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D3.1

Benchmark of markets and regulations for electricity, gas and heat and overview of flexibility services to the electricity grid

Magnitude

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Lead Beneficiary: **EDF (Electricité de France):** Lionel Cauret, Regine Belhomme

Contributing beneficiaries:

EIFER (Europaisches Institut für Energieforschung EDF-KIT EWIV): Pauline Raux-Defossez, Jan Eberbach, Manuel Eising

Regenera Levante S.L.: Johannes Steinbeisser, Juana Maria Pagan Carpe

Efficacity: Stanislas Nösperger

Cardiff University: Muditha Abeysekera, Meysam Qadrdan

cyberGRID GmbH & Co KG: Christoph Gutschi

Danmarks Tekniske Universitet: Angelina Syrri

Mälardalens Högskola: Hailong Li, Eva Nordlander, Worrada Nookuea

Ricerca sul Sistema Energetico (RSE S.p.A.): Edoardo Corsetti

VITO (**Vlaamse Instelling voor Technologisch Onderzoek N.V.):** Kris Kessels

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Executive Summary

The present report is a public deliverable (Deliverable D3.1) of the MAGNITUDE H2020 funded European project. The MAGNITUDE project aims to develop business and market mechanisms, as well as supporting coordination tools to provide flexibility to the European electricity system, by enhancing the synergies between electricity, heating/cooling and gas systems. In particular, MAGNITUDE's goal is to identify possible flexibility options to support the cost-effective integration of Renewable Energy Sources (RES) and the decarbonisation of the energy system, and to enhance the security of supply.

To achieve its goals, MAGNITUDE will:

- Provide technological and operational tools to enable the provision of flexibility to the electricity system by Multi-Energy Systems (MES).
- Develop enhanced business and market mechanisms and identify potential regulatory evolutions to exploit the full potential value of the flexibility provided.
- Validate the project results on seven real life case studies (CS) of multi-energy systems of different sizes and technological features (including key "cross-sector" technologies), located in seven European countries (Austria, Denmark, France, Italy, Spain, Sweden, United Kingdom) with different regulations, support schemes, and geopolitical characteristics.
- Propose recommendations and contribute to the definition of policy strategies in a pan-European perspective and spread the project achievements towards stakeholders in the electricity, heat and gas sectors to raise awareness and foster a higher collaboration.

In this context, one of the first steps is to identify and describe the most relevant flexibility services that could be provided to the electricity system by MES to achieve the project goals. This is the main objective of this deliverable, along with the characterisation of the mechanisms for the procurement/provision of these services in the seven case study countries and a description of the gas and heating/cooling sectors, which will be affected by such provision of services to the electricity system. The provision of the services through enhanced synergies between the three sectors will then be further studied in the different Tasks and Work Packages (WPs) of the project.

As mentioned above, the analysis has been carried out for the 7 case study countries, namely Austria, Denmark, France, Italy, Spain, Sweden, and the United Kingdom. However, for this latter only Great Britain is considered and not Northern Ireland. The main outcomes are summarized below.

First the main needs of the electricity system have been described, as well as the services that can be procured/provided to meet them. Three main categories of needs have been distinguished: (i) needs of TSOs and/or DSOs, (ii) needs of States/policy makers (and subsequently also of TSOs), (iii) needs of energy sellers and buyers.

Among the long list of services resulting from this analysis, the most relevant ones have been selected using the following criteria, namely selection of services:

- that allow to increase the share of Renewable Energy Sources (RES), avoid curtailment of variable RES, enhance the security of supply,
- for which the enhancement of the synergies between electricity, heating/cooling and gas systems provide real opportunities,
- for which the first elements already collected by the project (technical, regulatory, market design) show a potential value for the provision by MES.

The resulting list of selected services is given in the table below.

Table 1 – Selected electricity system needs and services

Needs	Services
Frequency control and balancing	FCR (Frequency Containment Reserve)
	aFRR (Automatic Frequency Restoration Reserve)
	mFRR (Manual Frequency Restoration Reserve)
	RR (Replacement Reserve)
	+ Dedicated additional balancing mechanisms which may exist in certain countries.
Energy trades	Day ahead energy trades/market
	Intraday energy trades/market
System adequacy	Capacity requirement mechanisms
Congestion management at transmission and distribution levels	Re-dispatching mechanisms or active power control

It should be noted that:

- In the electricity system, the enhancement of the synergies between electricity, gas and heating/cooling systems will mainly have an impact on "energy" or active power. Therefore, the most relevant services are indeed those services linked to active power
- On the distribution networks, active power control or re-dispatching can also be used to control the voltage at MV level, which can therefore also be identified as a relevant service, in combination with the management of power flow constraints.
- For the reserve services, two different aspects or phases must be distinguished: (i) the procurement of the power reserves in order to guarantee the availability of the flexible resources when they will be needed, and (ii) the activation of the service and the actual energy delivery. Indeed, the procured reserves might not be activated. This distinction may also apply to capacity services, as well as to some procurement mechanisms of local power capacities to be used for congestion management.

After the above selection phase, the mechanisms existing in the 7 case study countries for the procurement of the most relevant services have been described and compared.

Regarding energy trades, because of the day-ahead and intraday energy market coupling mechanisms that are already in place in Europe, the major processes for the organisation of both types of energy markets are already similar in the considered countries, even if going further in the analysis, some country specificities can be found, regarding for instance the timelines involved, the product duration, etc.

For the other selected services, a larger diversity is observed in the 7 considered countries, and it is even truer for the capacity requirement mechanisms, which may take very different forms (organised markets, capacity payments, reserves) and even do not exist in some countries.

Some initiatives have been launched by TSOs and are ongoing in order to harmonize the procurement of balancing and frequency regulation services and support the implementation of the EC Guideline on Electricity Balancing [1], such as: the FCR cooperation, the PICASSO project for aFRR, the MARI project for mFRR, and the TERRE project for RR [2], as well as other regional initiatives.

For the gas sector, the main roles involved have been identified and the following market layers have been described for the 7 case study countries:

- the wholesale market: organisation, market platforms, products exchanged, trading times, and other country specificities,
- the retail market layer: organisation, description of the interactions between retailers and consumers, retail price structures,
- balancing of the gas system: organisation, roles involved, implemented mechanisms for the procurement of balancing services.

Like for the electricity system, although similarities can be found, the characteristics of the gas markets are rather heterogeneous between the case study countries, for instance in terms of the trading times, retail tariff structures, balancing mechanisms, etc.

The heating/cooling sector has also been described for the 7 case study countries, and the following aspects have been considered:

- the role of district heating in meeting national heat demand,
- the heat network regulation and the existing policies to promote district heating,
- the organisation of the heat sector and the main roles and stakeholders involved,
- the tariff structures.

A large diversity of situations, organisations and mechanisms can be observed in the different countries. Contrary to the electricity and gas sectors, there is no unbundling in the heat sector. So, the network operator role can be carried out by a player being also a heat producer and/or the heat supplier of the consumers connected to the district heating network.

In the heat sector, there is generally no “organised” markets as such, even though, some sort of heat market mechanisms can sometimes be found involving a day ahead planning and intraday adjustments between the heat producers and the operator of the mechanism, like for the integrated heat market implemented in the Greater Copenhagen area in Denmark.

Comparing the roles involved in the electricity, gas and heating/cooling systems, there are a lot of similarities. Indeed, the three sectors have:

- Distribution networks and transmission networks (mainly distribution networks for the heat sector but transmission networks can sometimes be found like in the Copenhagen area in Denmark) and therefore the corresponding roles of distribution and transmission network operators.
- The roles of producers, suppliers, consumers, storage operators, etc.
- A balancing requirement between generation and consumption and therefore the associated balancing responsible role.
- Metering-related roles, etc.

These similarities will undoubtedly help in the enhancement of the synergies between the three sectors.

However, regarding operation and market aspects, the characteristics of the electricity, gas and heat networks are rather different in terms of time constants, inherent resilience and dynamic behaviours, and therefore the associated operation needs and requirements also differ considerably.

Finally, potential market and regulatory barriers or shortcomings have been discussed. The following main categories have been identified, namely barriers or shortcoming due to:

- The diversity of situations, market mechanisms and rules that can be found in the considered countries:
  - diversity between countries, and
  - diversity between electricity, gas and heat sectors.
- Specific rules or requirements preventing or limiting the provision of services by MES (such as for instance minimum bid size or mechanisms that do not allow demand response or aggregation in some countries).
- Additional or increased costs that may be caused for instance by network tariffs, retail prices, imbalances, or inherent fixed and variable operation costs of MES.
- Insufficient attractiveness of flexibility services remuneration to cover all the costs incurred.
- Lack or incompatibility of incentive schemes, for instance
  - to encourage DSOs to procure flexibility services,
  - between RES support schemes and the provision of flexibility services.
- Lack of coordination between network operators:
  - between DSOs and TSOs in the electricity system,
  - between electricity, gas and heating/cooling network operators.
- The large diversity of stakeholders with deeply different professional culture, implying both:
  - complexity and numerous interactions/transactions,
  - needs for awareness raising, learning and training.

Increasing synergies between electricity, gas and heating/cooling systems will therefore require to take into account the specificities of the three sectors both at the national and local scales. Indeed, it should be kept in mind that heat networks are inherently local systems and rather heterogeneous situations can be met from one area to the other and from one MES to the other.

This deliverable provides a description and comparison of the main characteristics of the procurement mechanisms for the selected services in the seven case study countries. These results are then used in other work packages of MAGNITUDE, for instance to:

- carry out a qualitative assessment of the technical capabilities of the technologies involved in the case studies to provide the selected services,
- identify the services that will be further studied and simulated for each case study and to define the project use cases,
- guide modelling and development choices to be made for the project use cases.

This characterisation will also be further completed with detailed targeted information collected to study the use cases defined for each case study.

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List of Acronyms

Abbreviation / Acronym	Description
CHP	Combined Heat and Power
COS	Commercial Operative Storage
CR	Complementary Reserve
CRE	Commission de Régulation de l'Energie (French regulator)
CRM	Capacity requirement mechanism
CS	Case Study
DA	Day Ahead
DERA	Danish Energy Regulation Authority
DH	District Heating
DTU	In Great Britain: Demand Turn Up
DSO	Distribution System Operator
EBGL	European Commission guideline on electricity balancing
EC	European Commission
EFR	Enhanced Frequency Response
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
FAT	Full Activation Time
FCFS	Capacity Orders placed by a shipper
FCR	Frequency Containment Reserve
FFR	Firm Frequency Response
FRR, aFRR, mFRR	Frequency Restoration Reserve, automatic FRR, manual FRR
GB	Great Britain
HP	Heat Pump
ID	Intraday
IE	Ireland
LV	Low Voltage
MES	Multi-Energy System
MFR	Mandatory Frequency Reponse
MMcm	Million cubic meters
MV	Medium Voltage
NBP	National Balancing Point

Abbreviation / Acronym	Description
NI	Northern Ireland
OFGEM	Office for Gas and Electricity Market
OTC	Over-the-Counter
PCR	Price Coupling of Regions
PVB	Virtual Transmission Balancing Point
RES	Renewable Energy Sources
RPM	Regulating Power Market
RR	Replacement Reserve
SO	System operator
STOR	Short-Term Operating Reserve
TMPC	Trans-Mediterranean Pipeline Company
TOP	Take-or-pay
TPA	Third-party access
TSM	Technical System Manager
TSO	Transmission System Operator
TTPC	Trans-Tunisian Pipeline Company
UK	United Kingdom
UNC	Uniform Network Code
VTP	Virtual Trading Point
WD	Within-day
WP	Work Package

1 Introduction

The present report is a public deliverable (Deliverable D3.1) of the MAGNITUDE H2020 funded European project.

1.1 MAGNITUDE project

The MAGNITUDE project aims to develop business and market mechanisms, as well as supporting coordination tools to provide flexibility to the European electricity system, by enhancing the synergies between electricity, heating/cooling and gas systems. In particular, MAGNITUDE's goal is to identify possible flexibility options to support the cost-effective integration of Renewable Energy Sources (RES) and the decarbonisation of the energy system, and to enhance the security of supply.

To achieve its goals, MAGNITUDE will:

1. Provide technological and operational tools to enable the provision of flexibility to the electricity system by Multi-Energy Systems (MESs).
2. Develop enhanced business and market mechanisms and identify potential regulatory evolutions to exploit the full potential value of the flexibility provided.
3. Validate the project results on seven real life case studies (CS) of multi-energy systems of different sizes and technological features (including key "cross-sector" technologies), located in seven European countries with different regulations, support schemes, and geopolitical characteristics (Austria, Denmark, France, Italy, Spain, Sweden, United Kingdom).
4. Propose recommendations and contribute to the definition of policy strategies in a pan-European perspective and spread the project achievements towards stakeholders in the electricity, heat and gas sectors to raise awareness and foster a higher collaboration.

MAGNITUDE addresses the challenge to bring under a common framework, technical solutions, market design and business models, to ensure that its results can be integrated in the overall ongoing policy discussion in the energy field.

1.2 Objectives and scope of Deliverable D3.1

In this context, one of the first steps is to identify and describe the most relevant services that can be provided to the electricity system by MES. This work has been carried out in Work Package 3 of the project (see the project structure in [3]) and the results are given in the present deliverable.

More specifically the objectives of Deliverable D3.1 are to provide:

- An overview of the most relevant services towards the electricity system, which allow to increase the share of Renewable Energy Sources (RES), avoid curtailment of variable RES and enhance security of supply. These services should also allow to increase the synergies and trading between electricity, gas and heat/cooling networks: this capability will be studied in other Tasks and Work Packages of the project.
- For the most relevant services identified, a comparative analysis of the associated electricity markets and/or service provision mechanisms, including the following aspects: market mechanisms and

regulations, products exchanged, remuneration and/or tariffs systems, main stakeholders involved and the key relationships.

- A comparative analysis of market segments for the gas and heat sectors, which will be affected by the service provision. To the extent possible, this analysis will also cover the market mechanisms and regulations, the products exchanged, the remuneration and/or tariffs systems, the main stakeholders involved and the key relationships.
- The identification of market and regulatory barriers that might affect the provision of the services.

The analysis is carried out for the case study countries, namely Austria, Denmark, France, Italy, Spain, Sweden, and the United Kingdom. However, for this latter, only Great Britain is considered and not Northern Ireland.

1.3 Methodology

The methodology applied to produce this deliverable is described below for the three considered sectors: electricity, gas and heat/cooling.

For the electricity system, the following steps were carried out:

1. Identification of the key needs of the electricity system and of the associated services procured to meet these needs (Section 2.1).
2. Selection of the most relevant services to be considered for the provision by Multi-Energy Systems (MES). The following main selection criteria, directly linked to the project goals and expected impacts (see Section 1.2 above), were used:
    - increase the share of Renewable Energy Sources (RES),
    - avoid curtailment of variable RES,
    - enhance the security of supply.

   Other factors were also considered in the selection, such as first elements on the potential value for the provision of the services by MES.
   The results of this step are provided in Section 2.2.
3. Collection of information by means of a detailed questionnaire on the provision of the selected services in each of the 7 case study countries (Austria, Denmark, France, Italy, Spain, Sweden, and United Kingdom).
4. Description and comparison of the national mechanisms and exchanged products, based on the analysis of the collected information at the previous step and complemented with information collected through a literature survey. The detailed results of this description are given in Appendix 7.1 and are summarized in Section 3.1.
5. Identification of potential barriers and shortcomings (Section 4).

Throughout the work, a literature review was conducted on reference documents (such as legal and regulation texts, network codes, EC documents, reports produced by TSOs and regulators…) and on reports produced by other relevant projects or organisations (e.g. SmartNET, EirGrid, smartEN, MARI, TERRE…). The references used can be found in Section 6. In particular the upcoming European harmonization linked to the networks codes has been taken into account, such as the European guideline on electricity balancing (EBGL) [1].

In the analysis, we also made sure to consider the global framework of the MAGNITUDE project, namely:

- market-based approach (in the most general way, i.e. including not only organised markets, but also OTC trading, call for tenders…),
- provision of the services through aggregation, which is a central concept in MAGNITUDE.

Finally, it should be kept in mind that there are specificities in the different considered countries even if similar electricity system needs exist in all of them. For instance:

- The "frontier" between transmission and distribution levels varies widely depending on the country (e.g. 20 kV in France, 110 kV in the United Kingdom). The rules applied to the provision of the services, in particular by MES, can be affected by this situation.
- The services and the mechanisms to procure them can sometimes be very different, e.g.:
    - The "frontiers" between balancing, ancillary services and (re)dispatching and the associated characteristics can be different from one country to the other, in particular these mechanisms can be more or less combined depending on the country.
    - Whatever these frontiers, each mechanism in place answers to the specific needs of its national power system, affecting the following four elements: upstream procurement process, activation process, remuneration/penalty regime afterwards and system cost recovery mechanisms.
    - Some services do not exist in some countries while several specific services may be found in other countries.
- The terminology may differ depending on the country, e.g. the same name can be used to denote different services or inversely the same service can be given different names.

For the gas and heat sectors, a similar, although simplified, methodology was applied as the main focus of the MAGNITUDE project is the provision of services to the electricity system. The gas and heat systems are therefore not considered in detail but only to the extent that they may affect this provision. The following steps were carried out:

1. Collection of information on the gas and heat sectors in the seven case study (CS) countries on regulations, market mechanisms or service provision processes, products exchanged, remuneration or tariff systems, main stakeholders involved and key relationships, as well as elements on potential market and regulatory barriers. For the heat sector, the report mainly focuses on district heating or heat networks.
2. Description and comparison of the gas and heat systems in the CS countries, based on the analysis of the collected information. The results of this description are given respectively in Section 3.2 for the gas sector and in Section 3.3 for the heat sector.
3. Identification of potential barriers and shortcomings (Section 4).

2 Most relevant services towards the electricity system

2.1 Electricity system needs and associated services

The electricity system is a very complex system to operate and manage in order to ensure that supply and demand are balanced at any time, efficiently (from a physical and economic perspective) and securely, under uncertainty. That is why a temporal hierarchy of decisions is implemented. This ranges from the long-term perspective of generation investments and grid expansion planning up to five years ahead or more, to the very short term or even real time with actions carried out in less than one hour or even less than one minute. Furthermore, the power system complexity is increasing as a consequence of fundamental evolutions such as the present and future expected changes in the energy mix (more intermittent distributed generation hardly predictable, less synchronous generation…).

This section gives an overview of the needs of the electricity system and the associated services to meet them. Three types of key needs are distinguished:

- Needs of the system operators, namely the Transmission System Operators (TSOs) and Distribution System Operators (DSOs), who are responsible for the real time operation of the electricity system to ensure the physical match between supply and demand (balancing) and to maintain the system/network operational parameters within their optimal range (voltage, frequency, power flows…).
- Needs for the States/policy makers and for the TSOs to guarantee the system adequacy one or several years ahead (capacity mechanisms for security of supply).
- Needs of energy sellers and buyers to trade energy between, on one side, generators, aggregators, etc., and on the other side, suppliers, large consumers, etc.

The definition of the products exchanged to meet these needs in each country and the associated market mechanisms will be described in detail in Appendix 7.1 and summarized in Section 3.1.

2.1.1 Main needs of TSOs and/or DSOs and associated services

Voltage control (security of the system)

Transmission and distribution networks need to operate within a prescribed voltage range. The acceptable values usually vary depending on operational standards and grid codes in different countries [4]. In particular, the European standard EN 50160 defines the voltage characteristics of electricity supplied by public distribution systems.

Voltage control is the process to maintain the voltage within a predefined range (very short term or short term). The voltage is a local network feature (i.e. not system-wide) referring mainly to the local balance between the reactive power production (until now mainly provided by conventional generators and grid equipment, e.g. capacitor banks) and absorption (by consumers and networks). An imbalance can decisively influence the transmission and distribution networks (risk to increase losses and, in case of huge reactive power imbalance, to weaken the system security) and the end users equipment (risk of material damages, malfunctions), even if its impacts are not transmittable over long distances. That is why voltage control needs to be organised at a local level. Additionally, voltage control becomes more complex because of the massive integration of renewable generation, which reduces the share of conventional synchronous generators, and eventually the overall ability to provide reactive power.

At the distribution level, the connection of renewable generation plants modifies the voltage (increase of the voltage at the connection point) and might lead to voltage constraint violations.

The following services are associated to voltage control:

1. **Manage voltage deviations (primary voltage control):** on the transmission grid, maintains the voltage at the connection point of the generator close to a voltage reference given by the TSO.
2. **Maintain admissible voltage band – automatic (secondary voltage control):** on the transmission grid centralized automatic control that coordinates the actions of local regulators in order to manage the injection of reactive power within a regional zone.
3. **Maintain admissible voltage band – manual (tertiary voltage control)**: on the transmission grid refers to the manual optimisation of nodal voltages and reactive power flows in the network.
4. **Power factor control or reactive power control:** the power factor is the ratio between the active power and the apparent power. It is a function of the active and reactive powers and is often used as an indirect way to control the reactive power on the grid. Depending on the capability of the equipment, direct reactive power control may also be provided.
5. **Active power control or re-dispatching**: on radial MV distribution grids the control of active power can also be used to solve voltage constraints. Due to the technical characteristics of the MV lines, active and reactive powers are much more “coupled” on the distribution networks than on the transmission networks (and this effect is even larger on LV feeders). Therefore, modifications of the active power of well-located producers or consumers can be used to control the voltage and appear as an efficient mean to do so (e.g. see [5], [6], [7]).

Power quality management

Power quality is related to the interactions between the network and its users (both generators and consumers) and depends on both the quality of the voltage and the current. Power quality is linked to the powering and grounding of equipment in a manner that is suitable to the operation of that equipment. It is a local feature but can have some impacts on the security of the system [8].

Power quality management enables a good functioning of the appliances and devices in a reasonably-disturbed system: a certain level of quality disturbances can be accepted within certain limits.

The main services usually associated to power quality management consist in the damping low order harmonics, injection of negative sequence voltage to compensate voltage unbalance between the three phases, and mitigation of voltage fluctuations and “flicker” (often a mandatory condition to be connected to the grid).

1. **Damping of low order harmonics**: harmonics on the grid can cause for instance extra heating of the cores of transformers and electrical machines, or malfunctions of some equipment. They can be induced by power electronics converters connected to the grid. Damping of low order harmonics can be achieved for instance through the installation of appropriate harmonics filters or more advanced power electronics converters. This service is generally mandatory. It implies the obligation to respect certain standards, which specify limit values, and is usually not remunerated.
2. **Injection of negative sequence voltage**: voltage unbalance between the three phases of the network can result in adverse effects on equipment (e.g. malfunction of three-phase devices) and on the power system, which will incur more losses and may be less stable. A first step is to respect the voltage

unbalance limits specified in standards. When going further, the service may consist in injecting negative sequence voltage in the grid to restore the balance between the phases.

3. **Mitigation of voltage fluctuations and flicker**: voltage fluctuations can be caused by rapid variations of loads or generators connected to the grid (e.g. arc furnaces, large motors, wind turbines – if not compensated, etc.). These voltage fluctuations can cause malfunctions, efficiency deterioration and even damage to equipment connected to the grid in the same area where they are generated. Again it implies a mandatory respect of standards which specify limit values. It is not remunerated and is often a mandatory condition for grid connection. Mitigation of voltage fluctuations and flicker can be achieved through the use of power electronics-based devices such as STATCOM, Dynamic Voltage Regulators, Static Var Compensators, etc.

Frequency control and balancing (reliability and security of the system)

Frequency is a system-wide feature (i.e. not localized) impacting the European synchronous network as a whole. It reflects the balance between the active power generation and consumption which must be maintained at all times in the power system.

The reference value or nominal frequency is fixed at 50 Hz in Europe. Frequency deviations from the reference value are caused by more or less significant events impacting the power system such as short-circuits, loss of a power plant or of a large consumption area, etc. These deviations can be more or less fast and severe depending on the steepness and volume of the generation or consumption decrease or increase.

Frequency control is applied to restore and maintain the balance between generation and consumption. In the EU guideline on electricity balancing [1], "*balancing means all actions and processes, on all timelines, through which TSOs ensure, in a continuous way, the maintenance of system frequency within a predefined stability range as set out in Article 127 of Regulation (EU) 2017/148*".

Synchronous generation plants and load shedding of big industrial consumers have already been key components of frequency control for a long time. But the contribution of conventional generation plants to frequency control is currently being reduced because of their decreasing share in the capacity and energy mix as a consequence of the huge penetration of renewables. They can be now complemented by other resources including non-synchronous generation (wind farms, storage), demand response of other types of consumers, and multi-energy systems (which will be studied in the MAGNITUDE project).

Frequency control globally consists of several successive mechanisms and associated services, illustrated in Figure 1:

1. **Containment of the frequency after the occurrence of an imbalance** over the European synchronous network (security at stake). That is the role of the Frequency Containment Reserve (**FCR**), defined by the EU Guideline on electricity transmission system operation [9] as "*the active power reserves available to contain system frequency after the occurrence of an imbalance*". This primary control starts within seconds as a joint action for all parties involved, when the frequency deviation exceeds a pre-defined level. The full activation of these reserves is requested when the deviation exceeds +/- 200 mHz (EU), +/- 500 mHz (Great Britain and Nordic countries), within 10s (IE/NI), 15s (Great Britain) or 30s (EU, Nordic countries). The reserve volume for the European Continental synchronous area is equal to 3000 MW.

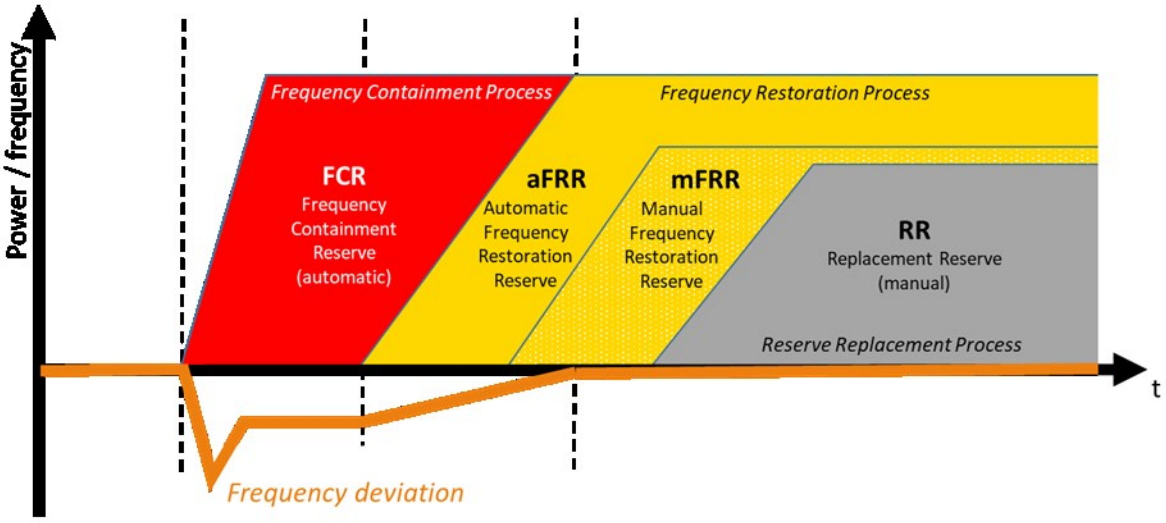

Figure 1 - Dynamic hierarchy of Frequency Control (based on [10])

2. **Restoration of the nominal frequency after the occurrence of an imbalance.** This is the role of the Frequency Restoration Reserves (FRR), defined by the above mentioned EU Guideline as "*the active power reserves available to restore system frequency to the nominal frequency and, for a synchronous area consisting in more than one Load-Frequency Control area, to restore power balance to the scheduled value*". This secondary control replaces the frequency containment process after some minutes (full activation time of 5 to 15 min) in order to restore the FCR. The FRR can be activated by an automatic control process (**aFRR**) or manually (**mFRR**).
3. **Restoration of the nominal frequency after the occurrence of an imbalance and support of the required level of FRR to be prepared for additional system imbalances**. That is the role of the Replacement Reserves (**RR**), defined by the above mentioned EU guideline as "*the active power reserves available to restore or support the required level of FRR to be prepared for additional system imbalances, including generation reserves*". This replacement reserve process partially complements and finally replaces FRR usually by re-scheduling generation.

For the above frequency regulation mechanisms, two different aspects or phases should be distinguished:

- The procurement of power reserves in order to guarantee the availability of flexible resources when they will be needed.
- The activation of the reserves in case of frequency deviation and the actual power delivery.

Indeed, the procured reserves might not be activated.

Let us finally add that the **EC guideline on electricity balancing** (**EBGL**) [1] encourages the introduction of platforms to harmonize the rules to enable the exchange of balancing energy for frequency restoration reserves and replacement reserves. For instance in late 2017, the EU defined a plan aiming to harmonize the national balancing systems within 2023. Initiatives managed by some TSOs related to this harmonisation (FCR Cooperation, TERRE, PICASSO, etc.) are detailed in Section 3.1.4.

System restoration in case of a partial or full blackout (emergency and security of the system)

The risk of a total or partial blackout of the transmission system caused by large disturbances such as severe short-circuits, extensive losses of generation, always exists with huge potential impacts on the population, industries and national/regional activities as a whole. That is why all power systems continuously prepare appropriate measures to restore the system in case of a blackout. However, such a system restoration is very complex and requires a series of successive coordinated actions at the local and central levels.

The associated relevant service is:

- **Black start capability**: it is provided by generators that have the capability to restart main generation units from an on-site auxiliary generator, without reliance on the main grid and that can contribute to system restoration by supplying parts of the network loads. This implies the capability to accept instantaneous loads and to control the frequency and the voltage in order to maintain them within acceptable limits during the block loading process.

