	2	100 %	3	100 %	4	100 %	4	100 %	3	10 %	2	90 %	0	5 %
	Secondary voltage control	DK		639	286	37	0	0	0	0	0	0	0	4	0	821	909	0	0
		IT		374	902	1 190	83	613	4 853	0	0	7	47	0	0	2 178	5 859	0	0
		ES		2 860	1 564	362	5	8	1 766	0	0	2	0	5	0	1 521	1 267	0	0
		Weight	FLEX%	3	100 %	2	100 %	3	100 %	0	100 %	4	100 %	3	10 %	2	90 %	0	5 %
	Tertiary voltage control	DK		639	286	37	0	0	0	0	0	0	0	4	0	821	909	0	0
		IT		374	902	1 190	83	613	4 853	0	0	7	47	0	0	2 178	5 859	0	0
		ES		2 860	1 564	362	5	8	1 766	0	0	2	0	5	0	1 521	1 267	0	0
		Weight	FLEX%	3	100 %	2	100 %	3	100 %	0	100 %	4	100 %	3	10 %	2	90 %	0	5 %

MW refers to the convesrsion of yearly genereated energy or load in GWh/year by dividing it by 8760*

Table 39: Quantitative mapping of flexibility resources availability to Future ancillary needs (Connected to distribution network)

Data Source		Wind				PV				Stationary Storage: Pumped Hydro (DOE)				Stationary Storage: Flywheel				Stationary Storage: Batteries				Mobile Storage				CHP				TCL				Load shifting				Load shedding				Industrial process			
Vision 3-ENTSO-E		MW*	Total	DS	TS	MW*	Total	DS	TS	MW	Total	DS	TS	MW	Total	DS	TS	MW	Total	DS	TS	MW	Total	DS	TS	MW	Total	DS	TS	MW*	Total	DS	TS	MW*	Total	DS	TS	MW*	Total	DS	TS	MW*	Total	DS	TS
Vision 4-ENTSO-E (TYNDP2014)																																													
EU Reference sce0rio 2016		DK	3291	853	2438	DK	267	267	0	DK	0	0	0	DK	0	0	0	DK	0	0	0	DK1	6000	6000	0	DK1	1815	990	825	DK1	378	306	72	DK1	228	228	0	DK1	0	0	0	DK1	119	119	0
DOE Global Energy Storage		IT	4303	1261	3041	IT	7034	6945	89	IT	7287	817	6470	IT	0	0	0	IT	142	19	123	IT	285	285	0	IT	17861	4841	13020	IT	652	652	0	IT	49	49	0	IT	394	394	0	IT	685	548	137
Others		ES	8224	5317	2907	ES	5521	5451	70	ES	2365	11	2354	ES	1	1	0	ES	4	4	0	ES	2	2	0	ES	6819	3720	3100	ES	772	772	0	ES	37	37	0	ES	NA	NA	NA	ES	358	287	72