Congestion management, incl. cross-border congestion (security of the system)

A congestion appears as soon as the forecasted or real physical power flows exceed the physical capability of the grid components (cables, lines, transformers, etc.). This situation can occur on transmission or distribution networks, as well as on interconnections between countries and transmission systems. Congestions also need to be considered for N-1 situations, namely when a contingency occurs on the grid.

Congestion situations can increase on the one hand due to the huge development of renewables, often far from consumption centres and sometimes in areas where the networks were not initially designed for these additional flows, and on the other hand due to the growing electrification of some end-uses (e-mobility, electrical heating…). An appropriate development and operation of the grids is therefore needed in order to manage these growing congestions risks.

Management of congestion risks is the responsibility of the System Operator (SO). Depending on whether a risk of congestion is more or less anticipated, several options are possible for the SO. Two main categories of approaches implementing in particular active or reactive power control can be distinguished: direct control of different types of resources on the grid and use of market-based approaches.

1. In the first category, the SO can directly control resources such as
    - modify temporarily the grid configuration and topology;
    - use technical means at its disposal such as transformer taps/phase shifters, FACTs (Flexible Alternating Current Transmission Systems), etc.
    - use direct reactive power control;
    - use direct active power control;
    - curtail RES;
    - in the longer term, reinforce the grid concerned.

2. In the second category, the SO can use market-based approaches such as (some of them are not deployed yet):
    - use the balancing mechanism to also solve physical network constraints while matching power trades in energy markets;
    - use countertrading[1] or external re-dispatching[2];

[1] "Countertrading" means a "cross zonal exchange initiated by system operators between two bidding zones to relieve a physical congestion" (Article 2(13) of the Regulation on submission and publication of data in electricity markets), as mentioned by https://www.emissions-euets.com/internal-electricity-market-glossary/714-countertrading.

[2] "External re-dispatching" means that the re-dispatching is performed in another bidding zone than the bidding zone where the congestion occurs.

- use price signals (ex.: day-ahead dynamic tariffs; or where central dispatch applies, locational marginal pricing or nodal pricing as in six regions of the USA [11], etc.);
- procure RES curtailment services;
- procure potential flexibility services from electricity consumers;
- contract in advance the availability of distributed resources (capacity service) that will be able to address the congestion when needed;
- introduce adequate methods for (cross-border) transport capacity allocations.

The associated services are described in more detail in Section 3.1.5.

Other future relevant electricity system needs

Other future relevant electricity system needs and potentially new services are currently being discussed and studied in different projects (e.g. see [12], [13], [14], [15], [16]). Some examples are given below:

- **Minimization of grid losses**
  The reduction of network costs is an important objective of TSOs and DSOs and in particular the minimisation of grid losses. Indeed, grid losses lead to energy expenditures for TSOs and DSOs who have to purchase the associated energy in the energy markets or through specific mechanisms. These costs then have to be allocated to network users in one way or another, for instance through network tariffs and/or fees.
  The grid losses are function of the power flows and therefore depend on the location and power injection or consumptions of the grid users.
  Potential future associated services: in order to optimise the grid losses, re-dispatching services might be procured from producers, consumers or storage providers in the form of specific remunerated requests of modifications of their active and/or reactive powers not for security but for economic or grid operation efficiency reasons.

- **Additional ramping services (contributing to frequency control and balancing)**: new needs in terms of ramping requirements and mainly upwards ramping (i.e. increase of generation over a specific time duration) are emerging in order to manage the variability and uncertainty of high levels of variable RES penetration. Existing services such as FCR, FRR and RR (see above) which already address the electricity system generation ramping needs, might not be sufficient and new potential services are being considered, such as the Ramping Margin service.

  The **Ramping Margin service** would consist in guaranteeing at a certain point in time a ramping margin product with a horizon and duration specified by the TSO that could be delivered by the participating unit. In other words the Ramping Margin represents the increased MW output that can be delivered by the specified horizon time and sustained for the specified duration (e.g. horizons of one, three and eight hours with associated durations of two, five and eight hours respectively as proposed in [16]).

- **Inertial response:** the electricity system inertia is an important factor that has a direct impact on its resilience to severe disturbances/changes that affect the frequency. Namely the maximum rate of change of the frequency is inversely proportional to the system inertia and therefore, the lower the system inertia, the faster the frequency will vary following short-circuits, or important loss of generation or consumption. The system inertia is mainly provided by conventional synchronous generators. With the increasing penetration of non-synchronous generation, such as RES or other resources connected through power electronics converters, the inertia of the system will decrease.

Potential future associated service: provision of inertial response. The synchronous inertial response is the response in terms of active power output and synchronising torque that a unit can provide following disturbances. It is naturally provided by synchronous rotating machines but can be emulated by other technologies (e.g. wind turbines, storage) provided that they have been properly designed and technically equipped to contribute to inertia emulation (which of course implies additional costs).

2.1.2 Needs for the States/policy makers and for TSOs

System adequacy (security of supply)

System adequacy refers to the necessary ability of the power system to supply the aggregated electrical demand and the associated energy requirements at all times in the future (medium and long term).

In this respect, in each country the main objective for the State and the TSO(s) is to guarantee the future security of supply, or in other words that the future generation mix will be able to supply the future demand (plus a reserve margin to account for unexpected events) in one, four or ten years from now.

In addition, potential investors should receive the right signals to invest in existing or new capacities at the right time, in particular in periods of uncertainties.

For these reasons, some European member states have decided to implement mechanisms for the remuneration of capacity.

These **capacity requirement mechanisms** may take very different forms depending on the country. For instance, the Final EC Report of the Sector Inquiry on Capacity Mechanisms [17] describes existing national mechanisms in place and insists on the importance to implement a rigorous adequacy assessment.

The capacity requirement mechanisms implemented in the case study countries will be further explained and described in Section 3.1.3.

2.1.3 Needs of energy sellers and buyers

The main needs of energy sellers and buyers are to reduce their price risks and optimize their energy portfolios.

In this respect, there are several mechanisms for the trade of energy between buyers and sellers:

1. **Long term energy contracts** to reduce financial risks by hedging, selling or buying a certain amount of electricity for delivery in the future, in respect of European rules. Futures are contracts to deliver/consume a certain amount of electricity at a certain time in the future for a price agreed upon today.
2. **Forward energy trades** (i.e. more than day-ahead): forward trades like futures are also contracts to deliver/consume a certain amount of electricity at a certain time in the future for a price agreed upon today. Forwards are traded bilaterally or via an intermediated place for bilateral contracts. Traded products are not necessarily standardized. However, they are often the same as those proposed by the futures.
3. **Day-ahead energy trades**: they have important physical implications because of the high volumes traded. Market participants trade on their expectations for each hour or half-hour of the next day, before a deadline every day (gate closure). Electricity can be traded bilaterally (OTC trading) or on a day-ahead power exchange (BELPEX, EPEX…).
4. **Intraday energy trades:** they allow to update and optimize trading positions just a few hours or even (tens of) minutes before the physical meeting of supply and demand. Due to information becoming

available after the gate closure of the day-ahead market, like new forecasts for renewables, plant outages or changed demand situations, the participants better know their power positions. The intraday energy trades can be operated up to 60 or 30 minutes before the real time (or even less in some countries, e.g. until 5 minutes before the delivery begins). Note that the intraday market is directly managed by a market operator and used for trades by market players (generators, aggregators, suppliers, large consumers, etc.) whereas the balancing market is managed by the TSO.

Both day-head and intraday energy trades are associated with the balancing obligations of the Balance Responsible Parties (BRP).

A Balance Responsible Party (BRP) "*is a market participant or its chosen representative responsible for its imbalances*" in the electricity market [1]. The BRP portfolio (of injections, consumption, contracts and trades) should be balanced at time of delivery. The BRP is financially responsible for keeping its own position (sum of his injections, withdrawals and trades) balanced over the imbalance settlement period (see below). The BRP is also responsible for the imbalances to be settled with the connecting TSO. The BRP is then reputed to have a short (respectively long) position if the difference between its contractual value and its metered and/or estimated position[3] has contributed to a deficit (respectively surplus) of electricity flowing into the system. An imbalance charge is then imposed per imbalance settlement period via the imbalance settlement [18]. EU (art. 17) [1] also adds that:

- "*Prior to the intraday cross-zonal gate closure time, each balance responsible party may change the schedules required to calculate its position pursuant to Art. 54. TSOs applying a central dispatching model may establish specific conditions and rules for changing the schedules of a balance responsible party*".
- "*After the intraday cross-zonal gate closure time, each balance responsible party may change the internal commercial schedules required to calculate its position pursuant to Article 54 in accordance with the rules set out in the terms and conditions related to balancing set up pursuant to Article 18*".

Imbalance settlement is "*a financial settlement mechanism for charging or paying balance responsible parties for their imbalances*" [1]. Each national scheme is globally defined by: (i) the settlement period, i.e. the time unit for which BRP imbalance is calculated; (ii) the area in which an imbalance is calculated; (iii) an imbalance price for each settlement period for an imbalance in each direction; (iv) the allocated volume physically injected or withdrawn from the system and attributed to a BRP[4].

2.2 Selection of the most relevant services

Starting from the above lists of electricity system needs and associated services, the selection of the most relevant services for the provision by MES to be considered in the project was carried out using the selection criteria described in Section 1, namely services:

- that allow to increase the share of Renewable Energy Sources (RES), avoid curtailment of variable RES, enhance the security of supply,
- for which the enhancement of the synergies between electricity, heating/cooling and gas systems provide real opportunities,

[3] For a supplier with small customers (households and small businesses), all the demand is not yet is metered: some quantities are just allocated based on assumed synthetic load profiles.

[4] Further information on imbalance settlement are available in [247].

- for which the first elements already collected by the project (technical, regulatory, market design) show a potential value for the provision by MES.

It should be noted that, in the electricity system, the enhancement or the optimisation of the synergies between electricity, gas and heat systems will mainly have an impact on the "energy" or in other words on the active power. Therefore, the most relevant services are those services that are linked to active power.

The selected needs and services are given in Table 2 below. They will be described in detail in Section 3.1 and compared for the case study countries.

Table 2 - Selected most relevant electricity system needs and services

Needs	Services
Frequency control and balancing (reliability and security of the system)	FCR (Frequency Containment Reserve)
	aFRR (Automatic Frequency Restoration Reserve)
	mFRR (Manual Frequency Restoration Reserve)
	RR (Replacement Reserve) and/or CR (Complementary Reserve)
	+ Dedicated additional specific balancing mechanisms which may exist in certain countries. They have strong links with the intraday market, and with mFRR and RR.
Energy trades + associated balancing obligations of BRP (and possible procurement of services)	Day ahead energy market
	Intraday energy market
System adequacy (security of supply)	Capacity requirement mechanisms
Congestion management at transmission and distribution level (security of the system in real-time)	Re-dispatching mechanisms or active power control
Voltage control in MV distribution grid (security of the system)	Active power control or re-dispatching on distribution grids (MV level). NB: this service is often combined with the previous one (see below).

Discussion on the selection of the most relevant services to be considered in MAGNITUDE

- **Voltage control**:
  - In most cases, voltage control is a mandatory service with a local anchorage. Except for the last service in Table 2, it is being carried out by acting on reactive power at the connection point and will depend on the reactive power control capabilities of the equipment connected to the grid. Enhanced synergies between energy carriers are expected to have a low (or even no) impact on the reactive power control. This service will therefore not be considered within the MAGNITUDE project.
  - Active power control or re-dispatching on MV distribution grid will not be carried out only for voltage control. Indeed the management of distribution grids involves a combined optimisation process of the active and reactive powers on the grid to deal with both the power flow and

voltage constraints. Therefore active power control or re-dispatching is a flexibility service that could be offered to the DSO to solve its constraints/needs, whatever their nature are [5], [6], [7].

- **Power quality management**: this is also most often a mandatory service which depends on the technical characteristics of the technologies connected to the grid. It does not appear relevant for MAGNITUDE since it will not likely be provided through optimized synergies between energy carriers and will probably not be remunerated.
- **Minimisation of grid losses**: even if this service might be important for the reduction of grid costs, it is not needed to ensure the security of supply nor to allow the integration of RES. The grid losses are a function of the power flows and therefore depend on the location and power injections or consumptions of the grid users. MES might be able to provide such a service, but complex grid simulations will be required which isn't in scope of the MAGNITUDE project. Currently it is only implemented in some pilot projects. There is little information on the types of products that would be exchanged and in particular the associated value and remuneration.
- **System restoration**: depending on the technology involved, MES can contribute to system restoration. However, the overall value of this service for the MES might be low or at least difficult to assess since the probability of its activation is rather low. Therefore, it has lower priority than the other services of Table 2.
- **Frequency control and balancing**:
    - Fast frequency response: services with faster frequency responses than in continental Europe are currently provided in Great Britain. They are being considered in the comparative analysis of Chapter 3, along with the FCR mechanisms (Section 3.1.4.2).
    - There are presently on-going studies on new services such as ramping margin or provision of inertial response [12], [16]. However, they are not implemented yet in the case study countries. The characteristics of the products, the associated market mechanisms and remunerations still need to be clarified.

3 Comparative analysis

3.1 Electricity

In this chapter, the mechanisms for the provision of the most relevant services selected in the previous section are described and compared for the 7 case study countries. The objective is to benchmark their "variability" – or "uniformity" – between the countries in order to study later in other project Work Packages the most adequate service(s) to be provided by MES.

It should be noted that only the main characteristics of these mechanisms are considered in the present deliverable. More detailed and targeted information will be collected and described later whenever required to study the actual use cases that will be selected and defined for each case study in the other project WPs.

Although the basic needs of the electricity systems are the same across Europe, the designs of electricity markets are currently not harmonized at European level. Country specificities can indeed be found regarding the definition of the necessary products to be delivered, as well as the mechanisms to trade them (e.g. trading time, characteristics of the products, or prequalification requirements for market participation).

This design diversity is a consequence of former and/or recent particularities of each national power system: composition of the generation mix, location of demand and generation, network typology, insular or continental system, population density, development of electrified thermal end-uses, etc. Each national combination of these particularities may then amplify some power system constraints, inducing an adapted and country-specific range of mechanisms to solve them. The existing diversity is then the result of rational decisions linked to each national context.

However even if the national market designs may be different, the mechanisms for the provision of the necessary services and products generally consists of the same global framework based on the three main phases shown in Figure 2:

1. The planning and product procurement phase, including the players' optimisation process, identification of needs, formulation and submission of requests and/or bids, the market clearing or OTC negotiation, contract conclusion, etc. This phase may also require a prequalification of players to be able to participate in certain markets or to propose services.
2. The product delivery phase, including activation mechanisms depending on the service, the physical delivery of the products, possibly real-time monitoring and measurement/metering, etc.
3. The settlement or post-delivery phase, including exchanges of metered data, financial settlement, remuneration, cost recovery, possible penalties, etc.

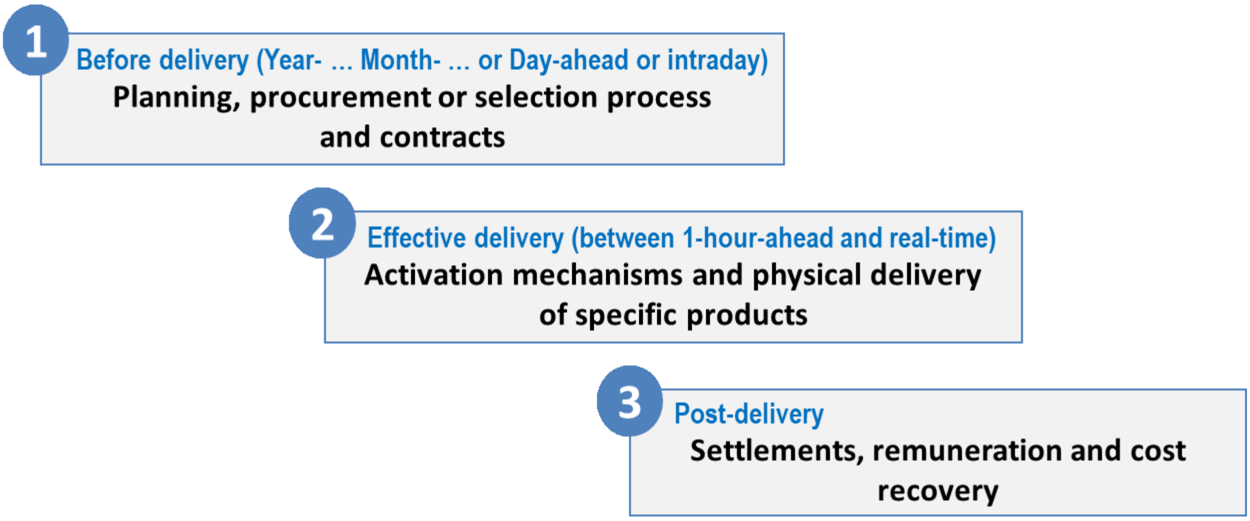

Figure 2 - Global framework of service provision mechanisms

In order to benchmark the services in the different countries, the following features have been considered and compared:

- Types of players involved and eligible technologies
- Type of participation (in particular open to aggregation or not)
- Volume thresholds (minimum and maximum volumes, minimum increment)
- Type of products and their characteristics, such as lead time, ramping or slopes, deployment or activation duration, duration between two activations, number of activations per period, and other specific features.
- Remuneration.

The detailed information and data collected on the provision mechanisms for the selected services in the seven targeted countries are provided in Appendix 7.1. The main results of the analysis and comparison that have been carried out are summarised in Sections 3.1.1 to 3.1.5 below.

3.1.1 Day-ahead energy market

The day-ahead energy trading is the trading of electricity for the following day. Day-ahead energy trades have important physical implications because of the high volumes traded.

Market participants trade on their expectations for the next day until a specific deadline every day (the gate closure). This can take place at power exchanges such as the EPEX Spot in Paris or the EXAA in Vienna. Electricity can also be traded bilaterally via OTC trading (Over-the-Counter), which concerns contracts not concluded at a power exchange.

Because of the day-ahead market coupling mechanism as an initiative of seven European power exchanges (Price Coupling of Regions or PCR used by most of the European countries[5]), the major processes for the organisation of the day-ahead energy market are already similar in the countries benchmarked (namely Austria, Denmark, France, Italy, Spain, Sweden and Great Britain), even if going further in the analysis, some country specificities can be found for instance with respect to the timelines involved, the product duration

[5] Notably Austria, Belgium, Czech Republic, Croatia, Denmark, Estonia, Finland, France, Germany, Hungary, Italy, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden and UK.

or the conditions of assets participation. In Austria, there is also a smaller power exchange called EXAA which operates in the German and Austrian day-ahead markets. The traded volumes only amount to less than 4% of the total volumes traded for Germany and Austria at the EPEX Spot.

The participation in the day-ahead energy markets is on a voluntary basis and is open to producers, suppliers, large consumers, traders and brokers. The participation of aggregators is allowed in all the case study countries, except in Italy where it is still not allowed at the moment but should be introduced in a near future. The day ahead energy market participants must be registered, and their participation is associated with the balancing obligations of Balancing Responsible Parties (BRP). More specifically, depending on the country, the market participants must either be registered as a Balancing Responsible Party themselves or be part of the portfolio of a BRP.

On the power exchanges, hourly (1 hour) products are traded for the following day. Generally, block orders for several hours may also be traded. There is also the possibility to trade half-hourly (30 min) products in Great Britain and 15-min products in Austria.

The bids are unidirectional and with a minimum volume increment of 0.1 MW both for hourly products and block orders.

The trading is anonymous. It is auction-based and takes place each day of the year. Bids are accepted until 12:00 – noon - (on the day before to the delivery day) through a merit-order principle and will receive a pay-as-clear remuneration (uniform pricing). This latter is provided for the delivered energy and generally must be comprised between -500 €/MWh and +3000 €/MWh.

The spot price is cleared hourly on the basis of the variable cost of the marginal technology, i.e. the most expensive technology necessary to match supply and demand over the concerned area (merit order). That is why spot prices are reputed to be highly variable.

Presently the most liquid market is the German/Austrian one (despite the non-participation of units which have certain types of reserve contracts such as for instance strategic reserve or network reserve). In its last report on electricity markets, the European Commission showed however that the liquidity of wholesale electricity markets slightly decreased in Germany/Austria, UK and in the Nordic markets in 2017 compared to 2016 [19]. The splitting of the German-Austrian bidding zone (effective as of 1st of October 2018) might also have an impact on the liquidity of the Austrian market. In 2017, the German/Austrian zone represented about 60% of the EPEX Spot trading volumes and the French one almost 30% [20].

More details on the characteristics of the day ahead energy markets in the case study countries can be found in Appendix 7.1.1, along with country specificities.

3.1.2 Intraday energy market

The function of the intraday energy market is to trade, on the short-term, energy volumes to be sold or purchased. Thus, in self-dispatch systems[6], the intraday energy market delivers a price signal that drives the market players to update and optimize their trading positions, reduce the volume and price risks and optimize their portfolios.

Intraday market coupling between Austria, Belgium, Denmark, Estonia, Finland, France, Germany, Latvia, Lithuania, Norway, The Netherlands, Portugal, Spain and Sweden was launched on June 13th, 2018 with 10

[6] See Section 3.1.4.1 for a definition and comparison of self-dispatch and central dispatched models.

local implementation projects (XBID project) [21]. Intraday market coupling is an important step towards the European Internal Energy Market and aims to increase the efficiency of the electricity system.

Like for the day ahead markets, the participation in the intraday energy markets is on a voluntary basis in the considered countries and is open to producers, suppliers, large consumers, traders and brokers. The participation of aggregators is allowed in all the case study countries, except in Italy where it is still not allowed at the moment but should be introduced in a near future. The intraday energy market participants must be registered, and their participation is also associated with the balancing obligations of Balancing Responsible Parties (BRP). More specifically, depending on the country, the market participants must either be registered as a Balancing Responsible Party themselves or be part of the portfolio of a BRP.

Until now, in the considered countries, the products traded are unidirectional and usually single orders (individual hourly products and depending on the country also 15-min or half-hourly products) or block orders (which can be standardised or user-defined blocks). A minimum volume increment of 0.1 MW is required, and a maximum bid volume may exist in some countries.

In Austria, Denmark, France, Sweden and Great Britain, the intraday energy market relies on continuous trading 7 days a week and 24 hours a day starting the day before the delivery day, whereas, in Italy, it is based on 7 auctions or market sessions, with some of them held the day before the delivery day and the others held on the delivery day. In Spain, the intraday energy market scheme is hybrid since June 2018: it is structured into six auction sessions in the MIBEL area (at 17:00 and 21:00 on the day before and 01:00, 04:00, 08:00, 12:00 on the delivery day) and a continuously trading European cross-border intraday market [22]. Indeed Spain is part of the XBID project mentioned above and started its trading operations in the European Cross-Border Intraday Market for electrical energy in June 2018.

Continuous trading implements a pay-as-bid matching algorithm, and therefore the energy price is paid on a pay-as-bid principle in most of the considered countries. In Italy, the intraday scheme being auction-based, the principle of pay-as-clear is applied[7]. In Spain both principles are applied: pay-as-clear in the case of auctions and pay-as-bid for continuous trading.

As for the day-ahead market, the German/Austrian intraday energy market is the most liquid one. In 2017, the trading volumes increased to 7.1 TWh [20].

The ratio between intraday traded volumes and national electricity demands significantly varies from one country to another: ACER [23] indicates that in 2016, Spain, Italy, Portugal, Great Britain and Austria/Germany kept to have the highest ratios (12% - 7%) while Nordic countries, France, the Netherlands and Belgium kept to have the lowest ones (below 2 %). If this ratio is growing in all the countries, this rise is particularly significant in Italy and Austria/Germany.

More details on the characteristics of the intraday energy markets in the case study countries can be found in Appendix 7.1.2, along with country specificities.

3.1.3 Capacity requirement mechanisms (CRM)

The EC report of the Sector Inquiry on Capacity Mechanisms [17] notes that "s*ome Member States appear to face genuine security of supply challenges, of varying magnitudes and durations, and there are specific local security of supply issues affecting certain areas within some Member States*".

[7] On the Italian intraday market (MI), "*supply offers and demand bids are selected under the same criterion as the one described for the MGP*" [i.e. day-ahead market]: "*Bids/asks are accepted after the closure of the market sitting based on the economic merit-order criterion and taking into account transmission capacity limits between zones*" [57].

A large number of power plants will be phased out in the coming years for different reasons: operational end of life, no possibility to meet new environmental standards, specific national energy policies such as for instance phasing out of nuclear energy in Germany. More generally, the ongoing energy transition combines the protection of the environment (including energy efficiency), the market liberalisation (sometimes with market failures), the integration of new technologies (storage, demand response, digitalisation …) and it radically transforms the national power systems.

As a consequence, the profitability of conventional electricity generation is presently reduced because of low wholesale market prices and lower utilisation rates, and growing share of renewable energy sources even if intermittent. In the future, the share of renewable energy is expected to keep growing and it is not clear yet whether the impacts on the electricity consumption of the emerging new end-uses of electricity (development of electric vehicles, heat pumps …) will exceed or not the impacts of strong energy efficiency measures.

In this context, the decision to maintain current capacity or to invest in new capacity appears now more complex and difficult to make.

So some European member states have decided to implement capacity requirement mechanisms in order to contribute to the security of supply, i.e. to ensure that the forecasted future generation mix in one or several years from now will indeed be able to meet the forecasted global demand plus a reserve margin to account for unexpected events, according to the targets they have defined.

For instance, in some countries, this may aim at:

- avoiding or postponing the unexpected accelerated shutdown of old conventional plants based on private owners decisions as observed in Great Britain;
- compensating prolonged outages of crucial assets as in Belgium. Indeed, the Belgian Act of 26 March 2014 has considered the strategic reserve as a temporary means "*to ensure adequate security of supply throughout the winter period each year. This system forms part of the government plan launched in 2013 to accompany the shutdowns of power stations and safeguard the security of the Belgian control area's electricity supply in the short, medium and long term*" [24]. It was for the first time constituted during the winter 2014-15. Some Belgian nuclear reactors have been taken out then restarted several times in the period 2013-2018 with huge impacts on the Belgian power market.

In the considered countries, the capacity requirement mechanisms generally imply the provision of a remuneration to capacity providers in addition to the revenues that they receive from the energy markets. They may take very different forms depending on the country:

- a decentralized capacity obligation for the suppliers in France,
- a centralized capacity market in Great Britain (and soon in Italy),
- three targeted capacity payments in Spain,
- a strategic reserve in Sweden.

They are described below.

Presently there is no capacity requirement mechanism in Austria, Denmark and Italy. However, a capacity mechanism is in preparation in Italy, and Denmark proposed to create a new 200 MW strategic reserve in its Eastern DK2 bidding zone in 2016. The reserve was intended to be transitional until interconnection capacity is increased. However, the measure has not been implemented [17].

France [25] [26] [27] [28] [29]

A decentralized capacity market is implemented in France, with a one-year ahead tender (first auction in January 2017). Required volumes are determined by the consumers or their retailers based on specifications given by the State with the TSO. Market-based prices emerge from the transactions with the capacity providers. The French mechanism is reputed to be a decentralized capacity obligation because market participants "contract" directly amongst themselves.

More specifically three types of electricity buyers, namely the retailers, large industrial consumers not supplied by a retailer and the grid operators (as buyers of the grid losses) are obliged to buy capacity certificates from capacity providers. They must buy a specific amount of certificates corresponding to their respective contribution to the peak load during the delivery period. These certificates are bought from certified capacity providers (generation, demand response, aggregators, etc.) via organised market sessions (pay-as-clear pricing), using a market platform operated by EPEX Spot, or via bilateral trades.

The certification of a provider's capacity relies on a commitment of availability during the delivery period, namely during particular winter peak periods called "PP2 periods" ("période de pointe 2" or "peak period 2"; 07h00-15h00 and 18h00-20h00 on week days nominated by RTE). Each of the PP2 days (from 10 to 25 days per delivery period) are defined and declared by the TSO the day-ahead.

If an obliged certificate buyer fails to obtain a sufficient amount of certificates for the delivery period, it has to pay a penalty. This financial settlement is calculated using two types of prices:

- when there is no risk for the system security, the settlement price is exclusively based on the market price;
- in case of risk for the system security, the settlement is based on an administered price, i.e. the maximum value that capacity can reach on the market.

Note that any contracted capacity can be checked and tested by the TSO and ex-post verification is also possible. Financial penalty applies for the capacity provider if its real capacities are less than its certified capacities.

Great Britain [30] [31] [32] [33] [34]

A centralized capacity market is implemented in Great Britain with a four-year ahead auction for both existing and new capacities (1st auction in December 2014). The participation is voluntary and is opened to different kinds of capacity providers including existing and new generation, aggregators, storage and demand response. Different contract durations are proposed for existing generation (one year), refurbishing generation (three years) and new units (fifteen years). During the delivery period, contracted capacities must answer to the TSO (National Grid - NGT) stress requests.

First step: if a system stress is anticipated (margin < 500 MW), a Capacity Market Warning signal is sent by the TSO to contracted capacity providers. This warning means that capacity providers must deliver their obligation in four hours' time if a System Stress Event is prevailing at that time in order to avoid capacity market penalties.

Second step: four hours after the warning signal is sent, a System Stress Event will occur if and only if the TSO instigates a Demand Control Instruction lasting more than 15 minutes. Each contracted capacity provider has then to deliver an Adjusted Load Following Capacity Obligation (ALFCO, in MWh) determined by the TSO. The stress event duration is at least 30 minutes. If the capacity provider fails to completely deliver its ALFCO, it will pay a penalty (equal to 1/24 of the clearing price of the delivery period; £/defaulting

MWh). If it delivers more than its ALFCO obligation, it will receive an over-delivery payment (funded by the penalties collected during the delivery period).

It should be noted that in November 2018, a judgment of the General Court of the Court of Justice of the European Union had the effect of removing the European Commission's approval of the state aid scheme for the GB Capacity Market. A standstill period has been introduced and the next auction is on hold until the scheme can be approved again[8]. Some changes are thus expected and consultations are in progress [35] [36] [37].

Italy [38] [39] [40]

The Italian CRM project in preparation is a centralized capacity market, presenting a framework similar to the British one, except that the capacity price is paid to compensate for the availability of the capacities and that the Italian mechanism includes an obligation for the power plants selected in the auctions to pay back some of the State aid when the electricity prices reach a certain level. This market-wide capacity mechanism was approved by the EC in February 2018 [41] and should be launched soon.

Spain [17] [42] [43]

Three "targeted capacity payments" are in place to send financial signals to investors[9]. They consist of prices pre-determined by the State and paid to capacity providers (the volume emerges from the market). Spain is reputed to be one of the first countries to have implemented a capacity mechanism (1997) because they have a quasi-island power system, an early massive development of renewables and decreasing load factors for gas units. That scheme was reviewed in 2007.

The three payment mechanisms consist of:

- an "availability incentive" for thermal generation (except nuclear) and hydro generation to be available during pre-defined periods. The remuneration is considered to cover their fixed standby costs;
- an "investment incentive" for conventional generating units > 50 MW (nuclear, gas, coal, hydro and oil) paid during the ten first years depending on the unit's availability during peak periods (i.e. initially if the available capacity > 90% of the installed capacity) [44];
- an "environmental incentive" scheme only for coal plants that fitted sulphur dioxide filters.

Aggregated demand response does not seem to be accepted [45].

Additionally, it is stated that "*the beneficiaries of the Spanish investment incentive are simply obliged to build and operate an eligible power plant with no additional performance requirements*" [46]. The EC finally points out that "*the current situation demonstrates there is 43% capacity margin. Instead of limiting the capacity measure to the achievement of the applicable standard, Spain has continued to pay capacity payments*" [17].

[8] The Court's judgment ruled on procedural grounds: it did not challenge the fundamental nature of the Capacity Market; it did not find it incompatible with State aid, as the British Government reminded. Potential amendments to the capacity market are being discussed (first UK Government's consultation from December 2018 to January 2019).

[9] They have replaced the power guarantee scheme in place from 1997 to 2007.

Sweden [47] [17] [48]

The Swedish strategic reserve mechanism is implemented since 2003 (Act 2003:436 on Peak Load Reserve) "*to prevent old units from being decommissioned, despite their limited economic prospects*"[10] [49]. It is opened to generation and demand response via a yearly competitive process operated by the TSO Svenska Krafnät to select providers. Selected generation capacity cannot then be bid in the energy spot market. The yearly reserve amount was initially capped at 2000 MW, with an average of 1000 MW per year. This reserve scheme was expected to end after the winter of 2019/20 but it has been finally extended until 2025 with a new cap at 750 MW as from the winter 2017/18. Demand response (including aggregated demand response) can participate but aggregated generation is not accepted [45]. The contracted capacities must be available from 16th of November to 15th of March. But their activations are rare: once in 2012/13, three times in 2009/10, five times in 2011/12; no activation in other years. These capacities were strictly taken out of energy markets until 2009. Since 2009, they can be integrated in the energy spot market under appropriate conditions to avoid any price distortion. Namely, the reserve capacity is dispatched:

- on the day-ahead energy market as a last resort, if supply bids do not meet demand;
- by the TSO after the gate closure on the balancing mechanism, if the contracted reserve capacity has not been activated and if the other bids on the balancing mechanisms are not sufficient to meet the needs [44].

The demand reduction receives an administrative payment per hour for their availability on the Regulating Power Market (RPM) and a payment for activation according to the accurate spot price. Production resources are paid fixed and variable compensations as they have set out in the tender agreement.

More details on the characteristics of capacity requirement mechanisms in France, Great Britain and Italy can be found in Appendix 7.1.3.

3.1.4 Frequency control and balancing

3.1.4.1 Generalities on the balancing mechanisms

Balancing refers to the situation after the wholesale energy markets have closed (gate closure) when the system operator (most often the TSO in Europe) acts to ensure that demand is equal to supply, in and near real time.

- Before real time (till intraday closure), commercial/financial trades on energy markets (including forward, spot and intraday ones) are done between market players: each player participating in these markets (producers, suppliers, aggregators…) must "have" a Balance Responsible Party (BRP). Namely this role can be taken up by the market player itself or be delegated to a third party BRP. A BRP is thus a market participant or its chosen representative responsible for its imbalances.
- After the gate closure of the intraday market (i.e. the energy market which is closest to real time), different balancing mechanisms (other than the energy markets) may be activated by the TSO in real

[10] The following main drivers can be given: (i) the Swedish winter peak load is strongly linked to the temperature; (ii) the Swedish hydraulic capacity widely varies from year to year; (iii) because of liberalisation, fuel plants previously used as back-up began to be decommissioned. The strategic reserve was then set up in 2003.

time (i.e. minutes and seconds before delivery) to guarantee the physical balance between generation and consumption.

- "After real time", the imbalance settlement process determines the costs to be paid by the BRP responsible for imbalances. Market players have indeed an implicit responsibility to balance the electricity system. The BRPs are financially responsible for keeping their own position (namely the sum of their injections, withdrawals and trades) balanced over a given timeframe (the imbalance settlement period). In real-time, the so-called "short" and "long" energy positions are respectively the BRPs' negative and positive imbalances. If the submitted schedules are above the metered position (deficit of generation or surplus of consumption) the market player has contributed to a deficit of electricity flowing into the system (short position). If the submitted schedules are below the metered position (deficit of consumption or surplus of generation) the market player has contributed to a surplus of electricity flowing into the system (long position). The imbalance settlement typically aims at recovering the costs of balancing the system and may include incentives for the market to reduce imbalances (with references to the wholesale market design) while transferring the financial risk of imbalances to BRPs.

As previously described, all market participants are financially responsible for imbalances they cause (directly as BRP or via a responsibility delegation to a third party BRP of their choice). However, some cases of derogation from balance responsibility are proposed for [49]:

- Demonstration projects*;*
- RES generation plants or high-efficiency cogeneration with an installed capacity lower than 500 kW (from 1 January 2026, with a capacity lower than 250 kW);
- *"Installations benefitting from support approved by the European Commission under Union State aid rules".*

There are different balancing models used by system operators. They are shown in Figure 3 and should be kept in mind to understand the wide diversity of frequency control mechanisms implemented in the Europe.

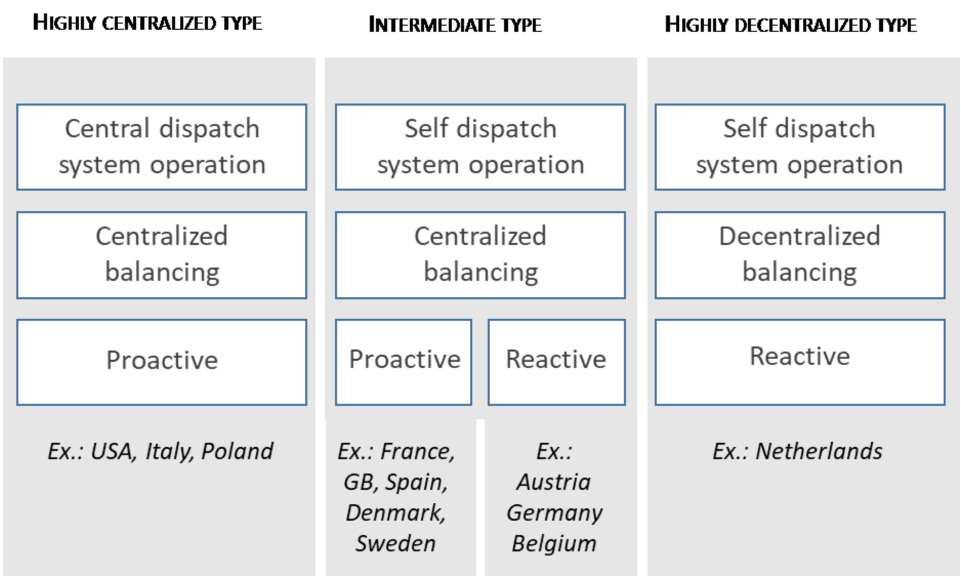

Figure 3 - Different types of balancing models (based on [50], [51], [52])

Proactive or reactive model [51]

The proactive model (France, Great Britain, Spain, Denmark, Sweden, Portugal, Norway, Finland, etc.) aims to **solve forecasted imbalances**, with the TSO able to decide to activate balancing offers before any imbalances are effectively measured. This decision is based on forecast information sent by the market players. It is a unit-based scheduling process giving TSOs very detailed forecast information. The TSO can continuously anticipate network constraints and any imbalances in the power system. Scheduling is usually mandatory for generators connected to the transmission grid. For instance in France, RTE uses a dynamic system for sizing the balancing capacity required during the course of the day called "dynamic margin monitoring", i.e. a "*low volume of reserves procured ahead of the intraday market, and supplementary balancing capacities requested only if they are strictly necessary, based on information communicated by the balancing stakeholders and predictive analysis produced by the TSO".* It relies on an obligation for generators connected to the transmission grid to offer their unused balancing resources to the balancing market[11].

The reactive model (Austria, Germany, Belgium, the Netherlands, etc.) aims to **solve imbalances in real-time**, with the TSO taking curative measures only. With this model, TSOs "*ensure that they have enough balancing capacity to balance their power systems, procuring reserves with market parties ahead of the intraday timescale (static reserve dimensioning)*".

As a consequence among others, the way to use mFRR and aFRR reserves are different. For instance, OFAEnR[12] [53] mentions the significant difference between French and German reserves: the German secondary reserve is around 2100 MW and the French one is between 500 and 1000 MW, the tertiary reserve reaches 1950 MW in France and 2500 MW in Germany. Proactive and reactive models can explain this gap: with the reactive model for instance, the TSO mainly uses automatic reserves to balance the system and thus procures a significant quantity of reserves to mitigate against all potential imbalance situations. Note also that Germany is facing a higher penetration of RES which are less predictable.

Self-dispatch or centralized dispatch [54]

"*Self-dispatching model means a scheduling and dispatching model where the generation schedules and consumption schedules as well as dispatching of power generating facilities and demand facilities are determined by the scheduling agents of those facilities"* [1]. In other words, self-dispatch, which is implemented in most of the European countries, means that the market parties (generation, consumption, storage) are responsible for scheduling and dispatching their own resources and for determining a desired dispatch position based on their own economic and physical criteria. Before real-time, generators send bids to the TSO which correspond to the self-schedules of their units. The TSO uses bids to dispatch additional generation needed to balance and secure the system in real time. As explained before imbalance charges or penalties are levied on market parties which deviate from their notified position. Closer to real time, the power system can be managed in a centralized way or in a decentralized way by the TSO. For instance in France, "*after intraday cross-zonal gate closure time, only RTE* [French TSO] *is authorized to perform operations affecting the power system's balance*" [51].

"*Central dispatching model means a scheduling and dispatching model where the generation schedules and consumption schedules as well as dispatching of power generating facilities and demand facilities, in reference to dispatchable facilities, are determined by a TSO within the integrated scheduling process*" [1].

[11] The term "balancing market" often refers to mechanisms based on tertiary reserves (mFRR and RR) but, depending on the countries, it is sometimes extended to previously-named secondary or primary reserves like in Germany [53].

[12] Office Franco-Allemand pour les Energies Renouvelables

In other words, the centralized dispatch (implemented in Italy, Greece, Hungary, Ireland & Poland) is closer to real time and the TSO is responsible for dispatching the resources once the day-ahead market is closed. Generation schedules and consumption schedules, as well as dispatching of power generating facilities and demand facilities, are determined by the TSO. This model is generally found in electrical systems where the impact of locational market imbalances is a huge threat to the system security. The TSO determines the dispatch values and issues instructions directly to resource operators. Such instructions are based on prices and technical parameters (including start-up parameters) provided by the market players. The TSO constructs a schedule for the day based on commercial and technical data from the resources, taking into account all the security constraints of the whole grid model. That also means that **in such a model, balancing, congestion management and reserve procurement are performed simultaneously in an integrated process**.

Whatever the type of dispatch it should be noted that supply-demand balance issues and network constraints are usually jointly managed (France, United Kingdom, Portugal, Spain, Denmark, Norway, Sweden, Finland, Italy…), i.e. "*an action performed for balancing purposes within the balancing market is also analysed against the impact that it has on the grid*" [51].

Particularities of the Italian case

Some national market designs are rather different from others and then more difficult to benchmark. That is the case for the Italian power system [55]. It is a proactive central dispatch power system with a centralized balancing, combined with a market-splitting scheme which defines 6 regional areas.

The Italian Power Exchange, managed by GME, is organized in several markets [56], [57]. In particular the Dispatching Services Market (**MSD,** Mercato del Servizio di Dispacciamento) (hourly prices per zone; pay-as-bid), provides the dispatching services needed by TERNA (Italian TSO) for managing and monitoring the system relief of intra-zonal congestions, creation of energy reserve, real-time balancing. As a consequence of the market splitting, MSD has a zonal configuration based on 6 market zones. It is composed of:

- The scheduling stage **(ex-ante MSD**), consisting of 6 scheduling substages, the first one on day-ahead (MSD1). The TSO accepts energy demand bids and supply offers in order to relieve residual congestions and to create reserve margins. For MSD1, there is an obligation for participating generators to send their forecasted operating programs to TERNA. TERNA can then send modified programs to generators during other sessions.
- The Balancing Market (**MB**), consisting of 6 intraday sessions (MB1, MB2, etc.). In the MB, the TSO accepts energy demand bids and supply offers in order to provide its service of secondary regulation and to balance energy injections and withdrawals into/from the grid in real time. Only offers accepted during the MSD1 are considered for MB1. New offers can be presented during MB2, MB3, MB4, MB5 and MB6, which open at 22:30 the day before delivery and close respectively at 3:00, 7:00, 11:00, 15:00 and 19:00 [57].

The following sections describe the different mechanisms in place for frequency regulation and balancing.

3.1.4.2 Frequency Containment Reserve (FCR)

The objective of the Frequency Containment Reserve (FCR) service is to provide an active power reserve activated to stop the frequency deviation and contain the frequency after the occurrence of an imbalance over the European synchronous network (e.g. in case of a frequency drop after a loss of generation).

Typically, it is required that at least 50% of the expected power variation is delivered after 15 s and 100% after 30 s but as explained below different requirements can be found depending on the country. In the same way the activation of FCR should usually be maintained at least for 15 min or 30 min depending on the country or until the restoration reserve is activated. Again, different requirements can be found depending on the country. Note that FCR is sometimes called primary (frequency control) reserve.

The FCR mechanisms in the case study countries are described in more detail below. Despite some harmonisation efforts described later, the FCR procurement and activation schemes remain partly contrasted in the considered countries, as shown in [55], [45] and national references[13]. For a better understanding, some country specificities are first explained:

- In Denmark, the power system is organised around two zones: the Western-DK1, which is synchronous with Germany and the Continental grid and the Eastern-DK2 which is coupled with the Nordic grid. In DK2 zone, there is a distinction between two types of FCR: FCR-N (specific Nordic product with N for normal operating band within 49.90 Hz < f < 50.10 Hz), and FCR-D (with D for "disturbances" for larger frequency deviations below 49.90 Hz).
- In Sweden, there is also a distinction between the same two types of FCR as in DK2 zone, namely FCR-N (specific Nordic product with N for normal operating band within 49.90 Hz < f < 50.10 Hz), and FCR-D (with D for "disturbances" for larger frequency deviations below 49.90 Hz). It is also noted that "*The fact that the market is designed so specifically for hydro power makes it difficult for the owners of other sources to enter this market*" [58].
- Great-Britain, as an island facing particular system constraints, has several mechanisms for the primary reserve:
    - The Firm Frequency Response (FFR), with a full response in 10 s (primary) to 30 s (secondary).
    - Enhanced Frequency Response (EFR), designed in 2016 as a specific faster reserve within 1 s.
    - Mandatory Frequency Reserve (MFR) which consists of a primary reserve, a secondary reserve and a high frequency reserve. MFR completes the firm volume of the EFR. Its volume is increasing and volatile, based on flexible generation available in the balancing market closer to real time than FFR (month).

  Additionally, even if there is one Electricity System Operator (National Grid ESO) for the whole Great-Britain[14], there are several regional TSOs and the above FCR mechanisms can be affected by this situation. For instance, the capacity thresholds specified in the connection agreement for participation in MFR are different for National Grid (small: < 50 MW, medium: 50-100 MW, and large: > 100 MW), Scottish Power (small: < 30 MW, large: > 30 MW) and Scottish Hydro Electricity (small: < 10 MW, large: > 10 MW) (see Appendix 7.1.4 for more details).

  In June 2017, the British TSO National Grid announced its intention to revamp the balancing and ancillary services and published a product roadmap for frequency response and reserve services in December 2017 [59]. The FFR weekly auction trial starting in June 2019 is a first consequence. In December 2018, National Grid was still "*investigating what a new, faster-acting frequency response product may look like, and how it could form part of a new suite of frequency response products*" [60];

[13] National information mentioned in this section and detailed in Table 22 of Appendix 7.1.4 are taken from [197] [198] [201] [202] [212] [211] [199] [203] [204] [213] [200] [197] [196] [205] [206] [207]. See also ENTSO-E website on Requirements for Generators (RfG) [244], on Demand Connection Code (DCC) [245] and on High Voltage Direct Current Connections (HVDC) [246].

[14] The Electricity System Operator (ESO) will become in April 2019 a separate company within the National Grid Group. However activities of the ESO and Electricity Transmission (ET) have started to be separated since autumn 2018.

this investigation particularly concerns the EFR evolution. "*These new services will […] have an impact on future volumes bought through the MFR and FFR markets*" [61].

Participation in the national FCR mechanisms can be voluntary (Austria, Denmark, Sweden) or mandatory (France and Italy for generation, Spain and Great Britain). Different thresholds can be imposed, for instance in France, the participation is mandatory for new generation > 40 MW and existing generation > 120 MW but it is voluntary for other providers provided they are certified; in Italy, the participation is mandatory for generators > 10 MW. In Great Britain, as mentioned above, the mandatory participation in the MFR depends on the size and location of the power plant.

Aggregation of demand response and generation is allowed excepted in Italy and Spain [45].

Although most mechanisms are based on tendering processes, their periodicity remain different: daily auctions in Denmark; weekly tendering process in Austria and France, monthly in Italy and Great Britain (for the FFR).
In Great Britain, as mentioned above, in the context of the evolution of balancing and ancillary services, an FFR auction trial will start in June 2019 over a period of 24 months. This change for a closer-to-real-time procurement is expected to create new opportunities for wind and solar producers: it will be easier for them to forecast their availability with sufficient certainty to participate in weekly tenders rather than the existing monthly ones. Some MFR volume will also be introduced into the FFR Auction trial [60].

The FCR product is generally symmetrical (except in Denmark where this is not necessary) and the minimal volume of the offers varies from 0.1 MW in Sweden to 1 MW in Austria, France and Great Britain.

The obligations in terms of response times are different in the different case study countries and can be summarized as follows:

- Austria and France: in case of frequency deviation > 200 mHz, 50% of the expected power variation must be delivered in 15 s and 100% within 30 s.
- Italy: in case of frequency deviation between 100 and 200 mHz, 50% within 15 s and 100% within 50 s.
- Denmark: in the DK1 zone, 100% within 30 s. In the DK2 zone, there are two cases: for the FCR-N, 100% within 150 s; for the FCR-D, 50% within 5 s and 100% within 30 s.
- Sweden: for the FCR-N, 63% within 60 s and 100% within 3 min; for the FCR-D, 50% within 5 s and 100% within 30 s;
- Great Britain: MFR and FFR mechanisms impose three types of response times: within 10 s for their primary response, within 30 s for their secondary response and within 10 s for the high frequency Reserve. EFR imposes an even faster response: delivery within 1 s of 100% of an active power output proportionate to the frequency deviation.

The delivery of the product should usually be maintained for a duration between 15 minutes and 30 minutes, except in Great Britain where the primary upward response of MFR and FFR should be sustained for 20 s and the downward response (high frequency) should be able to be sustained indefinitely.

The FCR remuneration is mainly based on a pay-as-bid approach excepted in Italy and in Spain (no remuneration or under certain conditions).

It should be noted that in the European synchronous grid area, FCR mechanisms in Germany, Netherlands, Belgium, Switzerland, France and Austria[15] participate in the same weekly cross-border merit order-based tendering process.

This homogenisation of FCR services procurement is expected to be amplified in the following years. Several pilot initiatives have been launched to support the implementation of the EC Guideline on Electricity Balancing [1].

The initiative **FCR Cooperation** launched by several TSOs – currently 50Herz, Amprion, APG, ELIA, ENERGINET, Swissgrid, TENNET, RTE and Transnet[16] – aims at having the FCR procurement process converge in the associated countries based on a TSO-TSO model [62], with the following characteristics:

- Each FCR provider submits its offers to its own national TSO (i.e. the TSO of the grid it is connected to); then the national TSOs mix the bids collected for their national zone with the ones of the other TSOs.
- Participants submit weekly symmetric (up and down) reserve products, namely a volume of primary reserve over a given delivery period from Monday 0h00 to Sunday 24h00 (168 hrs), with a minimum bid size of 1 MW.
- The bid submission period is from Friday 12h00 on week W-2 to Tuesday 15h00 on week W-1, and final results are published on www.regelleistung.net before Tuesday 16h00 on week W-1.
- Bids are selected via a merit order. They are totally rejected, totally accepted or partly accepted by increments of 1 MW depending on their prices in comparison with the maximum price of the last bid retained. In case of cross border constraints (imports/exports), some bids with prices below the auction price can be rejected.
- The remuneration is pay-as-bid-based.

The discussions regarding the possible evolution of the FCR Cooperation are on-going since 2017 [62]. Concerned TSOs have already decided to change some key elements, with an implementation taking into account the EC Guideline on Electricity Balancing (EBGL) calendar. On 26 April 2018, the TSOs submitted proposals to the national regulatory authorities [63] [64] [65], which, in turn, submitted, at end of September 2018, two requests to amend these proposals[17]. The following evolutions are expected to be deployed:

- Change from weekly product duration to one-day product duration as from July 2019 then to 4-hour product duration as from July 2020 (i.e. 6 independent products in a day).
- As from July 2019, change from weekly auctions to daily auctions on working days only with D-2 gate closure time and daily products, then as from July 2020 daily auctions all days with D-1 gate closure time and 4-hour products.
- No introduction of asymmetric bids.
- Introduction of indivisible bids but with a maximum bid size of 25 MW, with a restriction that no divisible bid can be paradoxically rejected.
- Maintenance of the minimum bid size at 1MW with a bid resolution of 1 MW.
- As from July 2019, change from a pay-as-bid remuneration for each awarded bid to a pay-as-clear settlement, with the determination of a marginal price for each country.

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15 And maybe Denmark soon.

16 Participation of Western Denmark is foreseen

17 Namely: (i) to move the first implementation step from 26 November 2018 to 1 July 2019 (delivery day); (ii) to change the date from 26 November 2018 to 1 July 2019 for the exemption from the obligation to allow balancing service providers to transfer their obligations to provide balancing capacity.

More details on the characteristics of the FCR provision mechanisms in the case study countries can be found in Appendix 7.1.4, along with country specificities.

3.1.4.3 Automatic Frequency Restoration Reserve (aFRR)

The objective of the Automatic Frequency Restoration Reserve (aFRR) service is to provide an active power reserve which is automatically activated to replace the FCR after a frequency deviation and to restore the frequency to its nominal value. The required full activation time varies from 5 minutes (and even less in the UK) to 15 minutes depending on the country. In the same way, depending on the country, the requirement on the deployment duration (or how long aFRR activation should be maintained) varies from no time limit down to 2 hours or even less, namely until the manual restoration reserve (mFRR) is activated. Note that aFRR was formerly and is sometimes still called secondary frequency control or reserve.

Like for the FCR, aFRR mechanisms still show significant differences throughout the European Union, in particular due to the different generation structures from one country to the other, as shown notably by ENTSO-E [55] [66], SEDC [45] and national references[18].

The aFRR mechanisms in the case study countries are described in more detail below. But, for a better understanding, some general considerations have to be explained first.

- aFRR is applied in two main synchronous areas in Europe (Continental and Nordic), which present several differences as detailed by ENTSO-E [66], and as reflected in the implementation of frequency regulation mechanisms. For instance, there are many Load-Frequency Control (LFC) blocks in the continental area and only one LFC block in the Nordic one (Denmark-East, Finland, Norway & Sweden). Each LFC block has its own Load-Frequency Controller. The Load Frequency Controller is (physically) a process computer implemented in the TSOs' control centre systems. This computer provides the automated instructions to aFRR providers that are connected to the Load Frequency Controller by appropriate telecommunication connections.
- aFRR is not explicitly used in Great Britain [55]. But the two British FCR mechanisms respectively named MFR (Mandatory frequency reserve) and FFR (Firm frequency response) are composed of primary and secondary responses and may overlap with aFRR. They are described in the previous FCR section.
- aFRR is sized by the TSO in charge of a given geographical area. Each TSO is then free to fix the repartition between aFRR and mFRR (manual Frequency Restoration Reserve described in the next section). As a consequence, the way to use the aFRR to balance a national system significantly varies from one country to another. According to estimates of ENTSO-E [66] on the share of the activated aFRR balancing energy compared to mFRR and RR, in 2015, this ratio was below 20% in Denmark and Sweden, between 20-40 % in Italy and Spain, between 40-60 % in France and beyond 80 % in Austria.

The participation to the aFRR scheme is voluntary in Austria, Denmark and Spain, and it is mandatory in France for generating units larger than 120 MW and in Italy. Aggregation of loads and generation is

[18] National information mentioned in this section and detailed in Table 23 in Appendix 7.1.5 are taken from the following sources: [213] [199] [198] [67] [217] [215] [204] [201] [214] [216] [207]. See also ENTSO-E websites on Requirements for Generators (RfG) [244], on Demand Connection Code (DCC) [245] and on High Voltage Direct Current Connections (HVDC) [246]

accepted in Austria, Denmark, France (if connected to the transmission) and in Sweden, but not yet in Italy and in Spain [45].

The minimum authorized offers vary from 1 MW (Denmark, France) to 5 MW (Austria, Sweden).

The product resolution in time (i.e. for which the product can be bid into the market) varies from hourly resolution in France, Italy, Spain and Sweden to weekly in Austria then to yearly in Denmark. Data for the Italian case is not available (ENTSO-E [55]).

The gate closure time widely varies from a week ahead in Austria to a day ahead in France, Denmark, Italy and Spain.

There are two types of activation in place [66]:

- a merit order activation in Austria, based on an ascending ranking of the marginal costs of aFRR bids and selecting the cheapest ones;
- a pro-rata activation of all proposed aFRR bids in France, Spain, Italy, Denmark and Sweden: "*the requested aFRR is distributed pro-rata to the aFRR providers connected to the LF Controller*".

The requested Full Activation Time (FAT) varies from one country to the other: Austria < 5min, Italy < 5min, Spain and Sweden < 120s, 400s in France. In the case of Denmark, there are in fact two different FATs: < 5min in the DK2 zone and < 15 min in the DK1 zone [67]. The deployment duration seems to vary from at least 15 min in Spain to no-limit duration in France and Austria.

Different schemes to remunerate aFFR are used: pay-as-bid remuneration (Austria, Italy and Sweden) or pay-as-clear remuneration (Spain) for both reservation and activation, or different specific remuneration schemes for reservation and activation, involving sometimes regulated prices (France) (see Appendix 7.1.5 for more details).

Like for FCR, harmonization will be needed to implement a common aFRR market in accordance with the EU Guideline on Electricity Balancing (EBGL) [1]. This harmonization is in particular the objective of the **PICASSO Project** [68] (**P**latform for the International **C**oordination of **A**utomated Frequency Restoration and **S**table **S**ystem **O**peration). More specifically, eight TSOs from five countries (APG, Elia, TenneT NL, RTE, 50Hertz, Amprion, TenneT DE and TransnetBW) took the initiative in 2017 to anticipate the timelines set forth by the EU Guideline on Electricity Balancing [1] by establishing the PICASSO project and starting the work on the design of an aFRR platform to facilitate future European-wide discussions. Since then, several other European TSOs have progressively joined the cooperation. In December 2018, the project consisted of twenty two TSO members, and four observers. Note that PICASSO follows the project EXPLORE (European X-border Project for LOng term Real-time balancing Electricity market design) launched by the TSOs of four countries: Austria, Belgium, Germany and the Netherlands.

The main targets of the PICASSO project are:

- Design, implementation and operation of an aFRR platform compliant with the approved versions of the EU Guidelines on Electricity Balancing (EBGL), on the system operations (SOGL) [69] and on the Capacity Allocation and Congestion Management (CACM) [70], as well as other regulations.
- Enhancing economic and technical efficiency within the limits of system security.
- Integrating the European aFRR markets while respecting the TSO-TSO model.

PICASSO was in its phase 1 with a first consultation at the end of 2017. A second consultation was opened in April 2018 and closed in June 2018 [68]. It has adopted a stepwise approach to define a minimum level of harmonization [71]. An explanatory document was published in November 2018 by all the TSOs to describe their proposal [72]. Some examples of proposed evolutions are: no harmonization of full activation time (FAT) at go-live of the platform until 18 December 2025, then an harmonized FAT of 5 minutes; minimum bid size equal to 1 MW, with a bid granularity of 1 MW (maximum bid size of 9999 MW), etc.

Without any request for amendments by the national regulatory authorities and by the Agency for the Cooperation of Energy Regulators (ACER), the approval is due 6 months after the delivery of the TSOs' proposal to the national regulatory authorities. In accordance to Article 21(6) of the EBGL, all TSOs performing an automatic frequency restoration process should then be connected to the aFRR-Platform no later than 30 months after the approval, i.e. before December 2021.