		Country	AS need in MW (2030)	Wind: Available Flexibility (MW*) From DS	Wind: From TS	PV: Available Flexibility (MW*) From DS	PV: From TS	Pumped Hydro: Available Flexibility (MW) From DS	Pumped Hydro: From TS	Flywheel: Available Flexibility (MW) From DS	Flywheel: From TS	Batteries: Available Flexibility (MW) From DS	Batteries: From TS	Mobile Storage: Available Flexibility (MW) From DS	Mobile Storage: From TS	CHP: Available Flexibility (MW) From DS	CHP: From TS	TCL: Available Flexibility (MW*) From DS	TCL: From TS	Load shifting: Available Flexibility (MW*) From DS	Load shifting: From TS	Load shedding: Available Flexibility (MW*) From DS	Load shedding: From TS	Industrial process: Available Flexibility (MW*) From DS	Industrial process: From TS
Ancillary services for frequency control	Frequency Containment Reserve (FCR)	DK		640	1 829	200	0	0	0	0	0	0	0	450	0	668	557	119	28	0	0	0	0	50	0
		IT		946	2 281	5 209	66	613	4 853	0	0	19	123	21	0	3 268	8 789	254	0	0	0	295	0	230	58
		ES		3 988	2 180	4 088	52	8	1 766	1	0	4	0	0	0	2 511	2 092	301	0	0	0	NA	NA	120	30
		Weights	FLEX%	3	100 %	3	100 %	3	100 %	4	100 %	4	100 %	3	10 %	3	90 %	3	52 %	0	100 %	3	100 %	3	56 %
	Frequency Restoration Reserve: Automatic (aFRR) :Downwards	DK	257	640	1 829	200	0	0	0	0	0	0	0	450	0	891	743	159	37	59	0	0	0	67	0
		IT	1 414	946	2 281	5 209	66	817	6 470	0	0	19	123	21	0	4 357	11 718	339	0	13	0	295	0	307	77
		ES	669	3 988	2 180	4 088	52	11	2 354	0	0	4	0	0	0	3 348	2 790	402	0	10	0	NA	NA	160	40
		Weights	FLEX%	3	100 %	3	100 %	4	100 %	1	100 %	4	100 %	3	10 %	4	90 %	4	52 %	2	100 %	3	100 %	4	56 %
	Frequency Restoration Reserve: Automatic (aFRR) : Upwards	DK	262	640	1 829	200	0	0	0	0	0	0	0	450	0	891	743	159	37	59	0	0	0	67	0
		IT	1 471	946	2 281	5 209	66	817	6 470	0	0	19	123	21	0	4 357	11 718	339	0	13	0	295	0	307	77
		ES	783	3 988	2 180	4 088	52	11	2 354	0	0	4	0	0	0	3 348	2 790	402	0	10	0	NA	NA	160	40
		Weights	FLEX%	3	100 %	3	100 %	4	100 %	1	100 %	4	100 %	3	10 %	4	90 %	4	52 %	2	100 %	3	100 %	4	56 %
	Frequency Restoration Reserve: Manual (mFRR) :Downwards	DK	334	427	1 219	133	0	0	0	0	0	0	0	300	0	891	743	80	19	59	0	0	0	67	0
		IT	1 028	631	1 521	3 473	44	817	6 470	0	0	19	123	14	0	4 357	11 718	170	0	13	0	98	0	307	77
		ES	5 473	2 658	1 454	2 726	35	11	2 354	0	0	4	0	0	0	3 348	2 790	201	0	10	0	NA	NA	160	40