More details on the characteristics of the aFRR provision mechanisms in the case study countries (except Great Britain where it is not used – see above) can be found in Appendix 7.1.5, along with country specificities.

3.1.4.4 Balancing, manual Frequency Restoration reserve (mFRR) and Replacement Reserve (RR)

The objective of the Manual Frequency Restoration Reserve (mFRR) service is to provide an active power reserve which is manually activated after a frequency deviation to complement or to release the aFRR if the demand for secondary control reserve is too high. As shown below and in the appendix, there is currently a high diversity of mechanisms for mFRR provision in Europe. Most of the time the mFRR activation shall be done within 15 min but, in some countries, it might be less (e.g. between 10 to 13 min). The deployment duration is in the order of hours, e.g. at least 1.5 or 2 hours, or may be fixed by contract.

The objective of the Replacement Reserve (RR) service is to provide an active power reserve which is manually activated to progressively restore the activated FRR (aFRR and mFRR) and/or support FRR activation. The provision mechanism of RR is very different from country to country. In some countries, RR does not exist, in others they are procured through the intraday energy market or there might be a dedicated provision mechanism. The RR activation time (when RR provision exists) is generally longer than the FRR one, e.g. 30 min or more.

mFRR and RR were formerly and are still sometimes called tertiary frequency control or reserve.

Finally, there might also be some other specific balancing mechanisms in some countries closely linked to the tertiary reserve. For instance in France, an EDA[19] approved for mFRR and the “Réserve complémentaire” (“Complementary Reserve”) must be previously approved as an adjustment entity (balancing entity) and when a bid is retained as a RR capacity, it must be submitted on the so-called balancing market.

Eligible participants have to be pre-qualified and to meet technical requirements in all countries. But currently, the national designs for balancing and mFRR within Europe are highly diverse[20] [21].

The providers allowed (or obliged) to participate in the markets are generators, loads, storage, but specificities may apply depending on the country, for instance:

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[19] EDA: elementary unit able to respond to the TSO's solicitations by injecting or withdrawing a quantity of electricity asked by the TSO over a given period, beyond or below the quantity forecasted by the operating program of the contributing units [251]

[20] National information mentioned in this section and detailed in Table 24 in Appendix 7.1.6 are taken from the following sources: [204] [203] [51] [219] [74] [220] [51] [206] [198] [218] [221] [206] [207] [250] [223] [222]. See also ENTSO-E websites on Requirements for Generators (RfG) [244], on Demand Connection Code (DCC) [245] and on High Voltage Direct Current Connections (HVDC) [246]

[21] See for instance, Mathieu [53] comparing the French and German systems.

- In Italy, providers are generators connected to the transmission grid and "non-predictable" renewables are not eligible.
- Storage units are eligible in the Austrian, Spanish or British markets but cannot participate in the Danish or Swedish ones.
- Aggregation of loads and aggregation of generation is generally allowed, except in Italy where it is not accepted, but some conditions may also apply in some countries for very specific mechanisms (see Table 24 in Appendix 7.1.6).

As mentioned above the manual Frequency Restoration Reserve (mFRR) is characterized by a manual activation. Products traded are bidirectional (asymmetrical), e.g. allowing for a decrease or increase of power. With some very few exceptions, the mFRR shall be fully activated within 10-15 minutes. The British case however has different ramping times: 2 minutes for the Fast Reserve, 20 minutes for Short-Term Operating Reserve (STOR), 89 minutes for the Balancing Mechanism Units (BMU) in hot standby, etc.

The minimum offer ranges from 1 MW in Austria (for the first bid; 5 MW for the other bids), to more than 10 MW in France or Sweden, and even 50 MW currently for the British Fast Reserve (but it will be reduced to 25 MW as from April 2019) [60]. Some mechanisms propose intermediate thresholds (3 MW for the British STOR; 5 MW in Denmark). Additionally, in France, a derogatory regime allows, as of January 2018, some small units to supply offers between 1 MW and 10 MW under certain conditions [73] [74].

Deployment duration (or sustained activation) also varies: 15 min in Great Britain for Fast Reserve; different maximum durations in France (30, 60, 90 and even 120 min), at least 2 hours in Spain, Sweden and Great Britain (for STOR), several hours in Denmark, unlimited duration in Italy and contracted duration in Austria.

The modes of selection present the greatest diversity: depending on the service (mFRR, RR or balancing) and on the country, from daily tenders to yearly auctions, but also weekly and monthly processes, and even three tenders per year for STOR.

The mechanism of remuneration also varies according to the country between pay-as-bid and pay-as-clear.

Finally, some mechanisms are not so easy to include in a category. That is particularly the case in Great Britain, with the implementation of several specific mechanisms to provide the tertiary reserve: Fast Reserve, Short Term Operating Reserve, Balancing Mechanism and Demand-turn Up. Fast Reserve is described in this section, even with an active power delivery within two minutes and a sustained activation of 15 min. But NGT website describes it as a "*reserve service*" rather than a "frequency service" and [45] mentions Fast Reserve as a manual FRR. Furthermore, some countries like Italy do not distinguish between mFRR and RR or do not have a dedicated replacement reserve.

To address these large differences between mFRR and RR mechanisms in the European countries, common projects have been launched by TSOs:

MARI project (mFRR): most of the EU TSOs are involved in the MARI initiative (Manually Activated Reserves Initiative) [75] [76] [77] [78]. They started working on the principles of a mFRR platform in 2016, in line with the article 20(1) of the EBGL on 07/09/2017. The platform considers two types of bids according to their activation: direct or scheduled activation. The implementation of the platform is expected within 2022. A proposal called "mFRRIF" was presented by all the TSOs in December 2018 [79], [80]. It proposes, for instance, the following characteristics for each standard mFRR balancing energy product bid: FAT of 12,5 minutes; minimum bid size of 1 MW, with a bid granularity of 1 MW (maximum bid size of 9999 MW); minimum duration of delivery period equal to 5 minutes, etc.

TERRE project (RR): the TERRE project (Trans European Replacement Reserves Exchange) is the pilot project for the RR-Platform necessary to organize the coordinated exchange of RR balancing energy between TSOs as requested by the EBGL [81] [82] [83] . Its design phase started at the end of 2013. The first consultation process started on March 7th, 2016. The TERRE project aims to establish the main market functioning of the IT platform (called LIBRA) by end 2019 as requested by the EBGL. TSOs currently participating in the TERRE project and the RRIF (Replacement Reserve Implementation Framework) are: National Grid, Swissgrid, REE, REN, MAVIR, TERNA, Transelectrica, RTE, CEPS and PSE, along with several observers including ENTSO-E. TERRE will permit to optimize the allocation of RR and to cover the TSOs' RR balancing energy needs. The project started with the harmonization of the main principles instead of a full harmonization from the beginning. The model for the exchange considered in TERRE is the TSO-TSO model. Some criteria to describe the cross-border products have been identified as having a medium or high harmonization priority.

The TERRE project is the most advanced project which implements such a European platform. In December 2018, the relevant national regulatory authorities approved the RRIF submitted in June 2018 [84] in which the principles of the market design are explained. Several bid formats are proposed: divisible and indivisible bids for several delivery periods ([H, H+15min] or [H+15min, H+30min] or [H+30,H+45] or [H+45min,H+60min]); upward or downward direction; possibility of linked bids in time, exclusive bids in volume or exclusive bids in time; etc.

Potential impacts on national systems will not be similar in all countries but will depend on each initial national framework. Two examples are given in [81]:

- In Italy, Terna currently makes no distinction between Replacement Reserve and mFRR. A clear distinction between these two products will then be introduced in the Italian network code.
- In Great Britain, "*the GB electricity market currently uses a variety of bespoke ancillary services and products in order to balance the system. Notably a great deal of balancing is done through directly activating offers via the Balancing Mechanism. Therefore, Replacement Reserves (and the other standard products defined in the European Guidelines) are not easily mapped across to existing GB products. The introduction of the standardised products will be a big change in itself*".

More details on the characteristics of the balancing, mFRR and RR provision mechanisms in the case study countries can be found in Appendix 7.1.6, along with country specificities.

3.1.5 Elements on congestion management

As previously explained, a congestion appears as soon as the forecasted or real power flows exceed the physical capability of the grid components (cables, transformers …). This can occur on the transmission grid, the distribution grid or even on the interconnections between countries or transmission systems. The system operator (TSO or DSO depending on the case) has then to take measures to manage this situation and relieve the associated constraint. Congestions also need to be considered for N-1 situations, namely when a contingency occurs on the grid.

With the increased penetration of renewables, congestion management both on transmission and distribution networks will become more important.

Congestion management is by nature a complex issue since there are many means to solve it. The use and efficiency of a specific means to solve congestion management will depend on the considered grid segment (transmission, distribution, and interconnection) and on the type of constraints affecting the (national or local) grid, as well as on its overall state.

Congestion management is also facing new challenges. For instance, as reminded by Haque [4], the distribution networks worldwide have been hosting an increasing share of distributed RES and new forms of load consumption (electric vehicles, heat pumps, electrical heating ventilation and air-conditioning systems). The impacts of new end-usages could be more or less important in terms of energy but their impacts in terms of capacities (or instantaneous power) could be more problematic for the local grid. These new flow patterns have exposed three potential weaknesses for congestion management [11]:

1. risk of inefficiencies within countries with potential gaming opportunities (where competition is poorly supervised) and inefficient dispatch,
2. risk of inefficiencies between countries if the scheduling of cross-border flows is treated separately from domestic dispatch,
3. risk of inefficiencies in dynamic management if the allocation of internal transmission capacity is determined long before real time and closer-to-real-time abilities of the power system to flexibly deliver power and ancillary services are not sufficiently coordinated.

There is a very large diversity of approaches used in the different countries to manage congestions on the transmission and distribution networks and it is often very difficult to get detailed information on the different schemes. Therefore, without being exhaustive, only several options are discussed below for the System Operator (SO) to manage grid congestions depending on whether a congestion risk can be anticipated or prevented [4] [85]. Two main categories of approaches implementing in particular active or reactive power control are distinguished: direct control of different types of resources on the grid and use of market-based approaches.

1. The SO can directly control different types of resources for instance:

- Modify temporarily the grid configuration and topology in order to reduce the coefficient of load transfer from one line to another (changing the status of the normal-open or normal-close contacts) and/or use the technical means at its disposal such as transformer taps/phase shifters, FACTS (flexible alternating current transmission system - referring to a combination of power electronics components with traditional power system components). Such technical means are totally under the SO’s control in order to secure the grid,
- Use reactive power control,
- Curtail RES with or without financial compensation (if consistent with the EU objectives to integrate renewables),
- Or more generally, use direct active power control in case of large incidents. However, this can induce costs or discomfort to the customers, sometimes with financial compensations imposed by the regulator.
- In a longer term, reinforce the constrained part of the grid, if the congestion problem is recurring or expected to occur regularly in the future.

2. The SO can use market-based approaches involving in particular the procurement of flexibility services:

- Flexibility services can be procured by the SO for **the re-dispatching** process, which consists in modifying (up/down) the generation patterns (or load patterns) after the energy market gate closure in order to change physical flows in the system to prevent grid constraints or relieve a physical congestion (ACER & ENTSO-E [86]). This generally implies the modification of the generation programs (or load programs) of producers (or consumers) well located on the network.

- On the transmission system TSOs often procure those flexibility services from well-located producers or consumers via the balancing mechanism but dedicated mechanisms may also be put in place. On the other hand a balancing offer which might create or amplify a risk of congestion can be partly or totally excluded (or disqualified) from the economic precedence of balancing during the hours of the congestion occurrence. This anticipation means that the re-dispatch is pre-defined. Re-dispatching can be distinguished in three categories: internal re-dispatching carried out in the bidding zone constrained by the congestion, external re-dispatching performed fully in another bidding zone than the one where the congestion occurs, and cross-border re-dispatching carried out in different bidding zones.
- If re-dispatching has been used by TSOs for a long time, at the distribution level, this would imply that the DSOs procure flexibility services from the energy resources connected to their grid. This can be done either directly through calls for tenders or OTC mechanisms, which allow the DSOs to set contracts with producers or consumers in order to guarantee the availability of power capacities on the distribution grids that can be used or activated when needed. This could also be achieved through flexibility markets organised at the distribution level. Presently in most countries, the appropriate regulation is not in place yet to allow DSOs to procure such services in a market-based approach [87] and such procurement is generally limited to pilot projects. However, market-based approaches are expected to further develop in the future[22]. In particular at distribution level new potential flexibility services can be procured from customers and demand-response [85].
- Additionally, on radial MV distribution grids re-dispatching can be used not only to manage the power flows but also to solve voltage constraints. Indeed, due to the technical characteristics of the MV lines, active and reactive powers are much more "coupled" on the distribution networks than on the transmission networks. Therefore, modifications of the active power of well-located producers or consumers can be used to control the voltage and it appears as an efficient means to do so (e.g. see [5], [6], [7]). Re-dispatching for the control of the voltage on distribution network is therefore another flexibility service that should be considered for the provision by MES.

- RES curtailment through a market-based approach consistent with the EU objective to integrate renewables. The "Clean Energy Package for all" proposals of November 2016 might redefine priority access for renewables and clarify the framework for curtailment (no discrimination, financial compensation). As explained by the EU Briefing on the internal market for electricity [88], "*priority dispatch for renewables and high-efficiency cogeneration, introduced by the Renewable Energy Directive (2009/28/EC) and the Energy Efficiency Directive (2012/27/EU), would be limited to small installations below 500 kW (below 250 kW from 2026), demonstration projects and existing installations that already benefit from priority dispatch. The rules for curtailment and re-dispatch should be based on objective, transparent and non-discriminatory criteria. Self-generated electricity would not be curtailed except in emergencies*".

[22] EU Clean Energy Package article 32.1 stipulates: "*Member States shall provide the necessary regulatory framework to allow and incentivise distribution system operators to procure services in order to improve efficiencies in the operation and development of the distribution system, including local congestion management*"

- TSO can use countertrading, which is defined by ACER & ENTSO-E [86] as a "*Cross zonal energy exchange initiated by system operators between two bidding zones to relieve a physical congestion. The precise generation or load pattern alteration is not pre-defined*". In other words, this a global cross-border trade made between two TSOs in the opposite direction of the constraining flow.
- Price signals can also be used, for instance: day-ahead dynamic grid tariffs [89], locational marginal pricing or nodal pricing where central dispatch applies, like for instance in six regions in the USA, market to allocate capacities such as the Net Transfer Capabilities NTC for interconnection in Europe.

Other types of distinctions between the different means to manage congestion can be found in the literature namely:

- Chidambararaj [90] distinguishes between cost free means (out-aging of congested lines, operation of transformer taps/phase shifters, operation of FACTS devices) and non-cost free means (re-dispatching power generation; load curtailment and use of (non-cost free) load interruption options).
- Going further in the analysis, Hadush [87] "*categorizes congestion management approaches with respect to different states of a power grid system operation, while explicitly capturing the interaction between market and grid operations under each system state*". To simplify, he focuses on three main congestion management approaches corresponding to different system states: congestion pricing approach, re-dispatching and curtailment.

Anyway, a deeper cooperation between TSOs is needed to optimize the electricity system with increased RES. To improve the cooperation between TSOs in terms of congestion management, the Network Code on Capacity Allocation and Congestion Management (CACM) [70] strongly advocates more coordinated remedial actions, in particular for cross-border relevance (sharing dispatch information …).

In the same way, a deeper cooperation between TSOs and DSOs also appears as a key-point. Different solutions to improve the DSO-TSO cooperation have been proposed and tested: for instance the 'Traffic light' concept in Germany sending signals (Green, Amber/Yellow or Red) to the market players to take into account the distribution grid state and possible congestions (Smart Grid Task Force 2015) [87], different models of DSO-TSO coordination in demonstrations and pilots carried out in European projects such as EVOLVDSO, SMARTNET, etc. More generally, this TSO-DSO coordination issue is presently the subject of a lot of projects, international working groups and other initiatives (see for example [91], [92], [93], [94], [95]).

Unlike for day ahead and intraday energy markets or even frequency regulation mechanisms, it is often very difficult to get detailed information on the procurement of services by systems operators for congestion management. That's why in the following paragraphs, only examples of congestion management mechanisms in some of the case study countries are presented. More detailed and targeted information will be collected and described later in other WPs for the case study countries where the specific use cases involving congestion management will be studied. Mechanisms being developed in other H2020 European projects might also be considered in these use cases, in particular regarding potential future congestion management services to DSOs.

3.1.5.1 Austria

In Austria, there is a close cooperation between APG (Austrian TSO) and the TSOs of neighbouring countries (TSO security cooperation) [96]. An important reason for the activation of re-dispatching measures in

Austria (mostly increase of production plans of Austrian power plants) is related to network bottlenecks between Southern and Northern Germany, mainly during the winter seasons, but there are also strategic network bottlenecks between Western and Eastern Austria which can cause APG to request Austria-internal re-dispatching, mainly during the summer season. [97] [98].

Bilateral service provision contracts are established between APG and producers, or there might be a mandatory service in case that network security is endangered.

In Austria, some power plants that are out of the market for economic reasons are contracted as a strategic network reserve. Power plants that are part of the electricity market are also contracted or may be called in addition during critical situations [99].

Symmetrical products are contracted with power plants located on either side of an expected network congestion, or in another words, an increase in the generation plan of power plants located on one side of an expected network congestion and an exactly proportionate decrease in the generation plan of plants located on the other side of the expected network congestion are requested simultaneously from at least two power plant operators.

3.1.5.2 Denmark

Energinet combines the bids of the BRPs in a single merit order curve, from which it can activate the regulating power in order to secure the physical balance of the power system and to relieve network congestions. Special regulation is applied, when Energinet selects specific regulating power bids for upward and/or downward regulation disregarding the merit order list. This may occur either as a con- sequence of bottlenecks/restrictions in Energinet's or neighboring areas' grid. The instructions for the common Nordic Regulating Power Market[23] specify that bids used for network reasons such as congestions, should not affect the Nordic imbalance prices. The instruction further states that the bids should be used for balancing purposes first and foremost, however, unused bids can be used for special regulation, i.e. mitigation of congestion, and these bids are settled according to pay-as-bid [100].

Regarding interconnections with neighboring areas, Western Denmark and Eastern Denmark experience two different situations. Western Denmark has a larger capacity in terms of interconnections with neighboring areas than Eastern Denmark. There is a Joint Declaration between Germany and Denmark which aims that «*the cross-border electricity trade capacity available for the market shall be increased in a stepwise approach*». Currently both TSOs are using existing measures to secure the necessary amounts of countertrade.

3.1.5.3 France

Network congestion is not a major problem in France and is in fact decreasing. The costs of internal congestions are relatively low: 5.6 M€ in 2014 on the balancing market for the objective "congestions" (see below) and a total cost of 30 M€ in 2012. This might be a consequence of the new investment plans to avoid congestion issues and of the grid connection policy: generators have to queue and wait until there is sufficient transmission capacity in the area where they want to be connected to the grid before they receive the authorisation to proceed.

Congestion management is based on the anticipation of the potential loss of a key asset in the grid (i.e. non-compliance with the "N-1" rule): for instance if the system loses a line, it could be exposed to a risk. RTE,

[23] Denmark, Sweden, Norway and Finland are part of this common Regulating Power Market.

the French TSO, has a forecasting approach to prevent such risk: (i) it carries out its own forecasting studies; (ii) it compares the results with the programs sent in day-ahead by producers, large consumers and aggregators if a risk is anticipated. Beside direct control by the TSO to modify the topology of the grid, one of the main congestion management mechanisms in France is the procurement of services through the balancing market: "*the power generating units connected to the transmission grid have a legal obligation to offer their unused balancing resources on the balancing market. This obligation is an integral part of the scheduling process […]. It in no way prevents generators from trading on the market: stakeholders are simply required to provide TSOs with what they have not sold on the markets. This information is regularly updated based on the trades executed on the markets*" (RTE [51]). RTE can also use the bids of large consumers on the balancing market. RTE can then select the cheapest offers among the ones able to solve its "local" problem and in such a way modify (up/down) the generation programs and/or loads of well-chosen producers and large consumers. Market participants receive a pay-as-bid remuneration. Additionally, a balancing offer likely to create or to amplify a risk of congestion can be totally or partly and temporarily excluded from the economic precedence (RTE [74], p. 85).

At the distribution level, a consultation was carried out by the DSO ENEDIS from November 30th, 2018 to February 28th, 2019, on the use of local flexibilities for DSO's needs [101]. The answers and a summary of the contributions will be published in June 2019. ENEDIS mentions that the use of local flexibility could be useful for DSOs: (i) to manage the network in case of extreme weather conditions and of unplanned interruptions; (ii) to manage planned maintenance; (iii) to defer or to reduce network investment (for instance in case of congestion issues). This consultation discusses the potential market-based valuation for the flexibility available on the distribution networks. It addresses a series of key points on how a potential new operational scheme could be deployed to provide flexibility to DSOs, such as: the competitive procedure to select service providers (including the way to target the relevant geographical zones), the contractual framework, the activation process, the measurement or assessment of the flexibility actually delivered.

3.1.5.4 Italy

The market splitting in 6 regional price zones is the principal mean to manage transmission congestions. Intra-zonal congestions are managed by re-dispatch via the ancillary services market (mercato Servizi Dispacciamento, MSD). As described by GME [57], the MSD consists of the ex-ante MSD and of the Balancing Market (MB), both take place in multiple sessions, as defined in the dispatching rules.

- The ex-ante MSD consists of six successive scheduling substages, the results of which being known on the day before the day of delivery for the first one and successively on the day of delivery for the other 5. In the ex-ante MSD, Terna, the Italian TSO, accepts energy demand bids and supply offers in order to relieve residual congestions and to create reserve margins.
- The MB also consists of 6 sessions, all starting on the day before the day of delivery and closing successively on the day of delivery, with the last one closing at 19:00. In the MB, Terna accepts energy demand bids and supply offers in order to provide secondary control services and to balance energy injections and withdrawals into/from the grid in real time.

According to [102], most of the wind power is generated in the south while most of the demand is located in the north. Because of congestions between the two areas, the TSO usually curtails wind power generation close to real time (30 min before delivery). At the distribution level, curtailments are more applied to solar units, close to real time (60 min before the delivery) if the unit is qualified as "automatic", or one week-ahead if the unit is qualified as "manual"[24].

3.1.5.5 Spain

In Spain a system of re-dispatching and counter-trading is used to cope with grid congestions. As described in [103], the day-ahead energy market is cleared without taking into account the technical constraints on the transmission system, and subsequently a counter-trading mechanism is used to solve the congestions that may appear in the grid.

The procedure described in [103] is as follows. After the day-ahead market clearing the system operator carries out different security analysis to identify the possible congestions that may occur in the transmission system, taking into account the result of the day-ahead energy market. Furthermore, the units that can increase or reduce their production with respect to their day-ahead market position send price and quantity bids to the system operator, who use them for congestion management. As a result, some units may have to increase or reduce their production. For those units that increase their production, the increased quantity is paid using the price in the bid they made in the countertrading mechanism, whereas the units that reduce their production are charged at the day-ahead market price. As a consequence generation units are paid only for the energy produced.

The authors of [103] and [104] then conclude that in such a mechanism, the Spanish producers may be incited to develop bidding strategies in order to be dispatched in the counter-trading scheme rather than in the day-ahead energy market and that they could "*value differently the production between importing and exporting areas*". In other words, producers may design their bids to avoid being dispatched in the day-ahead energy market, in order to be dispatched subsequently in the counter-trading mechanism that is used to solve the congestions.

3.1.5.6 Great Britain

The re-dispatching of plants close to real time is mainly organized via the balancing mechanism. All types of balancing resources are then used including generators and large industrial consumers: frequency response, reserves, reactive power. Curtailment actions are also taken into account.

National Grid ESO (the Electricity System Operator – ESO – in Great Britain) can also procure "constraint" management services and enter into contracts ahead of time with well-located providers who have the required technical capability to deliver the services [105]. Constraint management contracts enable the ESO to agree in advance technical parameters with the providers to facilitate the management of a congestion. The most common type of contract is to agree either a cap or collar on the output of a power plant. However there are different types of constraint management services that can be used to solve a specific requirement depending on the network needs. Where there is sufficient competition, constraint management services are procured by the ESO through tenders stating the specific technical requirements for each service when a network condition is identified. These requirements can be:

- specific service times and dates;
- MW output;
- ramp rates and reactive capabilities;

[24] Also see [248]

- the particular location where the services must be provided.

In other circumstances, the ESO can enter into bilateral contracts with the service providers.

There are also other types of contracts such as the Intertrip contracts, which are generally negotiated at the time of connection of generation plants (e.g. wind farms [102]) or demand sites. However commercial intertrip schemes may also be applied to existing sites by agreement [106]. An intertrip will automatically disconnect a generator or demand from the Transmission System when a specific event occurs. The service requirements are specific to the location and require an instantaneous tripping mechanism to be installed at the site. When a request to arm is sent to the site, it has to switch in the intertrip scheme to allow signals to pass from the intertrip scheme to the relevant circuit breakers. Once the scheme is armed, the site could then trip (cease output) in response to an event. "*Intertrip schemes generally operate typically in less than 100 milliseconds, allowing them to be used to resolve both thermal and stability issues*" [106]. The intertrip service is remunerated and the payment generally includes the following fees negotiated with the provider [107]:

- *"Arming fee payable whenever the Intertrip is armed by National Grid (£/settlement period)*
- *Capability Payment, annual fee to cover the installation of the scheme and staff training costs (£/settlement period)*
- *Intertrip fee to cover the cost of wear and tear and any appropriate fuel costs (£/Generating Unit)"*

At the distribution level, an important evolution of the congestion management scheme is on-going in Great-Britain. The Energy Networks Association has launched its Open Networks Project to understand how flexibility resources can be best connected to the existing grid and used to manage the system smarter and more efficiently [108].

Among different initiatives in GB, we can mention the online platform Piclo that matches flexibility providers' bids with the DSO's local need for flexibility services, as well as two concrete individual initiatives carried out by the DSOs UK Power Networks (UKPN) and Western Power Distribution (WPD)[25]. The UKPN initiative is described below.

UKPN has launched an ambitious plan to procure more than 100 MW of flexibility services from distributed energy resources [109]. In December 2018, UKPN invited flexibility providers to participate in March 2019 in a new tendering process to provide flexibility services on its distribution network [110] [111] [112], with first deliveries expected in the winter 2019/2020 and winter 2020/2021. Such flexibility services are expected to permit some deferral of network reinforcements and to facilitate the management of planned maintenance and unplanned interruptions.

Any technology or process that can shave or shift the peak demand can participate. Flexibility requirements will be published, including "service windows" (times of the day) and delivery seasons per "flexibility" zone in the grid. UKPN plans to create 25 "flexibility first" zones [109] that will be integrated in the Piclo platform. Providers will be able to bid for longer-term contracts from one to four years. The contracted service period will cover the service windows and the delivery season (contracted dates). Note that the flexibility providers are not required to have the capability to deliver for the full service window, but a minimum of 30 minutes delivery duration is required.

[25] Western Power Distribution (WPD) started a flexibility trial in the Midlands in April 2018, enlarged to the South West in the summer 2018. 121 MW answered to its flexibility tender, and 261 MW to the 2018 summer's procurement exercise.

The resources can be aggregated together into a single controllable unit of flexibility (called "flexible unit") of at least 100 kW. A "*default baseline methodology is used to calculate the flexible unit's baseline as the average generation or consumption of the flexible unit during representative historic peak periods at the time of the Competition. The flexibility provider nominates the flexible MW level from the calculated baseline. The flexible MW and baseline are fixed for the duration of the contracted service period, although the baseline can change if the facilities in the flexible unit are changed*" [110].

At any time during the contracted period, UKPN may automatically or manually instruct the flexibility provider to deliver its flexibility. The instruction will specify the start time and optionally the end time of delivery.

The flexibility provider will be paid an "availability payment" (in £/MW/h) for its availability to shave the peak during the service periods. It will also receive "utilisation payments" (in £/MWh) for the delivered energy. A performance factor (PF) is introduced for each flexibility provider, linked to his delivery performance (DP)[26].

3.2 Gas

This chapter gives an overview of the relevant market segments for the gas sector including market mechanisms and products, as well as related regulations. More specifically, information about important roles, key relationships, tariff system and the market and regulatory connections and barriers are collected, analysed and compared for the 7 case study countries of the project. To do this, the following investigation first shows the main features and then the country specific differences. This can be used as a baseline for the identification of synergies and coupling potentials between the electricity, gas and heat sectors.

Natural gas is an important component of the European goal to create an Energy Union. One means to reach this Energy Union is indeed to achieve a virtual trading hub for gas, but to build such a virtual trading hub a sufficient level of gas market liberalisation is first needed. Furthermore, hubs create demand for wholesale trading [113].

The natural gas market can generally be divided into two main market layers: The Wholesale market layer which is described in Section 3.2.2 and the Retail market layer outlined in Section 3.2.3.

Additional collected information can be found in Appendix 7.2. It includes more details about the gas demand in Europe, the main actors, the infrastructure (networks and storage) as well as gas quality and additional comments for country specific information.

3.2.1 Main roles

The main roles that can be found in the gas sector are outlined below. Actors fulfilling these roles are collected for the studied countries in Appendix 7.2.2. A more detailed analysis of the roles involved in the three sectors (electricity, gas and heat/cooling) as well as their interactions can be found in Deliverable D2.1 [114], in particular for the 7 case studies considered in the project.

- **Producers** are those players that are entrusted with the inlet of gas into the country, either through own production or by importation. Some countries like Sweden do not produce their own gas but they import it through gas pipelines or LNG carriers (ships).

[26] Ex. : if DP > 90%, PF = 1; … ; if DP < 60%, PF = 0

- **Transmission Operators** build, operate and maintain the high-pressure transmission network and (if applicable in the country) the regasification installations. In some countries, the same company acts also as **Storage Operator** who is responsible for the construction, operation and maintenance of storage facilities. Transmission Operators do not buy or sell gas.
- **Distributors** or **distribution operators** build, operate and maintain the distribution installations and the distribution network. Like Transmission Operators, Distribution Operators do not buy or sell gas.
- **Shippers** acquire and trade gas on the wholesale market, in particular to **Retailers** who then sell it to domestic and small business consumers. Delivery of contracted amount of gas is guaranteed. Therefore, Shippers and Retailers have service contracts with Transmission Operators and Distributors to use their infrastructures. They do not own infrastructures. However, they can access entry and exit capacity information from Transmission Operators and Distributors.
- The **Technical System Manager** (TSM) is responsible for the technical management of the transmission and distribution networks as well as the security of supply.
- **Independent Commission** for market oversight and regulation is an entity that oversees the gas market and the application of regulations and laws.
- **Balance Responsible Role** ensures the balance of the gas network adjusting the injections and the withdrawals in order to keep an adequate pressure in the networks to maintain the system integrity.
- **Clearing and settlement role** consists in the re-adjustment of the price of the trading transactions and the fulfilment of that transactions until its delivery, accounting and payments.
- **Market Operator** is responsible for the management and operation of the market. Generally, its main duties are: the arrangement and the acceptation of the gas market agents, the definition and the listing of the trading products, the reception of orders for the purchase of the products and the daily disclosure of the prices and volumes traded (in markets with transparency policy).
- **Traders and brokers** can also be found on the wholesale gas market. **Traders** buy and sell gas on wholesale markets on behalf of other market players. **Brokers** facilitate direct transactions between gas buyers and sellers. They sometimes even operate OTC platforms.

3.2.2 Wholesale market

The wholesale market consists of the transactions between producers and market agents. Most European wholesale gas markets have been liberalised to increase the options for supply and improve the security of supply. In those countries of the EU that have been slower at opening the market to competition, the price of gas is generally higher and the security of supply is lower than in the countries that have progressively opened their gas markets. The three most popular measures for a positive impact on market liquidity are focused on the cross-border transit capacity, the regulation of the market in relation to third-party access (TPA) and the balancing of gas and transparency. To improve transparency in the gas market, the EU has enacted regulations that forbid the spreading of incorrect information relative to supply, demand and prices of gas in order to prevent the manipulation of prices.

OTC trading usually covers long-term periods to allow buyers to plan with secured supply. Moreover, they allow producers to secure sales of gas and therefore secure high investment for exploration, production and transmission activities. OTC contracts often include “take or pay” clauses to lower the risk for producers. The latter on the other hand have the risk to sell the gas at the agreed terms independent of current market prices. OTC contracts are bilateral or through a broker. Bilateral trading has low standardisation. Nevertheless, with online platforms also being used for OTC trading, transparency increases. An example of such a platform is PEGAS (see below).

Alternatively to OTC trading, **organised markets** are in place. They usually cover two groups of products: the spot market includes day-ahead and intra-day products whereas the futures' market represents products with average spot prices or negotiated prices over a longer period (months, quarters, seasons or years). These products with longer time frame are usually standardised for example the supply of 1 MWh for each gas day during the period of delivery.

The market transactions on the organised market are made on a platform with high transparency. Standardised products are traded. The most important platform in Europe is PEGAS, operated by Powernext.

As Market Operator, Powernext SA is responsible for the operation of the Organised Gas Market segment (PEGAS Platform) and is required to undertake the necessary and appropriate duties for its due and proper operations and the economic management of its services, upholding the principles of efficiency, effectiveness, transparency, objectivity, non-discrimination and independence.

As depicted in Table 3, all studied countries use the PEGAS platform for spot and future products except Spain where the MIBGAS platform is used. It needs to be mentioned that the wholesale market in Sweden is connected to Denmark (see below). At PEGAS, clearing and settlement of transactions are carried out by European Commodity Clearing (EEC). At MIBGAS, clearing and settlement is done by the Central Counterparty (CCP). The respective trading points specify trading times for continuous trading or specific auction sessions. Furthermore, delivery times are specified depending on the product. In some of the studied countries this leads to auctions to trade capacity (also known as "rights" to access gas pipelines for gas transport) such as in Denmark, Italy and Sweden. On the other hand, Austria, France and Spain use auction for volume trading and have standardised capacity rights.

Table 3 below summarizes the products traded in the wholesale organised markets for the 7 case study countries and Table 4 gives the trading times for these products. More detailed explanations per country are then given below the tables. The following abbreviations are used: "D" for Deliverable day, "d" for trading day, "WD" for within day, and 24/7 for 24 hours a day, 7 days a week.

Table 3 - Wholesale organized exchange markets for gas

Country	Platform	Trading point	Spot products	Future products
Austria	PEGAS	CEGH VTP (Central European Gas Hub Virtual Trading Point) (operated by CEGH)	Within day Day ahead Weekend Saturday Sunday Bank holiday Individual day	Next 6 months Next 7 quarters Next 6 seasons Next 6 calendar years
Denmark	PEGAS	ETF (Exchange Transfer Facility) (operated by Energinet.dk)	Within day Day ahead Weekend Saturday Sunday Bank holiday Individual day	Next 6 months Next 7 quarters Next 6 seasons Next 6 calendar years

Country	Platform	Trading point	Spot products	Future products
France	PEGAS	PEG (operated by GRTgaz)	Within day Day ahead Weekend Saturday Sunday Bank holiday Individual day	Next 6 months Next 7 quarters Next 6 seasons Next 6 calendar years
Italy	PEGAS	PSV (operated by Snam Rete Gas)		Next 3 months Next 7 quarters Next 6 seasons Next 6 calendar years
	MGAS (operated by GME)	MPGAS (spot) MT-GAS (future)	Within day Day ahead 2-days-ahead 3-days-ahead Specific products upon request	Monthly Quarterly Half-yearly Yearly
Spain	MIBGAS	PVB (operated by MIBGAS)	Within day Day ahead 2-days-ahead, 3-days-ahead, Up to last day of month ahead	Next 3 months Next 4 quarters Summer Winter Seasonal Next 2 years
Sweden	connected to Denmark			
UK	PEGAS	National Balancing Point (NBP) (operated by National Grid)	Within day Day ahead Weekend Saturday Sunday Bank holiday Individual day	Next 6 months Next 7 quarters Next 6 seasons Next 6 calendar years

Table 4 - Trading times for wholesale market products for gas

Market	Product	Trading time
Austria	Within-day (WD)	Continuous trading at the last 15 min of every hour
	Day ahead and hour ahead	Continuous trading
	3 months, 4 quarters, next 3 seasons and next 2 calendar years	Continuous trading from 8:00 a.m. to 6:00 p.m. (CET)

<table>
<tr><th>Market</th><th colspan="2">Product</th><th>Trading time</th></tr>
<tr><td>Denmark</td><td colspan="2">Within-day contracts, day contracts, weekend contracts, month contracts, spread contracts</td><td>Continuous trading and physical delivery. Trading can be executed 24/7 for contracts with short maturity and from 8:00 to 18:00 CET on exchange days for month ahead contracts.</td></tr>
<tr><td>France</td><td colspan="2">Within-day, daily, week-end and days of week-end, week-end and bank holidays, month ahead, quarterly ahead, semester ahead, year ahead or locational</td><td>Until 9:00 a.m.</td></tr>
<tr><td rowspan="2">Italy</td><td colspan="2">Day-ahead, within-day</td><td>6:00 a.m. to 2:30 a.m. of following day</td></tr>
<tr><td colspan="2">Forward products (MT-GAS)</td><td>9:00 a.m. to 5:00 p.m.</td></tr>
<tr><td rowspan="5">Spain[27]</td><td colspan="2">Within-day, day ahead, balance of month and month ahead (auctions in the organised market)</td><td>From 8:30 a.m. to 9:30 a.m.</td></tr>
<tr><td rowspan="4">Products in continuous market trading</td><td>Within-day product (WD)</td><td>D
From 9:35 a.m. to 9:00 p.m.</td></tr>
<tr><td>Daily product (DA, D+2, D+3)</td><td>D-3 until the D-1 From 9:35 a.m. to 5:00 p.m.</td></tr>
<tr><td>Rest of the month products (BoM)</td><td>From Monday to Friday, between the first day of the month and the fifth day before the beginning of the next month</td></tr>
<tr><td>Next month products (M+1)</td><td>From Monday to Friday during the month before the delivery</td></tr>
<tr><td>Sweden</td><td colspan="2">Day, day ahead, before the weekend and for the next month</td><td>Continuous trading and physical delivery. Trading can be executed 24/7 for contracts with short maturity and from 8:00 to 18:00 CET on exchange days for month ahead contracts.</td></tr>
<tr><td>UK</td><td colspan="2">Daily</td><td>8:00 (D-1) to 2:35 (D+1)[28]</td></tr>
</table>

As shown in Figure 4, the UK trading point is the one with the most participants. This reflects the competition level which influences the prices of traded products.

[27] Spain counts with two market sessions (Daily and Within-day Session) and there are two sorts of negotiations: auction-based trading and continuous market trading.

[28] The OCM (The trading Screen Product) is open for trading twenty-four (24) hours a day, seven days a week, with the exception of a daily maintenance window between 03:40 and 04:00 during which the markets are not available. https://www.theice.com/products/43396041/UK-OCM-Gas-Spot

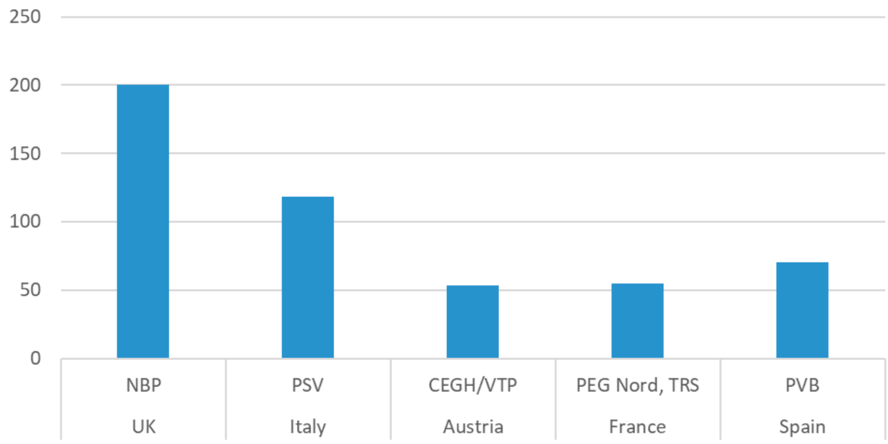


Figure 4 - Market participants at hubs [115]

3.2.2.1 Austria

For the OTC market, bilateral trading activities and settlement happen on PEGAS. "*The [Multi Trading System] allows the settlement of bilateral trades in the Austrian entry-exit system combining several transmission pipelines, storage sites and the domestic Austrian grid as well as conjunctions to neighbouring systems*" [116]. The CEGH (Central European Gas Hub) operates the VTP (Virtual Trading Point) and cooperates with the Market Area Manager and network operators to take care of the physical flow of traded gas and the fulfilment of designated and matched amounts of gas.

For the organised exchange market, standardised products are traded at the VTP on PEGAS. The commodity exchange clearing house ECC offers the services for clearing and settlement of the exchange transactions (and as well for OTC trade registrations). The organised exchange market consists of two segments: the spot market and the futures market.

Within-day products can be traded 24 hours a day, 7 days a week (24/7). There is a continuous trading possible in the first 45 minutes of each hour. During the last 15 minutes of each hour, a call phase happens to determine the price of the auction. Matching happens automatically. The minimum trading size is 1 MW and prices are set in €/MWh. Day-ahead and hour-ahead products can be traded continuously and be delivered physically from 6:00 a.m. (d+1) to 6:00 a.m. (d+2) and traded 24/7. This also includes weekends and bank holidays. The minimum trading size is 1 MW and prices are set in € per MWh. The matching procedure is click and trade.

In the futures market segment, products for the next 3 months, the next 4 quarters, the next 3 seasons and the next 2 calendar years are also traded continuously. Physical delivery happens from 6:00 a.m. (d+1) to 6:00 a.m. (d+2). Trading hours are from 8:00 a.m. to 6:00 p.m. (CET). The minimum trading size is 1 MW and prices are set in €/MWh [116].

3.2.2.2 Denmark

Bilateral OTC trading happens at the virtual point GTF (Gas Transfer Facility). The price of traded gas is not market-driven, but set by the shippers that are part of the particular bilateral trade. Shippers announce their wish to buy or sell a product on Energinet's Bulletin Board.

The Danish wholesale market is based on a simple entry-exit model (see Figure 5) which allows market players to commercially move gas in and out of Denmark. Denmark has four entry points (at Nybro, Ellund and Dragør for natural gas and BNG Entry for bio natural gas) and a single exit zone which covers six distribution areas (each operated by a distribution company) to deliver gas to all the Danish consumers. Furthermore, there are three transit exit points (at Nybro, Ellund and Dragør) for the export of natural gas. Capacities at the Entry and Exit Points at Ellund and Dragør are marketed at the online platform PRISMA and sold at Auctions according to the auction calendar and general terms and conditions for use of PRISMA capacity platform applicable at any time [117]. In the event PRISMA is not available, capacities are sold on the basis of First Come First Served (FCFS) as default procedure.

Annual, Quarterly and Monthly Capacity is auctioned by using an ascending-clock auction algorithm. Capacity for Daily Capacity and Within-day Capacity is auctioned by using a uniform clock price algorithm. Both are auction algorithms fixed in the PRISMA platform. In the ascending-clock auction algorithm, bids can be changed while the bidding round is open. On the other hand, in the uniform clock price algorithm, there is just one bidding round and shippers can place up to 10 bids for the auction.

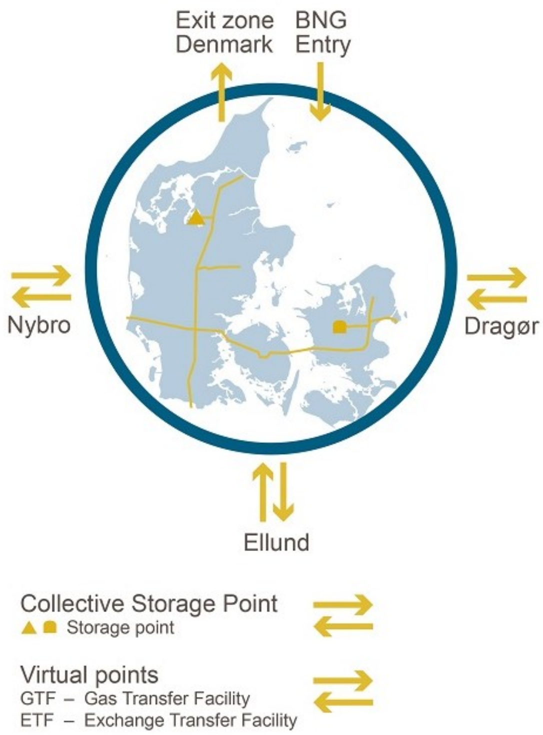


Figure 5 - Model of the Danish gas market (Source: Energinet)

In case of FCFS, the shipper must have registered one or more Capacity Users by completing the Online Access Agreement if he wants to use the Booking Procedure on Energinet Online to submit capacity orders and conclude capacity agreements according to FCFS via Energinet Online. According to FCFS, capacity orders are accepted in the order in which they are processed by Energinet. A capacity order submitted under the Booking Procedure is processed immediately after it has been submitted by the shipper.

Spot and future exchange products are traded through the virtual point ETF (Exchange Transfer Facility). The trading platform is Gaspoint Nordic which is now part of PEGAS. ETF trading products are based on continuous trading and physical delivery. Due to physical delivery, market players need to enter into a Shipper Framework Agreement with Energinet.dk to ship gas in the Danish transmission system before joining Gaspoint Nordic. Trading can be executed 24/7 for contracts with short maturity and from 8:00 to 18:00 CET on exchange days for month ahead contracts. All trading participants are shippers registered with the Danish TSO, Energinet.dk [118].

Sixteen different contracts can be traded at PEGAS for the ETF hub. Those are within day contracts, day contracts, weekend contracts, month contracts, and spread contracts. Within-day and day contracts are tradable 24/7, 365 days a year. The total amount of gas is 24 MWh per delivery day – based on a 1 MW contract.

3.2.2.3 France

The OTC contracts cover mostly long-term contracts (20 or 30 years) to import gas from Russia, Algeria or Norway. These contracts include typically "take or pay" clauses as described above. Furthermore, there are brokered OTC transactions with standardised products.

Since November 2018 there is one Trading Region in France (TRF) with a single virtual trading point: PEG. It is operated by GRTgaz and results from the merge of the previous two virtual trading points PEG Nord and TRS.

The organised gas market segment covers two types of trading principles: auction-based trading and continuous market trading.

In the auction-based trading, the agents may submit purchase and sales (bid/ask) orders for a certain product listed in a sub-segment, within the trading window from 8:30 am to 9:30 am. Once the auction has closed, the market platform operator integrates all the purchase and sales orders received, plotting, respectively, the purchase and sales curves for that product and determining the resulting price.

In the continuous market trading, the orders are processed as they are posted on the Trading Platform until 9:00 pm. If a new order posted is competitive with pre-existing orders of the opposite sign in the Order Book, the order is matched with those orders and the trade is firm; otherwise, it remains in the Order Book. If an order is conditional, the conditions specified for each one will be taken into account. Several products are negotiated: within-day, daily, week-end and days of week-end, week-end and bank holidays, month ahead (and month +2/3/4), quarterly ahead, seasons ahead, year ahead, locational products and locational spreads (capacity purchase downside a congestion point and simultaneous capacity sale upside for spread or congestion treatment).

The activity of the organised wholesale market has significantly risen since 2014, from the point of view of number of transactions (+9,5%) or exchanged volume (+21%). Simultaneously, the number of players on this marketplace has slightly decreased (106 down to 103), which underlines a stronger market concentration [119]. The players are suppliers, shippers, energy brokers or financial traders [120]. The 2016 exchanged gas volume on the organised markets has reached 632 TWh, which represents around 130% of the overall national consumption.

3.2.2.4 Italy

Gas imports are delivered mostly via long-term oil-indexed contracts, which have come under pressure since 2008. The – at times significant – lower spot prices compared to long term contract prices has created some financial discomfort for importers of gas contractually required to buy oil-indexed gas but forced to sell to their wholesale/retail customers at prices linked to the spot market. As in the rest of Europe, renegotiations of prices and "take or pay" volumes have started. Despite the (still) long duration of these contracts and the 'bubble' of over-contracted gas in the early 2010s, additional imports are already under consideration, both in the form of pipeline gas and LNG.

At the PEGAS platform, future products can be traded on the Italian virtual trading point (PSV) for the next 3 months, 7 quarters, 6 seasons and 6 calendar years. The PSV is operated by Snam Rete Gas. The applicable period is the gas day with delivery from 6 a.m. to 6 a.m., every day of the year.

On the other hand, on the national market for natural gas ("MGAS"), spot products can be traded at the so-called "MPGAS" level and forward products can be traded on the "MT-GAS" market [121]. The applicable period is also the gas day as above.

Several markets are part of MPGAS, in particular MGP-GAS, MI-GAS and MPL. Continuous trading can be done on the day-ahead market MGP-GAS for up to three days-ahead from 6:00 a.m. until 2:30 am of the following day. Furthermore, on the intraday gas market MI-GAS, trading happens continuously from 6:00 a.m. until 2:30 a.m. Finally, specific locational products can be traded upon request on the MPL market. Following the receipt of an activation request from Snam Rete Gas for a MPL session, the market operator GME publishes on the MGAS information system the trading hours, and the opening and closing hours of this session.

Forward products can be traded at MT-GAS every day from 9:00 a.m. to 5:00 p.m. for monthly, quarterly, half-yearly and yearly periods.

3.2.2.5 Spain

The low standardised OTC trades are not transparent in negotiated prices, just transactional volumes need to be specified for control reasons. In Spain, these transactions represented 98% of all gas transactions in 2016 [122]. Contracts at the OTC segment regulate the operational and credit risk issues of transactions, and let shippers deal with other counterparties. Customers contract gas supply as a bundled product with services and access fees, but big consumers can acquire gas directly with TPA and pay only the fees for access to the transmission and distribution networks.

As mentioned in the introduction of the chapter, Spain does not use the PEGAS platform for the wholesale spot and futures products. The platform used in Spain is MIBGAS, it is operational since the end of 2015 and is still growing. In 2016 the share of this market represented 2% of the gas demand (6,566 GWh).

There are 6 different products in this market:

- Within-day product (WD): for the gas negotiated on the deliverable day. This gas is traded every day.
- Daily product (DA, D+2, D+3): for the gas negotiated since the D-3 day until the D-1 day (being D the deliverable day). This product is also traded every day.
- Rest of the month products (BoM): for the gas traded after the next day of the negotiation until the last day of the month. This product is negotiated from Monday to Friday, between the first day of the month and the fifth day before the beginning of the next month (both days included).
- Next month products (M+1): for the gas that is going to be delivered the month after the negotiation. This product is negotiated from Monday to Friday during the month before the delivery.

The organised gas market segment covers two types of trading principles: auction-based trading and continuous market trading. The negotiation starts with the auctions and ends with the continuous market trading. For auctions, the agents may post purchase and sales (bid/ask) orders for a certain product listed in a sub-segment, within the trading window from 8:30 to 9:30. Continuous trading is possible from 9:35 until 17:00 (for the daily session) or until 21:00 (for the within-day session) with the same matching process as the one described for France. Four main products are negotiated at the Virtual Transmission Balancing

Point (PVB): within-day, daily, for the rest of the month and for the following month. Agents can present their offers anonymously and once an offer is matched the transaction must be done at the clearing price. The result of this transaction is communicated to Enagás, as Technical System Manager (TSM), to transfer the gas to the balance point (PVB).

Additionally, there are three products traded in auctions which help increasing the liquidity at MIBGAS:

- Operation gas, which is the gas needed for the correct operation of the transport system, mainly used in the compression stations. This gas is traded every day in the daily market opening.
- Cushion gas for the Yela's storage. This gas is traded in the auction for daily, rest of the month and next month products.
- Reserve gas, which is traded on the auction opening of the daily and within-day products.

3.2.2.6 Sweden

Due to the design of its network, the Swedish natural gas market is closely linked to the Danish market. See above for more information of the Danish wholesale market.

The balancing operators (see Section 3.2.4) in the Swedish natural gas system are active on the Danish gas market, particularly on the Gaspoint Nordic exchange, which since November 24th, 2016, is part of PEGAS. All trading on Gaspoint Nordic is done with physical delivery and operators must have an agreement with the Danish transmission network operator, Energinet.dk. An operator needs to reserve capacity in the Dragör pipeline in order to transport natural gas to Sweden. Transmission capacity is auctioned at Energinet.dk's ordinary capacity auctions. Because of the low consumption in relation to the system's transmission capacity, there is no risk of transmission congestion with today's levels of consumption. Once in Sweden, the gas is sold to users such as industries and gas distributors. Since October 1st, 2016, there are five Swedish balancing operators that have agreements with transport operators in the Danish market and can reserve capacity from Energinet.dk.

3.2.2.7 United Kingdom

Gas is bought and sold by gas shippers who transport gas to Britain or within Britain. Those gas transporters and shippers have to comply with the UK and EU legislation and conditions, as well as the conditions of the industry-governed Uniform Network Code (UNC) which changes have to be approved by OFGEM (Office for Gas and Electricity Market).

The OTC segment consists of brokered transactions on the British wholesale market. The different trading products are for different periods: within-day, day-ahead, months, quarters, summers, winters and years. OTC transactions are bilateral, standardised and transparent but remain unregulated and negotiated.

Spot and future products are traded at the PEGAS platform for the National Balancing Point (NBP), operated by National Grid. This market is standardised, cleared and anonymous. The futures exchange market is organised by ICE. It is regulated by the Financial Services Authority. APX also provides third-party services for the clearing. The financial services authority is responsible for the regulation. The trading happens continuously during trading hours (London: 7:00-17:00).

Daily contracts can be for day-ahead, balance of week, Saturday, Sunday, working days of next week, balance of month. Future products can be traded for up to 83 consecutive months, 13 consecutive quarters, 14 consecutive seasons or 6 consecutive years.

3.2.3 Retail market

The retail market comprises transactions between retailers and final consumers. The intention of the European Commission is to liberalise the retail market as well as the wholesale market as free competition allows for innovative services for consumers and prices based on the balance between supply and demand. All of the studied countries have a liberalised retail market, where consumers can freely choose their retailer.

Each retailer provides their tariff offers with different prices and conditions. Charges are often divided in fixed rates due to capacity contracted – in order to have access to the distribution network – and a variable term which represent the gas supplied, the increment of the gas price, etc. depending on the company or the country.

Additionally, consumers can choose a regulated tariff if they meet certain requirements in France and in Spain.

Figure 6 and Figure 7 below show the natural gas prices for household consumers and for industrial consumers respectively in the case study countries. These figures show that the gas price in Sweden is very high compared to the price in the other countries, and that taxes in Sweden and Denmark are higher than in the rest of the countries. Moreover, the VAT and other taxes represent only a very small share of the gas bill for household consumers in the UK and for industrial consumers in Italy, Spain and the UK.

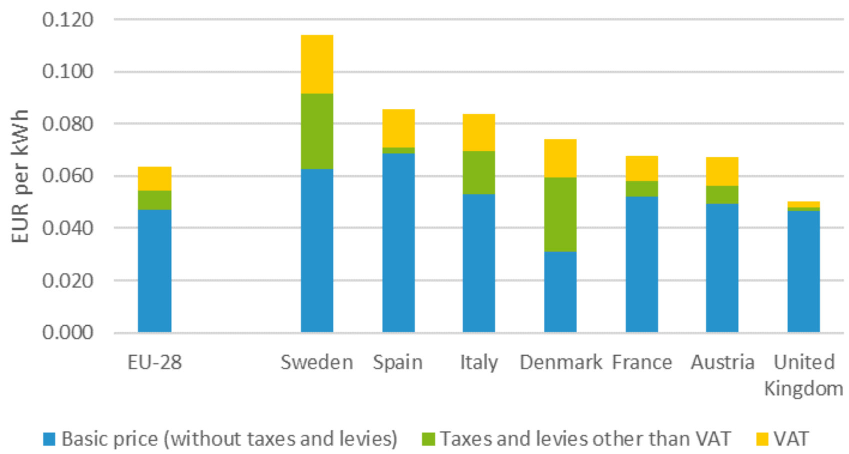


Figure 6 - Gas prices for household consumers during the second half of 2016 in EUR per kWh[29] [123]

[29] Note: annual consumption: 20 GJ < consumption < 200 GJ; Source: Eurostat [123] (online data code: nrg_pc_202)

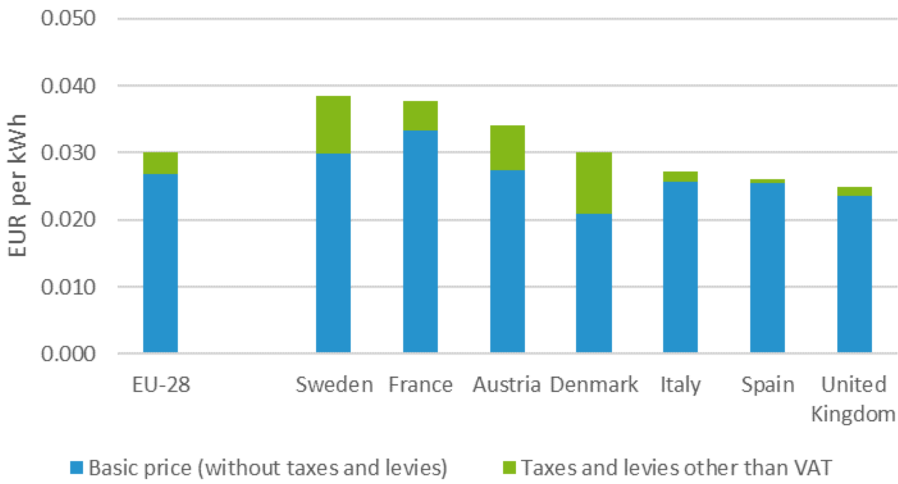
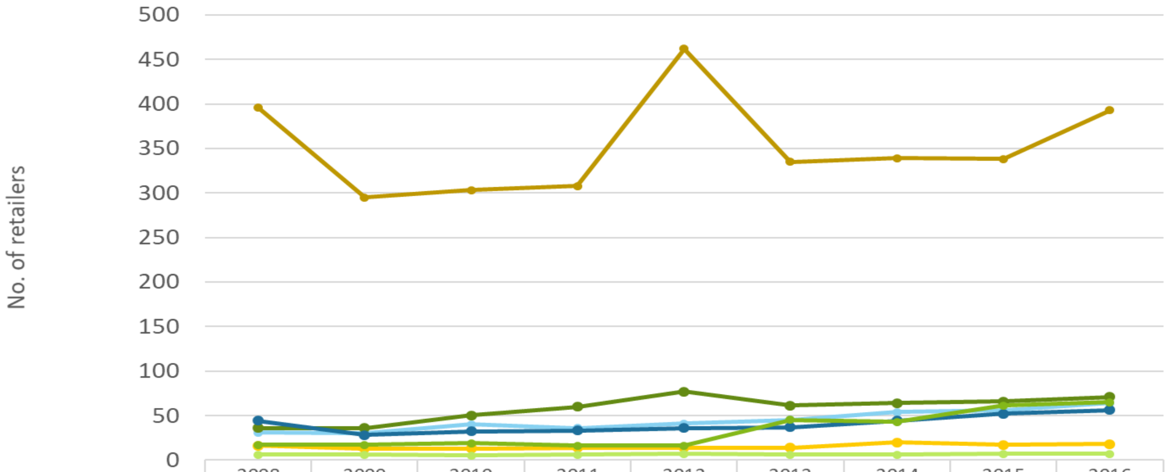


Figure 7 - Gas prices for industrial consumers during the second half of 2016 in EUR per kWh[30] [123]

The number of stakeholders can affect the market. For example, in a market with a sufficient number of retailers, clients will have more offers to choose from and competition will be higher.