		Weights	FLEX%	2	100 %	2	100 %	4	100 %	0	100 %	4	100 %	2	10 %	4	90 %	2	52 %	2	100 %	1	100 %	4	56 %
	Frequency Restoration Reserve: Manual (mFRR) : Upwards	DK	426	427	1 219	133	0	0	0	0	0	0	0	300	0	891	743	80	19	59	0	0	0	67	0
		IT	1 523	631	1 521	3 473	44	817	6 470	0	0	19	123	14	0	4 357	11 718	170	0	13	0	98	0	307	77
		ES	3 191	2 658	1 454	2 726	35	11	2 354	0	0	4	0	0	0	3 348	2 790	201	0	10	0	NA	NA	160	40
		Weights	FLEX%	2	100 %	2	100 %	4	100 %	0	100 %	4	100 %	2	10 %	4	90 %	2	52 %	2	100 %	1	100 %	4	56 %
Ancillary services for voltage control	Fault ride-through capability	DK		853	2 438	267	0	NA	NA	0	0	0	0	600	0	891	743	0	0	0	0	0	0	0	0
		IT		1 261	3 041	6 945	89	NA	NA	0	0	19	123	29	0	4 357	11 718	0	0	0	0	98	0	0	0
		ES		5 317	2 907	5 451	70	NA	NA	1	0	4	0	0	0	3 348	2 790	0	0	0	0	NA	NA	0	0
		Weights	FLEX%	4	100 %	4	100 %	NA	100 %	4	100 %	4	100 %	4	10 %	4	90 %	0	52 %	0	100 %	1	100 %	0	56 %
	Congestion magement_Voltage control	DK		640	1 829	267	0	0	0	0	0	0	0	600	0	668	557	40	9	0	0	0	0	0	0
		IT		946	2 281	6 945	89	817	6 470	0	0	19	123	29	0	3 268	8 789	85	0	0	0	98	0	0	0
		ES		3 988	2 180	5 451	70	11	2 354	1	0	4	0	0	0	2 511	2 092	100	0	0	0	NA	NA	0	0
		Weights	FLEX%	3	100 %	4	100 %	4	100 %	4	100 %	4	100 %	4	10 %	3	90 %	1	52 %	0	100 %	1	100 %	0	56 %
	Primary voltage control	DK		427	1 219	200	0	0	0	0	0	0	0	450	0	446	371	40	9	0	0	0	0	0	0
		IT		631	1 521	5 209	66	817	6 470	0	0	19	123	21	0	2 178	5 859	85	0	0	0	98	0	0	0
		ES		2 658	1 454	4 088	52	11	2 354	1	0	4	0	0	0	1 674	1 395	100	0	0	0	NA	NA	0	0
		Weights	FLEX%	2	100 %	3	100 %	4	100 %	4	100 %	4	100 %	3	10 %	2	90 %	1	52 %	0	100 %	1	100 %	0	56 %
	Secondary voltage control	DK		427	1 219	200	0	0	0	0	0	0	0	450	0	668	557	40	9	0	0	0	0	0	0
		IT		631	1 521	5 209	66	817	6 470	0	0	19	123	21	0	3 268	8 789	85	0	0	0	98	0	0	0
		ES		2 658	1 454	4 088	52	11	2 354	0	0	4	0	0	0	2 511	2 092	100	0	0	0	NA	NA	0	0
		Weights	FLEX%	2	100 %	3	100 %	4	100 %	0	100 %	4	100 %	3	10 %	3	90 %	1	52 %	0	100 %	1	100 %	0	56 %
	Tertiary voltage control	DK		427	1 219	200	0	0	0	0	0	0	0	450	0	668	557	0	0	0	0	0	0	0	0
		IT		631	1 521	5 209	66	817	6 470	0	0	19	123	21	0	3 268	8 789	0	0	0	0	0	0	0	0
		ES		2 658	1 454	4 088	52	11	2 354	0	0	4	0	0	0	2 511	2 092	0	0	0	0	NA	NA	0	0
		Weights	FLEX%	2	100 %	3	100 %	4	100 %	0	100 %	4	100 %	3	10 %	3	90 %	0	52 %	0	100 %	0	100 %	0	56 %