Figure 8 shows the number of retailers selling natural gas to final customers. It can be seen that Italy has by far the highest number of retailers and that this number highly varies over the years. The reasons for this situation are explained later in this section. The number of actors in France, Austria, Spain and the UK have considerably increased since 2009.



	2008	2009	2010	2011	2012	2013	2014	2015	2016
Austria	31	30	40	36	41	45	54	56	64
Denmark	16	13	13	14	14	14	20	17	18
France	36	36	50	60	77	61	64	66	71
Italy	396	295	303	308	462	335	339	338	393
Spain	44	28	32	33	36	37	44	52	56
Sweden	6	6	5	6	7	6	6	7	7
United Kingdom	17	17	19	16	16	45	43	61	65

Figure 8 - Number of retailers selling natural gas to final customers [123]

[30] Note: annual consumption: 10 000 GJ < consumption < 100 000 GJ; Source: Eurostat [123] (online data code: nrg_pc_203)

3.2.3.1 Austria

As of the 1st of November 2002, the domestic sector for natural gas was opened to competition [124].

The free gas market segment is organized in such a way that retailers offer their rates and it is up to the consumer to decide which retailer is most suitable for them. Generally, if your consumption is higher, you will pay higher fixed costs but lower variable costs and vice versa. In 2016, the amount of gas that has been supplied to consumers equals 87,880 GWh. As of the 1st of January 2013, a new entry-exit-model for the Market Area East has been established. The new market model resulted in an increase of competition.

In Austria, entry and exit charges are calculated based on the distance from the virtual trading point.

Standard bills consist of 4 parts:

- An overview part with the supplier´s contact details and information about the bill (billing period, total cost, consumption during the billing period, etc.).
- Detail of the customer’s consumption: conversion from cubic metres into billed kWh, composition of the energy price (charges applied, unit rate per kWh, etc.), overall grid charges (for example, for grid losses or metering charge), taxes and sub-charges.
- Information sheet with the supplier’s and system operator’s contact details and information about the contract.
- A fourth part with explanations to understand the bill.

3.2.3.2 Denmark

Contrary to other countries, where capacity and gas are traded independently, in Denmark customers buy natural gas as a bundled product, including under the name of “natural gas” the gas and also the transmission and distribution services. However, customers have to sign two different contracts: one for the distribution service and another one for the supply.

Gas consumers in Denmark can freely choose their supplier. However, the consumer must actively choose a commercial supplier and accept a supply contract to enter this market. Gas suppliers must comply with the following conditions in order to be allowed to supply gas in a distribution area: 1) the gas supplier must have entered into a framework agreement with the gas TSO and has to be registered into the Register of Players, 2) the gas supplier must have entered into a framework agreement with the distribution company and approved consumer portfolio into the Register of Players, 3) the gas suppliers’ IT system must be tested and approved for Electronic Data Interchange (EDI) communication [125].

The Natural Gas Supply Act assigns the task of promoting **transparency** in the retail market of natural gas to DERA (Danish Energy Regulation Authority). DERA has appointed the consumer homepage www.gasprisguiden.dk to Energinet.dk, where information on products and prices are available and comparable, and to which all supply companies are obliged to report prices and terms. DERA has the regulatory oversight of this price comparison tool, which it uses when monitoring prices and the transparency of contractual obligations [126].

The final consumers in the Danish retail market are:

- Daily metered consumers who are mostly enterprises with remotely read gas meters.
- Non-daily metered consumers who are mostly households, whose consumption is metered every month or year.

With regards to the guarantee of supply in Denmark there are two groups of consumers depending on the emergency of supply with two different tariffs: one tariff for protected customers and a lower tariff for non-protected customers.

3.2.3.3 France

The Gas Free market segment is organised in such a way that retailers offer their rates (for different annual consumptions) and it is up to the consumer to decide which retailer is the most suitable to them. If your consumption is higher, you will pay higher fixed costs but lower variable costs and vice versa.

Table 5 gives a detailed description of all the elements of a gas bill on the free market and all the charges which are part of it.

Table 5 - Split of charges of a gas bill for final consumers [127]

Charge	Description
Fixed charge	Transport and Distribution tolls, €/year (defined by TSO/DSO)
Variable charge	Unit price of gas, €/kWh (defined by the retailer)
Transportation tax[31] (CTA)	Depends on retailer's customer portfolio [128]
Tax on gas consumption (TICGN[32]) (including carbon tax)	0.00845€/kWh
Subtotal	Sum of the former three charges
5,5% VAT 20%	Fixed charge Variable charge (+ CTA & TICGN)
Total Charge	Final gas bill for a final consumer

If the client subscribes to a single supply contract, the agreed rate covers both storage and transport and distribution network costs (like they are defined for the regulated tariff, see below). Market competition is then based on both gas supply costs and marketing & sales costs.

The variable rate depends on client's geographical location in as much as transport and distribution cost may differ. The spread between the most expensive and the cheapest zones may reach around 19%.

[31] Contribution tarifaire d'acheminement

[32] Taxe Intérieure sur la Consommation de Gaz Naturel

Table 6 - Type of Rates for the Retail market [129]

Rate code	Description
Base	For domestic users with a consumption lower than 1,000 kWh/year (e.g. for gas consumers with gas-fired cookers)
B0	For domestic users with a consumption lower than 6,000 kWh/year (e.g. for gas consumers without gas heating system)
B1	For domestic users with a consumption between 6,000 and 30,000 kWh/year (e.g. for gas consumers with gas heating system)
B2i	For domestic users with a consumption between 30,000 and 150,000 kWh/year (e.g. property around 2,000 m2 with gas heating system)

In November 2016, the European Commission proposed a legislation to permit price regulation such as for social tariffs for a transition period.

Beside the free market there exists a regulated tariff set by the government under recommendation of the market oversight commission or regulator (CRE). This regulated tariff is open to any residential customer (and small apartment blocks) with an annual consumption less than 30,000 kWh/year. The regulated tariff has been strongly questioned and it has just been removed from the large apartment blocks sector (with a collective heating system).

This rate is revised by the government every three months according to an official formula. This tariff can be proposed by historical players (ENGIE and 23 local companies also acting as local DSOs). Upstream and infrastructure cost represents on average around 81% of the regulated tariff (see Figure 9).

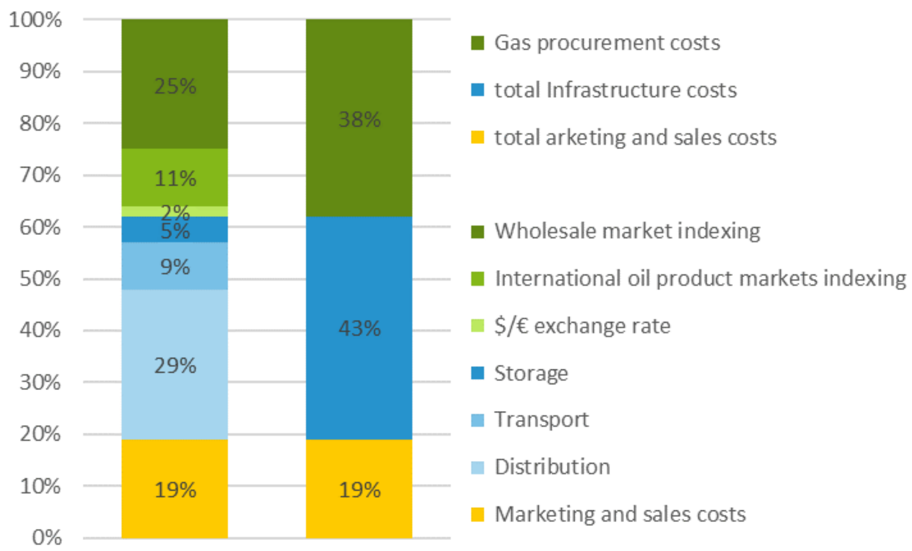


Figure 9 - Average regulated tariff structure in France (Year 2015, Data-Source: [130])

3.2.3.4 Italy

The Italian gas retail segment is more fragmented than the wholesale segment, although market concentration is still significant. Following the European liberalisation of the natural gas sector, in 2011 two Ministerial Decrees divided the Italian territory in 177 “Ambiti Territoriali Minimi” (ATEM), which are groups of municipalities located in the same geographical area. According to law n. 124/2017, retailers have to offer at least a standard rate with fixed price to households and small businesses and another rate with variable price according to an index for reference.

The Regulatory Authority of Energy Networks and Environment introduced the PLACET offer (Free Price for Protection Conditions) which obliges retailers to offer a rate for families and small businesses clear and understandable with fixed or variable prices fixed by contractual conditions defined by the Authority. These contracts can be renewed every 12 months [131].

The new rules on the size of local markets and on bidding criteria aim at contributing to attract a new market structure, also by significantly reducing the number of small companies and by creating new business opportunities for present and new operators. The new regulatory framework indeed provides an opportunity – which is not seen in other countries' gas markets – for business operators to shape a new local gas distribution market framework, thus allowing a small bunch of market operators to gain the market shares.

The Italian gas tariffs consist of two components: a fixed amount and a variable amount. The variable amount is calculated on the basis of the requested cubic metres of gas plus an amount to be paid for spot services. Customers can choose between a fixed-price and a variable-price indexed to wholesale gas price. Italy counts with one of the highest charges for gas transmission: 34.4% (2018). The tariff structure is regulated by Resolution No. 120/2001.

3.2.3.5 Spain

The Gas Free market segment is organised in such a way that retailers offer their rates (depending on annual consumptions) and it is up to the consumer to decide which retailer is most suitable for them. If your consumption is higher, you will pay higher fixed costs but lower variable costs and vice versa.

A more detailed description of the different elements in a gas bill is given in Table 7.

Table 7 - Split of charges of a gas bill for final consumers

Charge	Description
Fixed charge	Transport and Distribution tolls, €/year (defined by the DSO and in line with the rules of the National Energy Commission)
Variable charge	Unit price of gas, €/kWh (defined by the retailer)
Hydrocarbon Tax Regulation	0.234 c€/kWh for domestic consumption
Subtotal	Sum of the former three charges
21% VAT	VAT
Total Charge	Final gas bill for a final consumer

Other considerations:

- There is also an option to have a flat rate (variable charge does not apply, and fixed charge includes tolls and gas consumption). If you overpass the contracted gas supply, the variable charge applied to that overconsumption will have a higher cost than normal rates.
- The duration of the contract between retailer and consumer in competitive contracts may vary depending on the contract conditions.
- If you have a Rate 3.2 (see Table 8) and consume less than 5,000 kWh/a, or if you have a Rate 3.1 and consume more than 5.000 kWh/a, the rate is automatically updated at the end of the year by the retailer.

Table 8 - Type of Rates for the Retail market

Rate code	Description
Rate 3.1	For domestic users with a consumption lower than 5,000 kWh/year (for gas consumers without gas heating system)
Rate 3.2	For domestic users with a consumption between 5,000 and 50,000 kWh/year (for gas consumers with gas heating system)
Rate 3.3	For domestic users with a consumption between 50,000 and 100,000 kWh/year (property around 2,000 m^2 with gas heating system)
Rate 3.4	For domestic users with a consumption higher than 100,000 kWh/year (building around 10,000 m^2 with gas heating system)

Apart from the free market, Spanish consumers can choose another tariff, called “Tarifa de último recurso” (“Last Resort Rate” - LRR). This is a regulated gas tariff set up by the government that allows consumers to sign up for if they use less than 50,000 kWh/year and they have a low-pressure gas supply. Most residential consumers meet these requirements and can get this rate from one of the last resort retailers of gas. This rate is revised by the government every three months.

3.2.3.6 Sweden

The final step in opening the natural gas retail market to competition was taken in July 2007, and all natural gas consumers have been free to use the natural gas supplier of their choice since then.

The west Sweden natural gas network has approximately 36,000 customers, of which the biggest are major industries and cogeneration power plants, while around 34,500 are household customers [132]. Stockholm's city and vehicle gas network has around 63,200 household customers and about 900 business customers, including 10 industries [133].

With regards to the retail price, consumers' total cost for gas has changed relatively little since the deregulation in 2007. The reason for this is that the gas trade price has remained relatively stable around 30-35 öre/kWh. Network charges have also remained relatively stable at approximately 20-27 öre/kWh. However, taxes on natural gas have increased by around 10 öre since 2007. The single biggest cost component, at 48 percent of household customers' total gas costs, is made up of VAT and energy tax.

In Sweden, the **natural gas costs consist of two parts**. Firstly, customers pay to be connected to the network, the so-called **network cost** which is paid in öre/kWh. The second part is to pay to the gas trading company (**gas price**). If the gas trading company and gas network company are part of the same group, the costs are usually co-financed.

Swedish gas suppliers and gas network companies must provide clear information about consumer's invoices and rights as well as about how to submit a complaint. According to the Swedish Natural Gas Act, the gas dealer is obliged to inform its customers about the content of an agreement before the contract is concluded. Likewise, the gas dealer must notify the customer in advance when the gas contract expires and explain what happens with price and contract terms if the customer does not actively enter into a new agreement before the old one terminates. Before changing the terms of the agreement, the consumer must be informed by a special notice. The message states that the consumer can terminate the agreement. The new terms may not be applied until two months after the notification has been sent to the consumer.

3.2.3.7 United Kingdom

Since the late 1990s full competition is introduced into Britain's retail energy markets. After that, gas consumers can freely choose their gas supplier. In order to ensure the retail energy market works in the interest of consumers, OFGEM[33] monitors the market and, if necessary, takes action to strengthen competition or enforce the market rules.

The gas distribution tariffs are composed of:

- System capacity and commodity charges, which vary depending on the Local Distribution Zone (LDZ) and are calculated in terms of peak day kWh and kWh per day in the Supply Point Offtake Quantity (SOQ).
- Customer (capacity) charge. This charge varies depending on the annual consumption of the client:
    - For an annual consumption lower than 73,200 kWh per annum, the customer charge is a capacity charge.
    - For an annual consumption between 73,200 and 732,000 kWh per annum, the customer charge consists of a fixed charge and a capacity charge based on the registered SOQ.
    - For an annual consumption greater than 732,000 kWh per annum, the customer charge is calculated according to a function related to the registered SOQ.
- Exit capacity charges, which is calculated in terms of peak day kWh per day. These charges are applied per exit zone, which is determined by the postcode.
- Entry commodity charge or credits depends on the point of supply and it reflects the benefits of the entry of gas instead of using the distribution networks.
- Shared supply meter point allocation arrangements.
- Other components. In the United Kingdom the Climate Change Levy (CCL) is the only levy applied on gas consumption. Consumers who sign a Climate Change Agreement have a 65% percent of reduction of this levy. Furthermore, consumers that use a feedstock gas are exempted from this levy.

There is also an optional LDZ tariff for large consumers located close to the National Transmission System which (with a single charge) is more attractive than the common tariffs.

Customers can choose paying bills at the moment of delivery, every 3 months, quarterly or monthly, depending on the tariffs offered in their LDZ. Furthermore, they can also choose between paying a fixed or an indexed price.

[33] Office for gas and electricity market

3.2.4 Balancing system

The importance of an adequate balancing system lies in the need of having a secure system. Fluctuations in the balance between injections and withdrawal of gas cause variations in the gas pressure, which can threaten the system integrity. For this reason, it is crucial to have a balancing system that ensures that the pressure remains within the limits established for the network.

When an imbalance is detected various actions can or need to be undertaken. For example, the balance can be restored by increasing or reducing the gas supply or even the gas demand (market actuations), modifying the gas pressure in regasification installations, injecting gas from storage, etc.

Table 9 summarizes the balancing options in the different case study countries.

Table 9 - Summary of balancing system in the case study countries

Country	Nature of actuations	Responsible
Austria	Market	AGGM
Denmark	Market	Energinet.dk
France	Market	Gas TSOs (GRTgaz and Terega)
Italy	Storage market and localised products market	SNAM Rete Gas
Spain	Storage, regasification and markets	TSM and COS
Sweden	Balancing contracts with balancing operators and network storage	Swedegas
United Kingdom	Storage	*No information*

3.2.4.1 Austria

Since 2013 every user of the gas grid has to belong to a balancing group. This includes distribution and transmission systems. Suppliers and big consumers can have a direct contract with the balance responsible party. Other consumers have a supply contract with a supplier, which automatically includes them in the same balancing group. The manager of the market area is responsible to administrate the balancing groups. For the market area balancing, daily differences are balanced per balancing group which is undertaken by the market area manager. Within a balancing group, the coordinator of the balancing group is responsible for balancing. This happens with a daily balance for consumers with a standard load profile and maximum contracted peak demand of 10,000 kWh/h. Consumers with a contracted peak demand of 50,000 kWh/h have an hourly balance. Other consumers can choose between hourly or daily balancing, as long as they have an online measuring system [134].

Clearing and settlement agents are responsible for gas clearing and settlement (AGCS[34]). They calculate the quantity of balancing energy daily and hourly and settle the same with balancing responsible parties. Hourly auctions are organised for physical balancing energy. The market area managers coordinate network

[34] AGCS Gas Clearing and Settlement AG, www.agcs.at

development and maintenance. They are also responsible for the balance group management and market area management. The distribution area manager (AGGM) is responsible for access and capacity management, control of gas flow, long-term planning for the distribution grid infrastructure and management for emergency and bottleneck situations.

3.2.4.2 Denmark

The responsible for gas balancing in Denmark is Energinet and it is the shippers' duty to balance their deliveries and offtake to reduce the number of balancing actions by Energinet.

Energinet calculates the system's capability regarding the pressure limitations, "worst case" scenarios and operational limitations of the system. The calculation is made with data about the estimated offtake at the exit zone, nominations at entry/exit points, gas storage injection and withdrawal and net imbalance of the previous days. With the results of the calculation, Energinet provides a margin called "green zone", which represents the market flexibility for the following days.

If the total delivered gas is not equal to the total offtake, there is an imbalance and the shipper must pay to Energinet a quantity according to the imbalance. If the data performance for within-day data is below a specific level, Energinet pays the shipper a specific amount computed in accordance to [135].

In case of imbalance, shippers may pool imbalances although it is up to Energinet to restrict the pool for a part or for all of the Danish Gas System.

Table 10 gives an overview of the daily balancing mechanism for the Danish Gas System.

Table 10 - Daily balancing of Danish Gas System

Before the Gas Day	At 13:00, Energinet informs the shipper about its expected offtake of Non-Daily Read Metering Sites for each Allocation Area for the following Gas Day based on forecast.
During the Gas Day	Starting at 6:45 on the Gas Day, Energinet shall publish the Estimated Balance for the Gas Day, every hour on minute 45 until 2:45 on Energinet Online.
Actions during the Gas Day	If the Estimated Balance is in the Yellow Zone, Energinet may trade every hour between 9:00 and 18:00 and within the time intervals 20:05-20:15 and 23:05-23:15 respectively. Energinet publishes at Energinet Online information on the highest purchase price and the lowest sell price of Energinet's trades at Gaspoint Nordic. (Yellow Zone is the area on each side of the Green Zone)
Following Gas Day	Before 14:00 Energinet informs the shipper of the Daily Imbalance Quantity allocated to the shipper and publishes the Calculated Balance for the previous Gas Day.

3.2.4.3 France

In France, there are two balancing areas and the responsible for network balancing of an area is the TSO of that area.

Each shipper is subject to a balancing obligation on a daily basis. In other words, the shippers have the obligation to balance daily their gas injection to the network with their withdrawal, relying on their customer portfolio demand. In case of negative imbalance (withdrawal larger than injection), the supplier has to pay the TSO an imbalance price. Conversely, in case of positive imbalance, the TSO buys the shipper its imbalance. To meet their obligation, the shippers can contract with storage facility owners at an auction-based price. If this is not enough to ensure the financial sustainability of the storage operators, the latter receives a compensation revenue from the TSO which is defined by the market oversight commission [136].

In addition to the shippers' balancing obligation, to balance the network, the TSO can use the storage flexibility of the pipelines, the physical storage facilities or it can use market services [137]. For instance, GRTgaz uses the PEGAS Platform (operated by Powernext) to purchase and/or sell gas on the within-day or on the day-ahead markets.

If it is not sufficient, additional services can be procured through a call for tender mechanism such as the "Locational" products (capacity purchase or sale at specified locations). Since 2015, via the Locational Balancing Platform, GRTgaz can very rapidly call up all the PEGAS market participants to participate in the system balancing by providing on short notice flexibilities at located physical points or specific delivery hours [138].

3.2.4.4 Italy

In 2011, Italy integrated a new balancing system to create a competitive, transparent, efficient gas market. Part of that is a balancing platform (PB-GAS) operated and organised by GME. This platform is composed of two markets: MPL for trading of localized products and MGS regulated market for the trading of stored gas. Both markets are integrated into the MPGAS platform described earlier in Section 3.2.2 [121]. SNAM Rete Gas is responsible for the physical balancing of the Italian gas system. On the one hand, as previously explained, SNAM Rete Gas can request the organisation of MPL sessions in order to procure localised products to manage deviations between overall injections and withdrawals on the network. On the other hand, MGS is a daily auction-based market which allows authorised players to place bids and offers for available storage resources. In particular SNAM Rete Gas places bids and offers to mitigate the overall imbalance of the system. A daily auction mechanism selects bids and offers based on a merit order. Imbalances are cashed out at a balancing market price [139].

Storage facilities are the biggest flexibility option for SNAM Rete Gas to physically balance the system (see also Section 7.2.4 in the Appendix). Stogit (part of SNAM group) owns more than 95% of the storage capacity.

3.2.4.5 Spain

The balancing of the Gas System was implemented in Spain on the 1st of October 2016. The balance area is mainly established in the Commercial Operative Storage (COS), regasification plants and underground storage. The actions made by the Technical System Manager (TSM) to keep the balance in a certain area can be of two types: buy/sell normalised products in short term and balancing services.

The normalised gas products in short term are defined as gas located in a certain balancing area that the TSM can obtain or sell to accomplish balancing actions. In the COS, the balance is defined as the daily balance of entries and exits of gas: Imbalance = Entries – Exits.

The balancing services are allocated by public tenders when it is not possible to buy/sell normalised products in short term or when it is unlikely that they can solve the unbalance. The duration of the balancing services is below a year and their starting date would be lower than twelve months after the agreement between the COS and the service bidder.

The users (suppliers, retailers, direct consumers) are responsible of keeping their gas portfolio in balance and the TSM is responsible of keeping the system in balance within the normal operational limits. The gas balance is reviewed at daily level for a gas day from 6 h to 6 h.

The balancing operations are regulated by the Circular 2/2015, of 22nd July, by the CNMC, which fixes the rules for the transport network balance.

3.2.4.6 Sweden

As transmission network operator, Swedegas owns the West Sweden natural gas network and is responsible for its operation and maintenance. On June 1st, 2013, the government appointed Swedegas as the system balance authority for the West Sweden natural gas network.

In order to guarantee balancing, Swedegas enters into balancing contracts with operators in the gas market, known as balancing operators. The balancing operators take financial responsibility for ensuring that the customers' consumption is matched by supply. The West Sweden natural gas network provides ample possibilities to store gas in the pipelines (known as line pack) which facilitates balancing. Short-term imbalances are allowed to make up as much as 25 percent of consumption on a typical day in winter without jeopardising the network's technical function.

The system balancing operator may not enter into contracts with individual gas balancing operators without approval by Ei (Swedish Energy Market Inspectorate) of the contract's terms and conditions.

3.2.4.7 United Kingdom

National Grid Gas plc, which is the Britain's System Operator, is the company that is responsible for ensuring that the gas supply matches the gas demand on a daily basis among other duties. Balancing tasks are carried out through real-time operations and control actions. They implement the strategies planned for the continuous monitoring and control of the network gas pressure, volume flow and storage capacities, etc., in order to meet the actual demand variations. At the transmission level, storage utilization, control of compressor stations and control of gas supply into the network are used to meet the demand variations. At the distribution level storage control and utilization is a key task which is performed in an order decided by the operators, depending upon the storage availabilities.

A balancing market, called On-the-day Commodity Market (OCM) is in place and operated by the ICE Endex exchange (appointed by National Grid). Anonymous trades for day-ahead and within-day products take place on this market. Localized products can be traded. The OCM is open every day until 2:35 am.

3.3 Heat

3.3.1 The role of district heating in meeting the national heat demand

Although the potential for recovery of heat from industrial processes exists, interconnections between industrial heat networks and district heating systems are still rare. Moreover, figures concerning heat production and consumption and available heat within private industrial heat networks are not easily available. Some figures concerning steam purchase to another party (industrial heating) tend to confirm that some synergies within local multi-firms industrial heating networks are already operated.

In the following sections, we will mainly focus on district heating for residential and commercial buildings.

In most of the case study countries, district heating (DH) seems to play a minor role in the heat supply, around 2% up to 5%. Sweden turns out to be an obvious exception as DH stands for more than 50% of the national heat supply (expressed in TWh). Similarly, in Denmark, district heating is the most important heating source in the residential heating sector. 64.4% of all Danish households are connected to district heating systems, not only for space heating but also for domestic hot water [140].

Indeed, if heat supply is the main activity of the DH networks, they can also supply domestic hot water (DHW).

In many countries (such as France, Sweden), some district cooling networks also exist (see Table 12).

Table 11 - Heat and Domestic Hot Water demand (final consumption split into different fuels) and share of district heating

Heat and DHW consumption (TWh)	Austria [141] [142]	France [143]	Italy [144]	Spain [145]	Sweden [146] [147]	UK [148]	Denmark [149]
Electricity	7,95	60			20	48.3	
Gas	21,90	135			0.9	398.5	7
Heat Network/district Heating	16,75	17.3	9		41	12.5	35.6
Oil	12,87	53.5			2.5	43.5	3.5
Biomass	21,80	95.3		45.8	13	43.2	6.5
Others	3,84	7.1		3.5	1	8.5	5.5
Total	85,11[35]	368.2	370	408	78.4	554	58.1
% District Heating	19,7%	4.7%	2.4%		52.3%	2.3%	61.2%

Table 12 below shows the numbers and lengths of the heat and cooling networks in the case study countries. Unlike electricity and gas, whose supply relies on a national grid, DH is made of a set of non-cohesive networks (e.g. around 200 networks in Italy and Sweden, slightly less than 700 in France), mainly located in medium or large cities.

The buildings supplied by these networks are mainly multi-family houses or commercial buildings. Sweden differs from other countries as the DH networks have a 25% market share of the single-family heat supply. In general, Denmark has an extensive and varied heat sector: public heat supply (cities) is generated by 16 centralised CHPs, 285 decentralised CHPs and 130 decentralised DH plants. Heat supply to the private sector (enterprises and institutions) is generated from 380 CHPs and 100 DH plants.

Table 12 - Size of Heat and Cold Networks

	Austria	DK	France [150]	Italy [151]	Spain [152] [153]	Sweden [154]	UK [155]
Number of Heat / cooling Networks	ca. 1600		669	240	352	400	5500
Length (km)	5400	60000	5015	4300	202	38889	1800
Number of cooling networks	ca. 10-20		included above		Approximately 600 km		included above
Length (km)			included above		3	506	included above

[35] Including chillers / cooling energy demand

Although industries may have private heat networks, the latter are not counted as such but rather as fuel (gas/electricity/other) delivery points. The case of Sweden can be mentioned, where industrial heat network customers stand for a share of 8% of the overall DH market. As already mentioned, interconnections between industrial heat networks and district heating networks exist but do not seem to be very developed and data on the synergies between industries in the frame of a local industrial heating network are not readily available.

UK differs from the other countries with a surprisingly high number of district heating networks (5500) compared with the share of consumed heat they stand for (2%). This stems from the definition of district heating networks adopted as networks that supply at least 2 buildings and at least 1 customer. If these micro-DH are not taken into account, the number of standard DH networks is much lower and in the range of other countries (about 200 large DH networks).

The energy mix used by DH for the heat production heavily differs from one country to the other as shown in Table 13.

Table 13 - Energy mix for the heat production of heat networks

	Austria [141]	Denmark [149]	France [150]	Italy [151]	Spain [156]	Sweden [154]	UK [155]
Share of RES	**49%**	**48.3%**	**53%**	**26%**	**80%**	**93%**	**12%**
Waste recovery	4%	11.7%	25%	26%	2%	51%	1%
Biomass	42%	33.6%	21%		71%	40%	10%
Geothermal	3%	2.3%	4%		1%	1%	1%
Others		0.7%	3%		6%	2%	
Share of fossil fuel	**51%**	**51.7%**	**47%**	**74%**	**20%**	**7%**	**88%**
Gas	44%	18.8%	39%	74%	17%	3%	88%
Oil	3%	0.7%	1%		3%	2%	
Coal	4%	20.3%	6%			1%	
Others		11.9%	1%			0%	

Renewable and recycled energy account for more than 90% in Sweden whereas these kinds of sources account for around 12% in the UK. Italy (26% of RES) and France (53%) are in an intermediate position from this point of view.

In the considered countries, combined heat and power plants (whether they are fossil fuel or RES-fired CHPs) represent a significant share (30% up to almost 60%) of heat facilities whereas the share of conventional fossil boilers has been declining.

Some particular national features can be pointed out.

Namely, in Denmark, 67.4 % of all DH is produced in cogeneration with electricity (CHP). In general, the large-scale CHP units are located in large urban areas whereas the small-scale CHP units and DH boilers are located in smaller cities and villages. The large-scale networks typically consist of a number of distribution heat networks interconnected by a transmission heat network. Heat is produced by a variety of different plants including large generation plants (based on coal, biomass or natural gas), municipal waste plants, surplus heat from industry, and peak load boilers. An example of a large central DH area is the Greater Copenhagen DH system, where the distance from the eastern to the western part of the system is approximately 50 km. One very important element of all Danish DH networks is short-term heat storage.

This means that the CHP plants can optimise their cogeneration according to the electricity demand without compromising the heat supply. Both large and smaller DH systems use short term heat storages.

Recycled (including recovered) heat is quite used in Swedish heat plants (32%) and in France (25%), but it is not really developed in the UK and it is bound to play a minor role in the future (as only 8% of DH network under development relies on this source).

Geothermal energy and heat pumps play no significant role in district heating in the UK and still play a minor role in France and Sweden (less than 4% of the district heating supply). In Denmark, geothermal energy and heat pumps also contribute, albeit to a lesser extent: geothermal energy is used in Thisted for DH and covers heat consumption for 2,000 houses and in Copenhagen area 1% of Copenhagen's total heat consumption is supplied by geothermic heat. Future district heating plans though, include the introduction of large heat pumps at medium and small scale CHPs and smaller heat pumps (with low temperature DH) and electric boilers.

Although the role of DH is still limited in most EU countries, they are promoted by national energy policies and supported by national regulations. The latter also promote the increase of the share of renewable and recycled energy in these networks (see following section), especially in countries where they do not play a significant role.

3.3.2 Regulations

The main questions regarding the European benchmark of heat networks regulation are:

- Is district heating considered as a public service or not?
- How are DH tariffs set in the considered countries?
- What is the level of market deregulation? Are district heating networks unbundled?
- Is there a general policy for the promotion and the development of district heating?
- Is there an obligation for households to connect to an existing district heating network (for instance when a new house or apartment block is built)?
- What are the other policy and regulation aspects concerning district heating?

3.3.2.1 Public service or not?

European countries can differ in their gas and electricity regulation policy (fully deregulated markets or existence of both regulated and deregulated ones), but in the case of district heating there is generally no unbundling and no national regulated price in the studied countries (although price schemes might have to be approved by local or regional authorities in some countries), whereas it can exist for electricity or gas government-approved fixed and/or variable components of the tariff. Even when district heating is considered as a public service or a natural monopoly (and therefore strongly regulated), pricing always depends on local specific conditions. Table 14 describes the public service status in the 7 case study countries, along with the status of the DH owners and operators and the tariff regulation.

Table 14 - National DH sectors, regulation and players' status

Countries	Public service status (= strong state regulation)	Status of DH owners and operators	Existing/oncoming tariff regulation
Austria	No tariff regulation existing	Mainly public (municipality- or state-owned companies), private possible.	There are general laws applicable to avoid inadequate high pricing of district heating but no dedicated regulation of the heat tariff. Tariffs are depending on grid operator.
Denmark [157]	Yes	**Large cities** (originally power plants): owned by large energy companies. Centralized CHP (production only). Transmission usually unbundled. **Smaller centres** (originally DH plants/CHP) during the 1980s and 90s: usually joint production and distribution. Owned by municipalities or local consumers	Danish Energy Regulatory Authority regulates the full consumer price of district heating. Private consumers' complaints about DH companies concerning purchase and delivery of heating are handled by the board of appeal within the energy area.
France [158]	Yes Status of public service depending on local authority (since 2015/08/17)	Ownership: public (municipality-owned) Operation: private, private/public or public	Network specific pricing (no national regulated price). Obligation to define a variable (with a metering system) and a fixed fees. Tariffs setting in the delegation contract (if operated by a private or private/public company), relying on a unique principle for all consumers.
Italy	No (with exceptions) but considered as "natural monopoly"	Private (for heat production) Public or private/public (DH operation)	Through the competition with gas and electricity as an alternative heat fuel. Service quality regulation (with a metering obligation). In some specific cases (obligation to connect to DH), tariffs are regulated by the oversight commission. Commercial behaviour code for pricing information communicated to consumers.
Spain	No	Public (47% of networks), private (48%) and public/private (5%)	-
Sweden	Yes	Private Municipality-owned State-owned	No price regulation but obligation to display comprehensive information on price determination. Supervision by the Swedish Energy Market Oversight Body especially when an abuse of dominant position is suspected.
United Kingdom	No (Unregulated in the UK)	Housing associations (Social and private) Private organisations Local/municipal authorities	No price regulation. Tariffs vary widely from supplier to supplier. However, the Heat Network (Metering and Billing) regulations 2014 implement the requirements in the Energy Efficiency

Countries	Public service status (= strong state regulation)	Status of DH owners and operators	Existing/oncoming tariff regulation
			Directive with respect to the supply of distributed heat, cooling and hot water. The government is supporting industry-led initiatives to improve consumer protections and technical standards. These include the Heat Trust and the CIBSE Code of Practice.

3.3.2.2 Existing policy for promoting district heating and other regulations in the considered country

In this section, we consider policy and regulation following two main considerations (which are linked but nevertheless distinct):

- Is the national development of DH considered as an objective in itself (as part of an energy transition plan) and what are the related tools?
- Is the DH sector impacted by current policy & climate regulations only in as much as they can be a way to increase the share of RES (and assimilated) in heat production and consumption?

Table 15 describes the policies, regulation and supports in the considered countries in order to promote and develop the District Heating sector.

Table 16 presents other regulation aspects that can have an impact on the district heating sector although they can cover a larger scope. These aspects are generally related with national Energy transition schemes (energy efficiency certificates, tax scheme…).

Table 15 - Existing national policies for promoting & extending the District Heating sector

Countries	Policy for District heating development strategy	Regulation and support for a specific DH project	Regulation and policy support for arising the share of RES (including waste recovery) in heat production of DH	Obligation for households to connect to an existing DH
Austria	District heating is considered as a measure to increase the national energy efficiency and thus embedded into the national energy efficiency strategy.	Dedicated act to support construction of district heating and cooling networks. Dedicated cogeneration act to support cogeneration for public heat supply (and process heat generation). Support for new district heating projects is possible according to a law which regulates the funding of measures for environmental protection. Heat customers can receive funding for a new grid connection from federal governments.	Direct support for efficient cogeneration (Green Electricity Act, Cogeneration Act). Indirect support via the national Energy Efficiency act.	In some regions (e.g. with increased immission levels) new buildings are required to connect to existing heat networks.
France [158]	Mandatory regional DH mapping and master plan. National obligation on local authorities owning a DH built before 2009 to realize a 10-year master plan.	Heat fund for project with a RES Share >50%. Obligation for a large new urban project to make a feasibility study of a DH. Financial support for DH feasibility study for any municipality over 10000 inhabitants without DH. Mandatory cost-benefit analysis of the use of industrial waste heat in DH for any new large DH project.	Reduced VAT for consumers of a DH with RES/Waste recovery share >50%. Heat fund for project with a RES Share >50%. Mandatory cost-benefit analysis of the use of industrial waste heat in DH for any new large DH project. Energy Transition law: target of a 5-fold increase in RES/Waste heat share in DH towards 2030.	Not for existing buildings. Possible (depending on local authority) for new/deep renovated buildings as soon as the considered DH has a RES/Waste recovery share >50%.

Countries	Policy for District heating development strategy	Regulation and support for a specific DH project	Regulation and policy support for arising the share of RES (including waste recovery) in heat production of DH	Obligation for households to connect to an existing DH
Denmark [159] [160] [161]	First Heat Supply Act on District Heating (1979) introduces a national heat plan. Municipalities are assigned a key role. This Act also introduces supply zones all over Denmark. It secures economy of scale and optimal use of capacity. 1986 Co-generated Heat and Electricity Agreement: decentralised cogenerated heat and electricity became a major energy policy priority. Heat zones after 1990: new decentralised CHP and conversion of existing decentralised DH units by administrative orders in 1990-98.	Amendment to the law on heat supply in 1990 ('project system'): conversion of DH plants to co-generated heat and electricity plants. As of 1 July 2003, CHP was exempted from the obligation to cogenerate electricity and heat continually in order to qualify for electricity production subsidies. Now, plants produce electricity when there is demand and when the price is therefore favourable, and produce heat when there is demand. The regulations currently in effect establish two general guidelines for DH supply: one deals with the conversion to co-generated heat and electricity and with regulations on fuel consumption; the other covers the conversion of large-scale customers (central heating plants) to public supply. There is also a series of specific planning directives.	Biomass Agreement of 14 June 1993 [1]: "The parties agree that environmental considerations indicate that the use of waste in connection with DH production shall henceforth take precedence over other fuels". Biomass Agreement (further amended on 22 March 2000): The goal was to ensure a more flexible choice of biomass, including the possibility of using surplus wood (chips).	Municipalities have the right to impose compulsory connection and continuation to DH networks (1982-Obligatory connection). Existing buildings have a grace period of 9 years. Ban on installing electric heat in new buildings (1988).
Italy	The Italian Regulatory Authority must ensure, through its supervision activities, the development and completion in the DH sector.	-	-	In some specific cases
Spain [153]	No	Support to DH Network in Móstoles, Madrid (2012), and grants for the second phase of the project (2018).		No
Sweden [162] [163] [164]	Swedish climate roadmap. Integrated Climate & Energy Policy (50% of RES in the total final energy consumption).	District Heating Act (SFS 2008:263 DH commercial practice)	-	No law-based price fixing but obligation to display comprehensive information on price determination.

Countries	**Policy for District heating development strategy**	**Regulation and support for a specific DH project**	**Regulation and policy support for arising the share of RES (including waste recovery) in heat production of DH**	**Obligation for households to connect to an existing DH**
United Kingdom [165]	Committee of Climate Change estimates 18% of UK's heat will need to come from heat networks by 2050. The future of heating: meeting the Challenge (BEIS) No specific policy for district heating networks available. It is discussed in the general umbrella of policy on heating.	UK Government Heat Network Delivery Unit (for supporting the commercial development of ongoing DH projects). UK Government Heat Network Investment Project (financial support). Scottish Government's District Heating Loan Fund.	Renewable heat incentive (premium payment scheme for renewable heat generators) and district heating networks that supply renewable heat are eligible for grants.	None

Table 16 - Other regulation aspects impacting national DH sectors

Countries	Framework policy impacting DH sector	Regulation for Energy Efficiency	Others
Austria	Yes (see Table 15).	New or expanded use of district heating is applicable as energy efficiency measure according to the Energy Efficiency Act.	Cogeneration Act, Green Electricity Act.
Denmark [159] [161] [160]	**Heat Plan Denmark 2010.** **Heat Plan Denmark 2008.** Copenhagen Carbon Neutral 2025. 2009 EU Climate and Energy Package: Denmark is committed to achieve at least 30% RES in gross final energy consumption by 2020 and to reducing emissions from non ETS sectors by 20% by 2020 relative to the 2005. Current Danish government platform includes a target of at least 50% RES by 2030 and a 100% renewable energy system by 2050.	Danish Energy Agreement for 2012-2020: half of the electricity consumption will come from wind power, enabling a share of 35% RES in gross energy consumption in 2020.	Energy Research Programme (ERP - 1976): to prioritise and support energy research and technological development. Development Programme for Renewable Energy (DPRE - 1981): supplement the ERP so that research into renewable energy could lead to commercially viable technologies.
France	Energy Transition law (2015/08/17).	Integration of some DH renovations in the Energy saving certificates scheme (white certificates). Consideration of DH as a potential source of RES by the 2012 thermal code given the DH carbon content. Full consideration of the DH as RES by oncoming thermal code based on the share of RES and Waste recovery in heat production.	-
Italy	-	-	Reduced taxes on heat produced by a CHP plant.
Spain	No	Minimum heat demand coverage by RES for new buildings, which can hamper a DH deployment if it is not fuelled (at least partially) by RES.	-
Sweden [163]	Swedish climate roadmap. Integrated Climate & Energy Policy (50% of RES in the total final energy consumption).	-	Application of environmental taxation (CO2, sulphur, nitrogen oxide) to DH (but not to electricity generation).
United Kingdom [165] [165]	Legally binding Carbon budgets require a 57% reduction in greenhouse gas emissions from 1990 to 2030. Carbon plan - Reducing greenhouse gases. Future of heating - Meeting the challenge. Green transition Policy.	Energy Company Obligation (ECO) scheme on heat & electricity suppliers as potential financing source for DH renovation.	Industrial heat strategy. Gas network innovation.

3.3.3 Tariffs schemes

The following benchmark of tariffs schemes aims to distinguish price items and costs items (both from the DH user's perspective) and to establish a relationship between them.

As explained above, it seems there is no nationally regulated district heating pricing, unlike for gas and electricity. Prices seem to be set for every heat network given local conditions but they might have to be approved by local or regional authorities in some countries.

In most cases, a dual tariff scheme based on fixed and variable fees is applied to district heating in the analysed countries. Fixed fees are supposed to cover facilities and network investment as well as maintenance costs, whereas variable fees cover fuel purchase for heat (domestic hot water production). A mark-up is generally applied in a kind of "cost +" perspective. However, in some cases, tariffs definition must consider the potential competition of alternative heat fuels such as gas and electricity in the frame of a kind of "netback approach" (upside investment and energy procurement costs should ensure a competitive final customer price compared with alternative fuels).

In Denmark, according to DERA regulation of prices for district heating plants is based on a non-profit principle, where prices may only reflect the necessary costs of production and administration. The prices of each district heating plant therefore reflect the costs of the plant in question. The consumer pays the lowest of either the cost-based price from the provider or the cost of an alternate form of heating.

The price level for district heating and the share of fixed and variable fees in the total price can strongly depend on the heat production technologies. For instance, in France DH networks mainly fuelled by geothermal Heat Pumps (HP) display a much higher share of fixed fee (64%) than the ones relying mainly on heat recovery (32%).

These observations might explain to some extent why there is no national price regulation for district heating.

Beyond these considerations, the paragraphs below depict national specificities concerning fixed and variable fees of district heating networks.

3.3.3.1 Austria [166]

100% of DH operators applies a dual fixed and variable fees structure.

- **Fixed base tariff** (mainly for households) and **peak consumption fee** are based on the power of the heat exchanger. They are supposed to cover investment costs, capital costs, operational costs and to a certain extent maintenance costs. At the initial connection, a grid connection fee must be paid for coverage of the costs of the consumer's connection to the heat network (capacity investment costs). A yearly rent for the heat meter must be added on in order to cover metering costs.
- **Variable fees** are **energy fees** which depend on actual heat consumption. They cover the fuel purchase for heat production.

3.3.3.2 Denmark

- **Fixed contribution** depends on the occupant's residential area, the property, to some extent the volume of heat consumption (stepwise decreasing fixed fee with increasing volume of consumed heat),

the maximal flow capacity (which could be based on the last 3 years of heat demand). It covers potentially fuels costs (partially), costs for installations, grids and pipelines, buildings connection to the network and inventory, installation and grid maintenance, network operation/administration, insurance, CO_2 taxes, energy taxes and sulphur taxes on fuels.
- **Variable contribution** depends on actual consumption and might be seasonally adjusted. It covers fuel costs and operating & maintenance costs.

3.3.3.3 France [167] [168] [169] [170]

100% of DH operators applies a dual fixed and variable fees structure in as much as it is legally mandatory.

- **Fixed fees ("R1" fees)** are yearly fixed fees and depend on housing heat exchanger capacity expressed in €/kW (to be split between several users in apartment buildings). They cover capacity investment and maintenance costs, network refurbishment costs, power purchase for operating heat production facilities.
- There are **two kinds of variable fees ("R2" fees)**:
    - For each DH, there is a fee component which depends on consumed heat and is calculated with an annual or seasonal variable price (expressed in €/MWh). It covers fuel purchase for heat production.
    - When the DH also provides domestic hot water (which is not always the case), a second fee component depends on consumed hot water (expressed in €/m^3). It covers fuel purchase for domestic hot water production (but not the consumed water).

3.3.3.4 Italy

- **Heat exchanger costs** depend on heat exchanger power rate (expressed in €/kW). They cover taxes, license fees paid to municipality and operation & maintenance costs.
- **Energy costs** depend on user type (residential, service sector or industry) and on consumed heat. It covers fuel (e.g. gas or electricity) purchase for heat production and DH network losses.

3.3.3.5 Spain

- **Fixed fees** are applied for **connection rights**.
- **Variable fees** are related with the actual heat **consumption**.

3.3.3.6 Sweden [170] [171] [172]

- **Two kinds of fixed fees** can be distinguished:
    - **Fixed constant Costs** are applied by 65% of DH operators in order to cover housing network connection (maintenance) costs.

  - **Capacity Costs** are applied by 67% of DH operators. They depend on customer's capacity need which is estimated from previous consumption data (14%) or is based on a general category figure method (user's classification). They cover capacity investment and maintenance costs.
- **Two kinds of variable fees** can be distinguished:
  - **Energy costs** are based on metered heat consumption. Prices might be constant (59% DH companies) or seasonal (37% DH companies) with higher winter prices. They cover fuel purchase for heat production and are applied by 100% of DH operators.
  - **Flow costs** depend on the volume of consumed hot water. They cover fuel purchase for heat production for domestic hot water production and supply. Only 42% of DH operators apply this kind of fees.

3.3.3.7 United Kingdom [173]

- **Fixed fees**, when they are applied, cover housing network connection costs, network (pipes) investment costs and heat facility investment costs.
- **Variable fees** cover fuel purchase for heat production.

3.3.4 Main roles and the associated stakeholders

This section is devoted to the identification of the main roles involved the DH sector and the associated stakeholders. An overview in the 7 case study countries is then given.

The main roles involved in the DH sector are usually:

- Heat production plant owner(s).
- Heat network owner.
- Heat network operator.
- Heat supplier (this role is often carried out by the heat network operator).
- Customers.
- Professional organisations.
- Oversight and supervision bodies.
- Other players.

In most cases, local authorities are key stakeholders inasmuch as they are involved in the DH operation (through a public or private/public company) or in its supervision through public service delegation contracting. Heat production plant owners can be the DH operator or just have a supply contract with the DH operator (for instance an industrial site owner selling its heat surplus or a waste recovery operator). The role of national bodies can differ from one country to another, especially in supervision activities (non-national supervision of DH in France for instance, regulation is done at local scale).

Table 17 - District heating stakeholders in the considered countries

	Heat production plant owner	Heat Network owner	Heat network operator	Customers	Professional organisations	Oversight and supervision bodies	Other players
Austria	Operator of district heating network (no unbundling required) Additional 3rd party heat generators are possible (e.g. industrial waste heat)	Operator of district heating network (no unbundling)	Mainly public (municipality-owned) companies but private/public companies or pure private networks are possible.	Residential buildings, public buildings, commercial and industrial customers.	Chamber of employees Other agencies (NGOs) dedicated to consumer's rights.	Other authorities (energy efficiency monitoring, emission monitoring, …)	Other standardisation bodies
Denmark [161] [174]	The largest plants are owned by large energy companies, while smaller plants are typically owned by production companies, municipalities, or cooperative societies.	Local authority or municipality-owned DH companies	Local authority or municipality-owned DH companies	Residential, commercial and industrial customers	Danish Board of District Heating (DBDH) is a private organisation representing the leading actors of the Danish district heating energy sector	DERA	Varmelast.dk (A heat market group formed by CTR, VEKS and HOFOR optimizes the heat production)
France [158]	Private (e.g. waste recovery), public or public/private players.	Local authorities	Public (municipality-owned) or private/public companies Private companies under delegation from local authorities	Residential sector Service sectors	AMORCE (association of district heating operators and local authorities) SNCU Professional Association of DH companies	Local authorities	Consumers and customers association

	Heat production plant owner	Heat Network owner	Heat network operator	Customers	Professional organisations	Oversight and supervision bodies	Other players
Italy	Usually private (including industries selling their heat surplus)	Private or public organisation	Private or public operator (most heat producers are also network operator)	Residential, commercial or industrial customers	-	Italian Regulatory Agency	-
Spain [145]	Private-public participation. Private or public owner, depending on the contract.	Private-public participation. Private or public owner, depending on the contract.	Private companies/ESCO.	Residential, commercial and industrial customers. Public buildings.	ADHAC Association of companies of heating and cooling grids	-	-
Sweden [175]	Local authority or municipality-owned DH companies	Local authority or municipality-owned DH companies	Private, municipality or state-owned companies	Residential, commercial and industrial customers	Energy Companies of Sweden, which represents companies that produce, distribute, sell and store electricity, heat and cooling	Swedish Energy Market Inspectorate: analyses DH sector development, suggests relevant change measures, ensures compliance of DH companies with the DH Act. Swedish Energy Agency for energy policies issues Swedish Competition Authority: ensures absence of abuse of dominant position.	District Heating Board, mediates negotiation between DH companies and their customers (no binding decisions).

	Heat production plant owner	Heat Network owner	Heat network operator	Customers	Professional organisations	Oversight and supervision bodies	Other players
United Kingdom	Private, social housing association or local authority	Private, housing association or local authority	Private, housing association or local authority	Residential, commercial or industrial customers	Association for Decentralised Energy. The UK District Energy Association	The market is unregulated	Heat Trust's independent disputes resolution service operated by the Energy Ombudsman may help in case of disputes with the DH supplier. This service is free to customers of companies who have signed up to Heat Trust.

3.3.5 The Danish example of a regional integrated heat market [174]

The special case of the district heating system in Greater Copenhagen Area in Denmark is described here in more detail since, unlike other DH networks in Europe, it works as a heat market. Varmelast.dk, a cooperative between district heating companies, manages and operates this market.

This local market involves (in different way – see below):

- Three Combined Heat & Power plants (CHP-plants) owned by two different companies (Ørsted and HOFOR) which represent a heat production capacity of 1,700 MW.
- Three waste incineration (CHP) and one geothermal plant which represent a capacity of 400 MW and which production is politically prioritized.
- Back-up and peak-load heat-only-boilers representing a capacity of 1,400 MW.
- Two Heat Accumulators (660 MW) which help the market to be more flexible.

The objective and responsibility of Varmelast.dk are to ensure efficient production of both heat and power in making the heat plans. The control rooms of the CTR and VEKS companies[36] take care of the operation of the district heating networks (24 hours a day, 7 days a week) and Varmelast.dk supports these control rooms during operation.

Heat payment and heat load dispatch are covered by separate sets of contracts, which means that heat load dispatch happens without regard to payment between producers and district heating companies. Load dispatching is based on marginal heat costs, which differ from heat prices. The latter are defined in bilateral contracts between suppliers and buyers and are not known by Varmelast.dk. The contracts define how the total benefit from heat load dispatch is shared. All net variable costs (including CO_2 quotas and maintenance costs) are considered in the dispatch optimization process. “Net” means that they are reduced by potential revenue from electricity sales on the spot market (for CHP facilities) or additional subsidies (e.g. for biomass facilities).

In this heat market, the day-ahead heat plan is made the morning before the day of operation and it is completed by 3 intra-day adjustments (at 15:00, 22:00 and 8:00 on the next day). The day-ahead planning mainly involves the two CHP owners (Ørsted and HOFOR) and Varmelast.dk:

- The day-ahead planning starts with the daily heat demand forecast sent by Varmelast.dk at 7:45 the day before to the heat producers. This daily heat demand forecast consists for each producer of a file with district heating demands, CHP demands, and required heat transmissions. The heat demand forecast is made in advance by the district heating companies, taking into account the production forecasts provided by the waste incineration plants.
- Using this information, the heat producers prepare their bid and submit it at 8:45.
- A first optimisation and dispatch process is then carried out by Varmelast.dk who sends at 9:00 a gross daily heat power assignment to each producer (amount of heat and water for the entire day).
- On this basis, the producers send Varmelast.dk at 9:45 their preliminary heat production plan, namely the hourly production for each unit (based on marginal costs of each heat plant).
- Varmelast.dk then checks if the plans can be implemented (the plans are adjusted only if they cannot be implemented from hydraulic reasons). The heat accumulators are used to compensate for deviations between planned and actual heat demands and to enable the suppliers to place their heat production

[36] CTR and VEKS are two district heating network operators.

when it is most favourable according to the electricity market. Varmelast.dk sends back the final heat plan (hourly DH production for each unit) to the producers at 10:30.

- These latter can therefore calculate their heat production costs and the resulting electrical power they can sell on the Nordpool electricity market. They send their power bids to Nordpool at 12:00.

As mentioned above, in addition to the day-ahead planning, there are 3 scheduled intraday adjustments of the heat plan every day. They are based on updated heat consumption forecasts, updated capacities and power prices. Further intraday adjustments may occur when necessary.

The intraday adjustments are made by the CTR's control room and approved by the VEKS' control room. Varmelast.dk is involved when needed.

The market operation efficiency is assessed by a weekly operations report based on all relevant data that suppliers give to Varmelast.dk. This latter calculates the optimal load dispatch hour by hour and compares it with the actual one. The economic benchmark of actual operation and optimal plan is then shared among all stakeholders to identify improvement potentials. Difference between realized production and theoretical optimal production turns out to be around 1% of total variable costs.

4 Potential market and regulatory barriers or shortcomings

In this chapter potential barriers and shortcomings for the provision of services to the electricity system by multi-energy systems are presented and discussed, with a focus on market and regulatory aspects. It should be noted that a lot of the potential barriers considered below are not necessarily specific to MES and may apply to other types of flexibility resources.

Technological barriers are not considered in the present deliverable and are the subject of other project deliverables.

The barriers and shortcomings discussed below will be further studied in the project, in particular to propose solutions or recommendations, and they will be reassessed at the end of the project taking into account the work done.

The following sections are respectively devoted to potential barriers and shortcomings related to the electricity system as such and then to cross-sector potential issues.

4.1 Electricity system

National energy system foundations and heterogeneous national schemes

The analyses carried out in Section 3.1 for the relevant services to the electricity system show that the provision mechanisms and markets are still heterogeneous between the considered countries, despite ongoing efforts to harmonize the market designs at a European level (e.g. day-ahead market coupling; intraday market coupling; FCR, FRR and RR TSO cooperation initiatives, etc.).

This heterogeneous situation appears as a limiting factor for the provision of services by MES. It naturally follows from historical developments of the electricity, gas and heat systems in each country, namely each national design results from a specific response to a particular set of conditions or constraints affecting each national power system in a different way: different primary energy resources and generation mix; structure of the grid and location of generating resources with respect to the main demand areas; insular or continental characteristics of the electricity system; different climate conditions, population densities, industrial activities and therefore different consumption behaviours; different institutional frameworks; etc. A straightforward example is given by the upper voltage limit on the distribution network [176]: for instance 20 kV in France versus 110 kV in Austria and even 132 kV in Great Britain. Thus the “frontier” between transmission and distribution levels is quite different, which has an impact on the service provision.

The national electricity system organisation and architecture are also inherited from different political ambitions and strategic decisions, e.g. conception of the energy system in a “centralised” vs. “decentralised” way, national vs. European energy supply strategy, etc.

The needs for flexibility services will depend on the specificities of the electricity system in each country (its reliability, RES deployment conditions, existing generation mix, etc.). For instance, in a power system where only limited congestion problems are encountered, TSOs and/or DSOs will not have strong motivations to procure flexibility services to solve this type of issues compared with power systems facing or expecting to face huge congestion problems. In the same way, countries with sufficient expected future generation capacity might not have the same need of capacity requirement mechanisms as those countries where system adequacy might be at stake in the future.

However, as explained above, there is a trend towards a regulatory and market design harmonization at European level. The increasing interconnections and interdependencies between countries and the growing RES deployment expected in the future will further drive the need for integrated European electricity markets in order to provide solutions and services to cope with increasing volumes of variable RES. In particular the recently established Energy Union strategy strongly supports a new market design that would facilitate the integration of higher shares of renewable energy and foster energy efficiency measures.

More specific aspects are presented in the following paragraphs.

Rules or requirements in existing market design limiting flexibility provision by MES

Specific rules or requirements existing in some markets or service provision mechanisms might prevent or limit the provision of services by MES.

Minimum offer thresholds (or minimum bid size) might make it difficult for MES or even small pools of MES to participate in some mechanisms. For instance, the minimum offer threshold is 5 MW in Austria and Sweden for aFRR, 10 MW for RR in Spain, and even 50 MW for the Fast Reserve requirements in Great Britain. In France, the minimum offer threshold is 10 MW for the balancing market for most of the requested balancing volume, but a derogatory complementary mechanism, set up in January 2018 and enlarged in January 2019, allows small balancing units to supply offers between 1 MW and 10 MW under certain conditions [73] [74].

Some countries also have exclusivity principles for the participation in some markets. For example, a flexible unit contracted for balancing, network, or strategic reserve might be prohibited to participate in the energy market (and reciprocally).

Participation in some mechanisms in some countries is still restricted to generators and does not allow demand response nor aggregation. For instance, in Italy, aggregation is currently not allowed to participate in any of the key mechanisms such as day ahead and intraday energy markets and most balancing and frequency regulation mechanisms. A similar issue occurs in Spain for aggregated demand response, which is not authorized to participate in the FCR and aFRR services.

Some specific product requirements (ramping or response time, service duration, etc.) might be difficult to meet for certain MES technologies, either due to technical constraints imposed by the process which they are used for or due to their intrinsic technological capabilities. In the same way, high penalties for underperformance might also be an important barrier for MES participation in certain service markets. Aggregation of the flexibilities of a portfolio of MESs should contribute to some extent to overcome such issues.

The pricing method in a given service market is also important for flexibility provision. For instance, in the reserve markets, it could be more appropriate to switch from pay-as-bid pricing to a uniform marginal pricing in order to foster flexibility provision.