MW refers to the convesrsion of yearly genereated energy or load in GWh/year by dividing it by 8760*

11 Appendix D: Network modelling

11.1 ZIP Load model

Table 40: Load model depending on the nature of the device

$P = P_a(a_0 + a_1V + a_2V^2 + a_3V^{1.38})$ $Q = Q_b(b_0 + b_1V + b_2V^2 + b_3V^{1.38})$ $a_0 + a_1 + a_2 + a_3 = b_0 + b_1 + b_2 + b_3 = 1$			
Type	**Explanation**		**Load examples**
Constant Impedance (constant Z)	The load power varies with the square of the voltage magnitude	a_2 b_2	Electric heating Incandescent lighting Resistive heater Stovetop Oven cooking
Constant Current (constant I)	The load power varies with the voltage magnitude	a_1 b_1	Fluorescent lighting Welding units Smelting Electroplating
Constant Power (constant P and Q)	The load power does not varies with the voltage magnitude	a_0 b_0	Electric motors Regulated power supplies Inverters

11.2 Distribution grid model of NYFORS

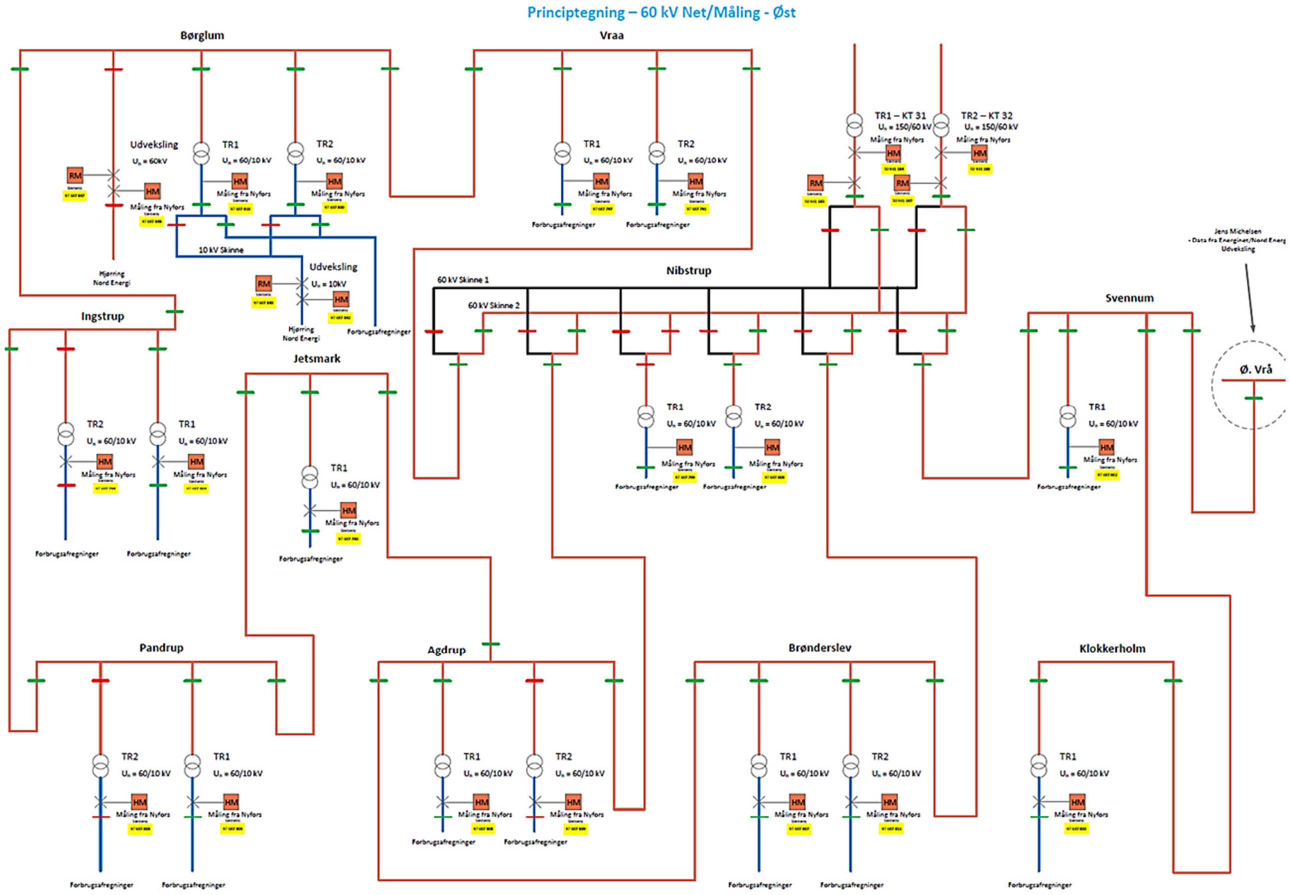


Figure 34: Eastern part of the sub-transmission grid operated by NYFORS

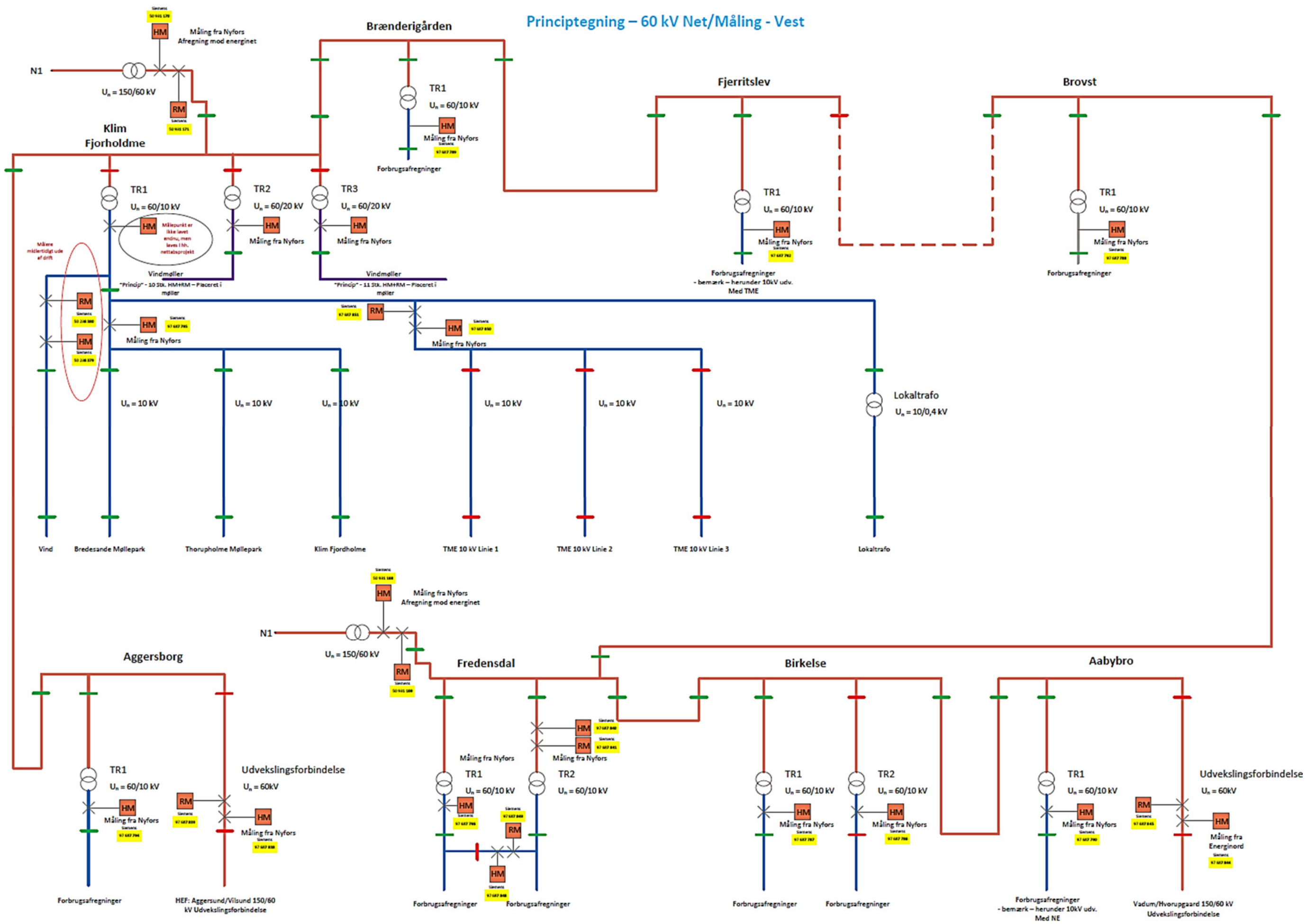


Figure 35: Western part of the sub-transmission grid operated by NYFORS

11.3 Representative network model for the Spanish pilot

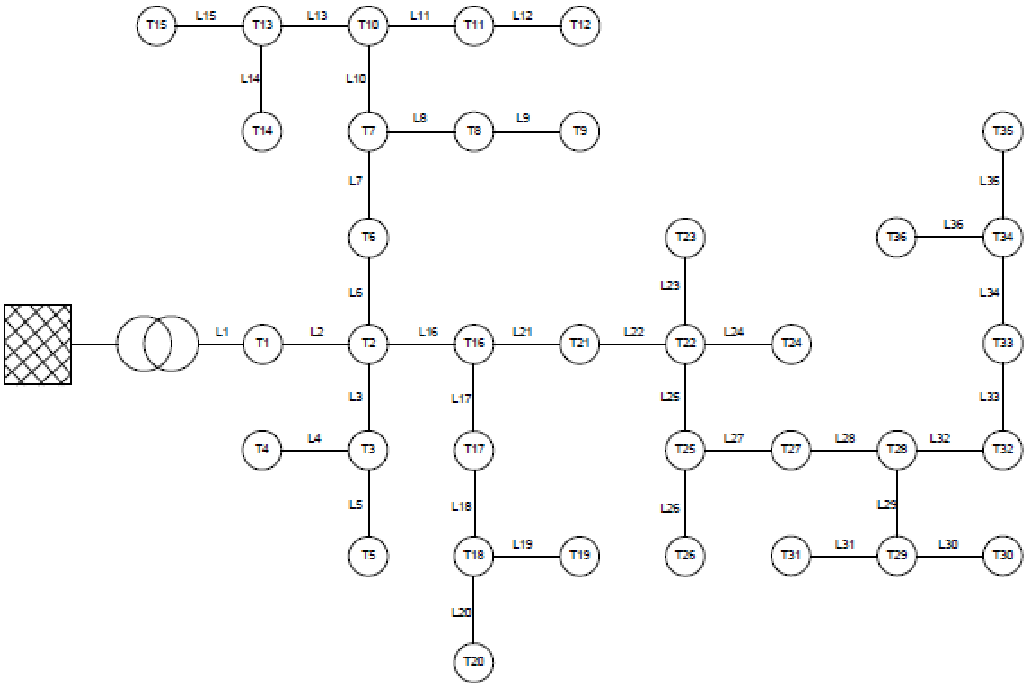


Figure 36: IEEE 37 nodes model [122]

Table 41: Proposed lines characteristics for the modified IEEE network model [122]

A [mm^2]	R [Ohm/km]	X_L [Ohm/km]	I_{max} [A]
240	0.125	0.116	415
400	0.0778	0.105	530

Table 42: Proposition of values for the transformer [122]

Feature	**Assigned Value**
Power	160-250-400-630 kVA
Connection type: 250-400-630 kVA	Dyn11
Voltage of the HV coupling	25 kV
No-load voltage of the LV coupling	420 V
Transformer's tap positions	-5 -2.5 0 $+2.5$ $+5$ $+10$
Capacity of resisting short-circuit events in the LV side	22.2 I_{nom}

Table 43: Features of the elements used in the grid [122]

Transformer station	Number of transformers	Pnom [kVA]	Line	L [km]	S [mm^2]
T0	1	25000	-	-	-
T1	1	160	L1	0.3	400
T2	3	250 + 250 + 400	L2	0.2	400
T3	1	400	L3	0.4	240
T4	2	160 + 250	L4	0.4	240
T5	1	160	L5	0.3	240
T6	1	400	L6	0.2	240
T7	1	250	L7	0.3	240
T8	2	250 + 250	L8	0.2	240
T9	1	400	L9	0.3	240
T10	1	160	L10	0.2	240
T11	2	250	L11	0.3	240
T12	1	250	L12	0.3	240
T13	2	250 + 250	L13	0.3	240
T14	1	160	L14	0.3	240
T15	2	250 + 630	L15	0.2	240
T16	2	630 + 250	L16	0.4	240
T17	2	400 + 160	L17	0.4	240
T18	1	250	L18	0.2	240
T19	1	160	L19	0.5	240
T20	2	250 + 160	L20	0.1	240
T21	1	250	L21	0.4	240
T22	2	160 + 250	L22	0.2	240
T23	2	160 + 250	L23	0.3	240
T24	1	630	L24	0.2	240
T25	2	250 + 400	L25	0.5	240
T26	2	400 + 250	L26	0.2	240
T27	1	160	L27	0.3	240
T28	1	400	L28	0.2	240
T29	1	160	L29	0.2	240
T30	2	250 + 250	L30	0.3	240
T31	1	250	L31	0.2	240
T32	2	160 + 250	L32	0.7	240
T33	1	400	L33	0.3	240
T34	2	160 + 250	L34	0.5	240
T35	2	400 + 250	L35	0.3	240
T36	1	400	L36	0.4	240

11.4 Market areas for the Italian transmission network

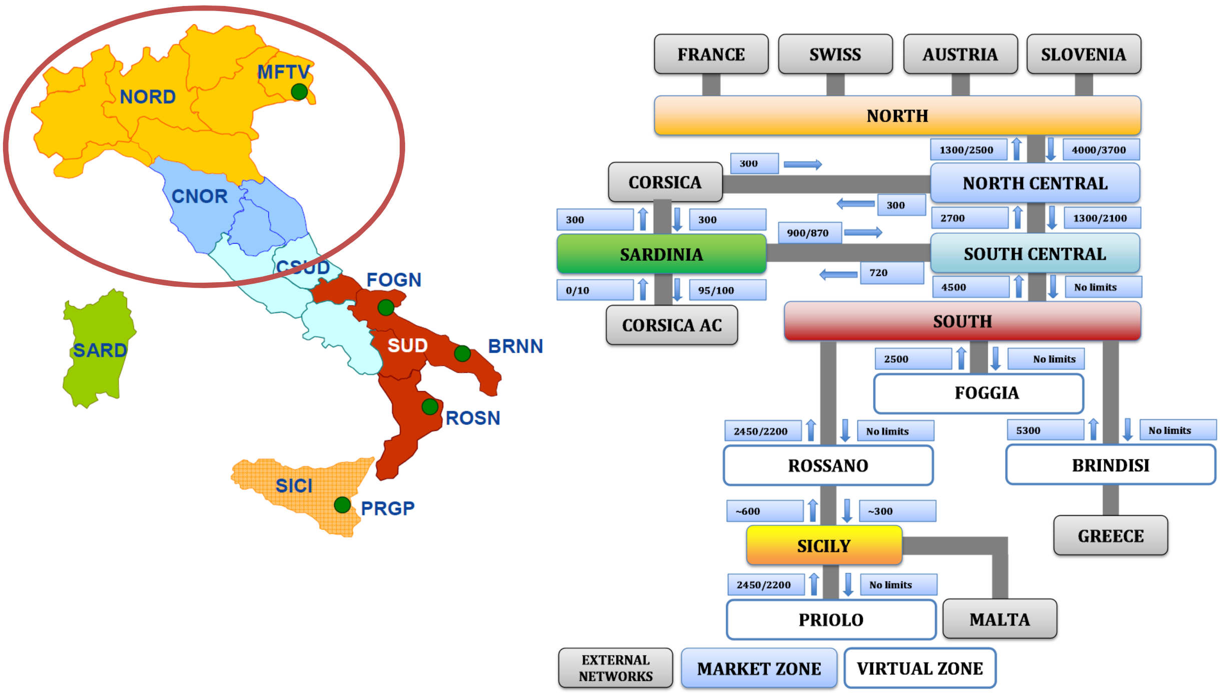


Figure 37: market areas schemes of the Italian transmission network (source:Italian Autority)