Finally, it should be noted that some initiatives are already taken in some countries to overcome identified barriers. For instance, as previously mentioned, the British TSO National Grid ESO will trial weekly FFR auctions in June 2019. Such a closer-to-real-time procurement is expected to increase opportunities since it will be easier for the participants to forecast their availability with sufficient certainty to participate in weekly tenders rather than the existing monthly ones. In the same way, the introduction of aggregation in some markets is being considered in Italy for the future market reform.

Attractiveness of flexibility service remuneration

The remuneration for MES flexibility shall recover the MES costs to provide these services, which means not only the operating costs but also the possible "implementation" costs. Indeed, the provision of flexibility services (in particular ancillary services such as balancing and frequency regulation) might lead to additional costs linked for instance to:

- The installation of dedicated monitoring, control and ICT equipment and/or mandatory measuring devices. For instance, SEDC [45] mentions that pre-qualification in frequency based ancillary services requires local frequency measurement equipment with accuracy and sensitivity of measurement better than 10 mHz.
- Possibly new personnel recruitment, procurement and/or development of new software tools and associated training costs.
- Increased transaction and financial costs, etc.

These additional costs required for MES to participate in the provision of services might be significant and the potential remuneration should be sufficient to recover them.

Regulatory context to encourage DSOs to promote and procure flexibility services

In some countries, there is no clear regulatory framework nor incentives for DSOs to procure flexibility services on the distribution network to meet their needs: for instance to solve grid constraints, to optimize the grid operation, to reduce network investments or defer reinforcement... This situation could become a barrier for the development of flexibility provision when DSOs are not allowed nor encouraged to procure services from resources connected to the distribution grid. As an example, currently there is no mechanism in Sweden that allows the DSOs to buy demand-side flexibility [45].

A regulatory policy for DSOs favouring CAPEX (capital expenditures) rather than OPEX (operational expenditures) can also be a barrier for emerging flexibility services, since DSOs would then invest in network development or reinforcement rather than procure services from network users or other market players. More globally, CEER (Council of European Energy Regulators) consultation [177] suggests several regulatory tools to overcome these barriers and to encourage the use of flexibility at the distribution level, such as for instance price or revenue control to stimulate some necessary DSOs decisions, economic incentive schemes for DSOs to explore innovative solutions, etc. Among the CEER conclusions on flexibility for DSOs [178], the following can be pointed out:

- the regulatory framework for DSOs should be non-discriminatory and not hinder or unduly deter DSOs from facilitating the development of all sources of flexibility that benefit the grid;
- DSOs should be able and allowed to access and use flexibility services for managing the network.

As an example, in Great Britain, the current distribution price control RIIO-ED1 2015-23 (RIIO means Revenue = Incentives + Innovation + Outputs) has promoted DSOs' innovation via an explicit stimulus package including for instance: (i) the Network Innovation Allowance, which permits to fund innovation within distributors' allowed revenue (use it or lose it), and (ii) the innovative roll-out mechanism, permitting distributors to apply for additional funding to roll-out a proven innovation[37] [179]. The local tenders organised by UKPN described in Section 3.1.5 is a direct consequence of this stimulus package.

Finally, the ongoing deployment of smart meters is also expected to encourage DSOs to request innovative flexibility options or services since the meters should increase DSOs' ability to follow up, closer to real time, loads and power flows.

Necessity to increase the DSO-TSO coordination

This issue of an increased coordination between TSOs and DSOs is of course crucial for the development of flexibility service provision, in particular to enable and foster the provision of flexibility services by resources connected to the distribution grid, which is the case for a lot of MESs. The needs of DSOs and TSOs are evolving and it is necessary to redefine their respective roles and responsibilities. It is widely agreed that solutions are likely to differ across countries, particularly because of the different structural and institutional organizations of distribution. This TSO-DSO coordination issue is presently the subject of a lot of projects, international working groups and other initiatives (see for example [91], [92], [93], [94], [95]).

Potential barriers due to network tariffs

Depending on their design, network tariffs could be either a facilitator or a barrier to the provision of services by MES. Network tariff levels and structures widely vary across the EU but they commonly respect several main principles:

- First they are designed and approved by regulators to permit network operators to fully and timely recover their allowed costs linked to their OPEX, CAPEX and depreciation (cost recovery), as well as to make each customer pay for the cost it causes to the grid (cost reflectivity). But as reminded by Schittekatte [180], there are many difficulties to implement theoretical optimal distribution tariffs. For instance, the distribution tariffs proposed in practice are only a proxy for the cost drivers. "*Designing a truly cost-reflective capacity-based charge is a challenging task. The coincident-peak of a distribution system, identified as the main network cost driver, is hard to target. Targeting the wrong network peak implies an efficiency loss, e.g. distributed energy resources (DER) adoption can be under- or over-incentivised without resulting in much change in the total grid costs*".
- Network tariffs "*should also ensure an efficient and fair allocation of costs among different customer categories, avoiding cross-subsidisation between customer classes*" [181]. Unbiased tariffs with non-discriminatory access to the grid are required by all the national regulators.
- A grid tariff structure must remain transparent, understandable and relatively simple to be efficient. The tariff design method is also expected to remain relatively stable.
- Finally, most countries impose uniform distribution tariffs over the whole DSO's area or even the whole country.

By means of network tariffs, system operators can send short-term or long-term price signals to induce changes in grid users' behaviours to reach desired network objectives [177]. Two main aspects have to be taken into account:

[37] Examples of such funded projects: the Active Network Management by SSE (Scottish and Southern Energy) including network monitoring, battery storage and thermal storage technologies to test how to avoid costly network reinforcement; Flexible plug and play by UKPN (UK Power Networks) to test new technologies and commercial arrangements in order to connect distributed generation (DG), such as wind or solar power, to constrained areas of the electricity distribution network, and then to deliver greater flexibility [249].

- The **tariff component structure** may have varying impacts on users' behaviours depending on the balance between its main components: energy component (€/kWh consumed/time period), capacity component (or demand component; €/kW/time period) and fixed component (€/time period). Debates on the optimal balance between these components are still going on and clearly show the potential contradictions between different objectives. For instance, "*there is a fear that network tariff reforms, which aim to increase efficiency, will result in an unfair allocation of the network costs, i.e. passive, often smaller or poorer, consumers would see their electricity bills increase*" [180]. This is the case with the debate on the potential increase of the fixed charge.
- The **time-based structure of network tariffs** is also important. Time-of-use network tariffs – and critical peak pricing – with different pre-defined prices for different pre-defined periods (hours, days, weeks, seasons …) aim to promote a better use of the network or support flexibility provision for network purposes [182]. In this case, price signals are used to reduce peak demand or switch users' demand from peak time periods to off-peak time periods. That is also the case with dynamic network tariffs, which are closer to real time but significantly add complexity to the system.

As mentioned above, both aspects (network tariff components and time-based structure) ensue from the objective to take into account as closely as possible the individual impacts of the network users on the grid and to fairly allocate costs between the different types of network users. They contribute to encourage behaviour patterns which are beneficial to the grid, but might turn out to be barriers to the provision of other types of flexibility services. For instance, the provision of balancing and frequency regulation services might result in switching the consumption to peak or higher network price periods, or to exceed certain thresholds leading to penalties[38]. These potential additional costs due to network tariffs have to be taken into account in the economic assessment that will determine the participation of a MES in the provision of flexibility services.

The network tariff is one component of the flexibility costs among others (e.g. electricity price, taxes, maintenance costs…) and its impact on flexibility decisions will be more or less significant depending on its weight in the final bill. For instance, Danmarks Tekniske Universitet [183] notes that for power-to-heat in Denmark electricity "*grid tariffs accounted for up to 43% in the marginal cost to produce heat in Denmark in 2014*" (compared to electricity price, taxes and maintenance costs). Other cost components are discussed below.

Potential impacts of retail prices

In the customers' bill, the network tariff appears as a component of the retail price. Retail prices are designed to include several types of supply costs: the energy component (i.e. the cost for the supplier to generate and/or purchase energy), the supplier's commercial costs, the network cost including transmission and distribution, the tax component to support public objectives, the VAT (Value Added Tax), particular charges to support RES, etc. As shown in Figure 10, depending on the country, the breakdown of the electricity bill widely varies: all other things being equal, if a given billing component varies, its relative impacts on the bill will be different depending on the country.

A similar discussion as the above one for network tariffs can also be made for retail prices, in particular for the energy part of the price, which, depending on the supplier's offer, may have different components, as

[38] In some countries, the awareness of this issue may lead to changes in the grid tariffs, e.g. in Austria the grid tariffs have been updated in order to significantly reduce the monthly capacity cost increase caused by negative frequency regulation provided to the TSO [254].

well as a time-based structure with different pre-defined prices for different pre-defined periods or possibly even dynamic pricing. These prices mainly aim to meet the supplier's objectives. The provision of flexibility services by MES may therefore increase the costs due to retail prices and again these have to be taken into account in the economic assessment to determine whether the MES will participate or not in the provision of flexibility services.

Imbalance settlement costs

For each settlement period, the imbalance settlement process settles the gaps between the contracted volume of electricity to be generated or consumed by a player and the electricity volume which the player actually generated or consumed. Indeed, if the actual generated or consumed electricity volume is higher or lower than the traded volumes, this may cause imbalances in the associated BRP portfolio and the BRP will have to pay imbalance costs accordingly. The imbalance pricing is reputed to be an efficient way to make the BRP improve its previsions and to better balance its portfolios in the day-head and intraday markets.

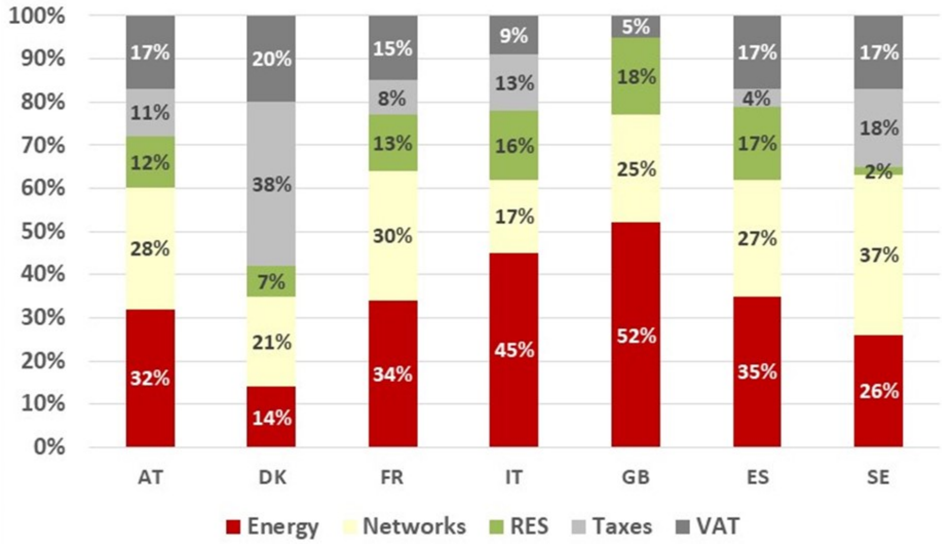


Figure 10 - Breakdown of incumbents' standard electricity offers for households in capital cities relevant to the MAGNITUDE project in Nov./Dec. 2017 (%) (based on ACER/CEER 2018 [184][39])

An interesting summary of imbalance settlement process is given in [185]: "*in practice, the time resolution (or settlement period) of the imbalance settlement and its trading products is consistent with that of the BRP's day-ahead commitment, i.e. ranging from hourly to quarter-hourly. Sometimes the settlement price also includes a multiplicative (e.g. Belgium, France) or additive punitive component (e.g. Germany) to strengthen incentives for BRPs to reduce own imbalances. Using the spot price as a reference, the settlement price tends to be higher for upward balancing (in the case of the system being short) and lower for downward balancing (in the case of the system being long). The imbalance settlement can be either based on a one-price system (e.g. Germany, Spain) or a two-price system (e.g. France, Italy)*". In a one-price system there is a single price for both positive and negative imbalances, whereas in the two-price or dual price

[39] Such a benchmark should always be considered with caution. For instance, measures supporting RES can be direct via specific green taxes and also partly indirect (i.e. integrated into another energy tax or in the network shares).

system there are two different prices, one for upward and one for downward imbalances (e.g. in France [186]). Several potential BRPs' strategies are proposed in [159] depending on the pricing system in place.

Some imbalance settlement designs could appear as a barrier for flexibility provision: for instance, a volume-weighted average imbalance pricing penalizes imbalances less than a marginal pricing, and therefore gives less incentive for BRPs to self-balance. Shorter settlement periods might also lead BRPs to schedule their assets with a finer granularity, flexibilities being used to balance BRPs' portfolio instead of being used ultimately by the TSOs within the balancing processes.

Changing existing rules could also have significant impacts on the system: a shorter imbalance period could induce increasing IT and metering costs; a marginal imbalance settlement pricing could generate a higher pricing volatility; etc.

Several key issues are thus presently being discussed in Europe, particularly regarding the harmonization of the rules between member States [187]. For instance, ENTSO-E [188] proposes to use a single imbalance price for all imbalances for each imbalance area and within an imbalance settlement period. The 2017 EC guideline on electricity balancing ("EBGL") [1] has established several arrangements:

- each TSO shall determine the imbalance price for each imbalance settlement period, its imbalance price areas and each imbalance direction,
- the imbalance price for negative (positive) imbalance shall not be less (greater) than, alternatively: (a) the weighted average price for positive (negative) activated balancing energy from frequency restoration reserves and replacement reserves; (b) in the event that no activation of balancing energy in either direction has occurred during the imbalance settlement period, the value of the avoided activation of balancing energy from frequency restoration reserves or replacement reserves.

4.2 Cross-sector issues

Gas system versus electricity system

There are a lot of similarities between the gas system and the electricity system. Both are unbundled and have:

- Transmission and distribution networks and the corresponding roles of transmission and distribution operators.
- Producers, suppliers, consumers, storage operators, balance responsible parties (BRP), market operators, etc.
- Day-ahead and intraday (or within-day) markets, as well as balancing markets.

However, the characteristics of the gas and electricity markets are rather different, both in terms of mechanisms and in terms of timings or time cycles. Additionally, like for the electricity system, the situation and the characteristics of the gas markets are rather heterogeneous between the case study countries. Increasing synergies between electricity and gas systems will require to take into account the market specificities of both sectors in the different considered countries. Innovative market design options for coupling electricity and gas sectors will be studied later in the project and recommendations for potential evolutions will be devised.

Focusing now on the gas sector itself, it appears that even though the process of market liberalisation is advancing, many hubs are not yet mature and well established. The only hubs that can be considered as mature are the TTF in the Netherlands[40] and the NBP in the UK[41] [189]. The Energy Roadmap 2050 of the European Commission [190] outlines "*the gas market needs more integration, more liquidity, more diversity of supply sources and more storage capacity*". Greater interconnectivity of the European networks is necessary as well as flexible underground storages and more network balancing [191]. However it must be mentioned that in some European countries, the future of natural gas is questioned for instance in the Netherlands[42].

Another market barrier is the gas supply dependency from Russia and Africa. Some countries like Denmark have adopted policies for reducing the gas consumption and fossil fuels consumption in general by increasing the efficiency of gas or fuel consumers and by increasing the renewable energy use which led to an import of fossil fuels of just 4% (data from 2015 [192]).

One of the main trading barriers are cross border tariffs between countries inside the EU [193]. Additionally, these tariffs are accumulated which results in higher costs for a trader that ships through several borders. It also is a barrier for more efficient cross-border balancing and it makes transportation routes less efficient. Market liquidity in Europe has been improving with "intense" competition at wholesale markets and "moderate" prices that are converging across the EU. Nevertheless, it is not yet a fully integrated single market.

Lack of coordination between gas and electricity network operators

Going further, the lack of coordination between gas and electricity network operators both at transmission and distribution levels can also be a barrier preventing the gas system from providing flexibility towards the electricity system. Increasing synergies between both sectors should not only be considered at market level but should also be investigated for network operation and sharing of technical knowledge and data. Gas and electricity network operators have rather different system culture and processes resulting from the different time constants, inherent resilience and dynamic behaviours of both types of networks. This should be taken into account.

Heat network versus electricity system

Like for the gas system, there are some similarities between the heat networks and the electricity system. For instance, both have:

- Distribution networks and sometimes even transmission networks (e.g. in the Copenhagen area in Denmark) and therefore the corresponding roles of distribution and transmission operators.
- The roles of producers, suppliers, consumers, storage operators, etc.

However, there is no unbundling in the heat sector. So, network operator roles can be carried out by players being also producer or supplier. For instance, the heat network operator can also be the heat supplier of the consumers connected to the district heating network, and the heat production plant owner can be

[40] The Title Transfer Facility (TTF) is a virtual market place to trade natural gas in the Netherlands via futures, physical and exchange trades.
[41] The National Balancing Point (NBP) is a virtual market place to trade natural gas in the United Kingdom.
[42] In the Netherlands (which has been a major gas producer for a long time in which virtually all houses are connected to the gas grid), a gas-free future within 2050 is now debated [252]. A national target has been set to ensure one in four Dutch homes no longer relies on gas for heating or cooking by 2030. The Dutch government also announced in March 2018 it would stop the gas extraction at Groningen by 2030 for safety reasons (earthquake risk).

either the district heating network operator itself or have a supply contract with the district heating operator.

In the heat sector there are generally no "organised" markets as such, even though, some sorts of "heat market" mechanisms can sometimes be found involving a day ahead planning and intraday adjustments between the heat producers and the operator of the mechanism as shown in Section 3.3.5 for Denmark. Indeed, the existence of a cohesive set of DH networks in the Copenhagen area made it possible to settle a kind of organized market between buyers (DH operators) and producers (CHP plant owners). This market is based on marginal net heat costs, which directly depends on power sales determined by the Nordpool market. However, this market works because there is a large cohesive DH network where heat plant owners are distinct from the DH owner and operators.

Regarding operation aspects, the characteristics of the heat and electricity networks are very different in terms of time constants, resilience and dynamic behaviours, and therefore the associated operation needs and requirements also differ a lot.

Increasing synergies between heat networks and the electricity system will require to take into account all the specificities of both systems at the local scale. Indeed, heat networks are inherently local systems and rather different situations can be met from one area to the other.

Risk of incompatibility between RES/waste supports and the provision of flexibility services[43]

Although it might not be intuitive, regulation fostering a high share of RES/waste or heat recovery in district heating sector might have an adverse effect on the exploitation of multi-energy-based flexibility. Through the provision of flexibility to the electricity system, the MES could exceed or on the contrary come below certain thresholds that allow to benefit from support mechanisms, reduction of fees, derogation, etc. They would then lose these advantages. For instance, in France, maximising the synergy and flexibility opportunities (with electricity and gas networks) might lower the share of RES used by a district heating network under the threshold of 50%, which might exclude this district heating network from several support measures (e.g. reduced VAT in France) and harm its economic profitability and stability. In Germany, waste heat still suffers from the competition with other energy solutions (lower gas prices for example). It could be relevant to ensure that future regulations concerning district heating take into account the added value of these synergy opportunities from a multi-energy system point of view.

Contrasted potential for CHP and for heat pumps

Regardless of technical aspects, potential opportunities to couple MES with other markets appear still significant for heat to power technologies given the current important CHP deployment: it is already possible to generate electricity at a large scale with CHPs, provided that the heat demand is met (i.e. power generation is driven by heat demand).

But these opportunities presently seem much more limited for power to heat technologies such as heat pumps: in this case, the MES could provide services by consuming electricity opportunely with the heat pumps. But this will require a large amount of heat pumps, which is far from being the case, due to the limited heat pump deployment in most European countries, excepted in Sweden and Denmark.

Denmark is indeed a good example of the development of both types of technologies: it has seen an increased penetration of decentralized CHP. Regulation has supported the adoption of CHP units by

[43] Note that similar issue may also exist with CHP supporting schemes.

allowing aggregations of those units to bid in the Danish electricity markets. Analysis showed the economic viability of using electric flexibility from CHP units for national balancing purposes and therefore improving the overall integration of wind power [194]. Together with heat storage, CHP can provide optimal dispatch of their cogeneration of electricity and heat into the electricity market: for instance during a period of high wind power and low electricity prices, CHP can decrease the need for power generation and meet heat demand through the heat storage. In 2013, the electricity tax was significantly reduced, resulting in an incentive to generate heat through electric boilers and heat pumps [195] and therefore leading to the deployment of heat pumps.

Different repartitions of fixed and variable costs from MES to MES

For a MES, a large share of fixed costs – related with up-front and maintenance cost – reduces the gain opportunity in trading of between alternative energy sources for heat generation. The decision is however relevant only at a local scale, i.e. for each case study. In fact, operating and maintenance costs vary widely depending on the type of heating networks. This repartition of variable and fixed costs is specific to each MES: it could significantly influence the interest of each MES to provide flexibility or not (e.g. to generate or to buy electricity to run its heat pumps).

Potential contractual limits for MES

A MES is initially designed and sized for supplying contracted energy services (heating, cooling, etc.): such energy services will remain its primary objectives. Their ability to offer flexibility to mechanisms such as capacity requirement mechanisms, balancing or ancillary services might be limited by these contractual commitments that will then become constraints for flexibility provision.

A large diversity of stakeholders with deeply different professional culture

Depending on their purposes and types, multi-energy systems may involve a large diversity of stakeholders and a complex system of contracting, agreement and interactions between them. The feasibility of multi-energy-based flexibility provision to the electricity system can be hampered by the additional contractual complexity that it will bring. At the local scale, this could generate high learning and transaction costs in fields not well-known by the MES operator.

At a larger scale, the traditional culture to invest, plan, maintain, operate and remunerate is rather different in the three sectors (gas, electricity and heating/cooling), in particular for the heat sector. Increasing synergies between the three sectors will definitely require evolutions which will depend on the willingness of the stakeholders, their awareness of the stakes and the potential benefits they can make. Nevertheless, this might generate high learning and implementation costs in order for MES to provide their flexibility to the electricity system.

5 Conclusions

In this deliverable, starting from the analysis of the main needs of the electricity system, the most relevant services that could be provided by multi-energy systems (MES) have been selected using the following criteria, namely services:

- that allow to increase the share of Renewable Energy Sources (RES), avoid curtailment of variable RES, enhance the security of supply,
- for which the enhancement of the synergies between electricity, heating/cooling and gas systems provide real opportunities,
- for which the first elements already collected by the project (technical, regulatory, market design) show a potential value for the provision by MES.

They are given in Table 18 below.

Table 18 - Selected relevant services and associated electricity system needs

Needs	Services
Frequency control and balancing	FCR (Frequency Containment Reserve)
	aFRR (Automatic Frequency Restoration Reserve)
	mFRR (Manual Frequency Restoration Reserve)
	RR (Replacement Reserve)
	+ Dedicated additional balancing mechanisms which may exist in certain countries.
Energy trades	Day ahead energy trades/market
	Intraday energy trades/market
System adequacy	Capacity requirement mechanisms
Congestion management at transmission and distribution levels	Re-dispatching mechanisms or active power control

It should be noted that, in the electricity system, the enhancement of the synergies between electricity, gas and heating/cooling systems will mainly have an impact on “energy” or active power. Therefore, the most relevant services are indeed those services linked to active power.

In a second step, the mechanisms for the procurement of these services have been described and compared in the seven case study countries considered in the MAGNITUDE project (Austria, Denmark, France, Great Britain, Italy, Spain and Sweden).

Regarding energy trades, because of the day-ahead and intraday energy market coupling mechanisms that are already in place in Europe, the major processes for the organisation of both types of energy markets are already similar in the considered countries, even if going further in the analysis, some country specificities can be found, regarding for instance the timelines involved, the product duration, etc.

For the other selected services, a larger diversity is observed in the 7 considered countries, and it is even truer for the capacity requirement mechanisms, which may take very different forms (organised markets, capacity payments, reserves) and even do not exist in some countries.

However, some initiatives have been launched by TSOs and are on-going in order to harmonize the procurement of balancing and frequency regulation services and support the implementation of the EC Guideline on Electricity Balancing [1], such as the FCR cooperation, the PICASSO project for aFRR, the MARI project for mFRR, and the TERRE project for RR [2].

In a third step, the gas and heat sectors have also been described for the 7 case study countries, to the extent that they will be affected by such provision of services to the electricity system.

For the gas sector, like for the electricity system, although similarities can be found, the characteristics of the gas markets are rather heterogeneous between the case study countries, for instance in terms of trading times, retail tariff structures, balancing mechanisms, etc. This is even truer for the heat sector, where a large diversity of situations, organisations and mechanisms can be observed in the different countries. Contrary to the electricity and gas sectors, there is no unbundling in the heat sector. So, the heat network operator role can be carried out by players being also the heat production plant owner and/or the heat supplier of the consumers connected to the district heating network. In the heat sector, there is generally no “organised” markets as such, even though, some sorts of heat market mechanisms can sometimes be found involving a day ahead planning and intraday adjustments between the heat producers and the operator of the mechanism, like for the integrated heat market implemented in the Greater Copenhagen area in Denmark.

Comparing the roles involved in the electricity, gas and heating/cooling systems, there are a lot of similarities. Indeed, the three sectors have:

- Distribution networks and transmission networks (mainly distribution networks for the heat sector but transmission networks can sometimes be found like in the Copenhagen area in Denmark) and therefore the corresponding roles of distribution and transmission network operators.
- The roles of producers, suppliers, consumers, storage operators, etc.
- A balancing requirement between generation and consumption and therefore the associated balancing responsible role.
- Metering-related roles, etc.

These similarities will undoubtedly help in the enhancement of the synergies between the three sectors.

However, regarding operation and market aspects, the characteristics of the electricity, gas and heat networks are rather different in terms of time constants, inherent resilience and dynamic behaviours, and therefore the associated operation needs and requirements also differ considerably.

Finally, potential market and regulatory barriers or shortcomings have been discussed. The following main categories have been identified:

- The diversity of situations, market mechanisms and rules that can be found in the considered countries, namely diversity between countries and between electricity, gas and heat sectors.
- Specific rules or requirements preventing or limiting the provision of services by MES.
- Additional or increased costs that may be caused for instance by network tariffs, retail prices, imbalances, or inherent fixed and variable operation costs of MES.
- Insufficient attractiveness of flexibility services remuneration to cover all the costs incurred.
- Lack or incompatibility of incentive schemes: for instance to encourage DSOs to procure flexibility services, or between RES support schemes and the provision of flexibility services.

- Lack of coordination between network operators: between DSOs and TSOs in the electricity system, and/or between electricity, gas and heating/cooling network operators.
- The large diversity of stakeholders with deeply different professional culture, implying both: (i) complexity and numerous interactions/transactions, and (ii) needs for awareness raising, learning and training.

Increasing synergies between electricity, gas and heating/cooling systems will therefore require to take into account the specificities of the three sectors both at the national and local scales. Indeed, it should be kept in mind that heat networks are inherently local systems and rather heterogeneous situations can be met from one area to the other and from one MES to the other.

This deliverable has provided a description and comparison of the main characteristics of the procurement mechanisms for the selected services in the seven case study countries. These results are then used in other work packages of MAGNITUDE for instance to:

- carry out a qualitative assessment of the technical capabilities of the technologies involved in the case studies to provide the selected services,
- identify the services that will be further studied and simulated for each case study and to define the project use cases,
- guide modelling and development choices to be made for the project use cases.

This characterisation will also be further completed with detailed targeted information collected to study the use cases defined for each case study.

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7 APPENDICES

7.1 Electricity

This appendix provides the information and data collected on the provision of the relevant selected services in the 7 case study countries (Austria, Denmark, France, Italy, Spain, Sweden, and Great Britain).

More specifically the following sections provide detailed information on the provision mechanisms for:

- the day-ahead energy markets in Section 7.1.1 and Table 19,
- the intraday energy markets in Section 7.1.2 and Table 20,
- the capacity requirement mechanisms in France, Great Britain and Italy, in Section 7.1.3 and Table 21,
- the Frequency Containment Reserve (FCR) in Section 7.1.4 and Table 22,
- the Automatic Frequency Restoration Reserve (aFRR) in Section 7.1.5 and Table 23,
- the balancing mechanisms, manual Frequency Restoration Reserve (mFRR) and Replacement Reserve (RR) in Section 7.1.6 and Table 24.

7.1.1 Day ahead energy markets

Table 19 - Characteristics of the day ahead energy markets in the case study countries

	Austria	Denmark	France	Italy	Spain	Sweden	Great Britain
Market participants	Producers, suppliers, large consumers, traders and brokers						
	Aggregators allowed	Aggregators allowed	Aggregators allowed	Aggregators are not allowed at the moment but will be introduced in the next future.	Aggregators allowed	Aggregators allowed	Aggregators allowed
Type of participation	Voluntary participation. Market participants must be registered. Sometimes passing an exam is required. They must be a BRP or have to be part of the portfolio of a third party BRP (in some countries).						
	Must be registered as a BRP with a balancing group. Formal BRP requirements for legal entities and natural persons are defined by e-control.	Must be a BRP or be part of the portfolio of a third party BRP.	Must be a BRP or be part of the portfolio of a third party BRP.	Must be a BRP or be part of the portfolio of a third party BRP.	Mandatory participation for those producers registered in the administrative register of electrical energy production plants. Participants must be registered as a BRP with a balancing group		
Selection • **Eligible technologies** (generation, demand, storage)	Open	Open	Open	Not open for storage But storage will be allowed in the next future	Open	Not open for storage	Open

	Austria	Denmark	France	Italy	Spain	Sweden	Great Britain
• **Min. and max. volumes**	Minimum volume increment is 0.1 MW for individual hours and 0.1 MW for blocks						
	-	Maximum volume for block order is 500 MW	-	-	-	-	-
Products traded • **Type of product**	Unidirectional						
	-	Maximum amount of block orders: 50 per trading portfolio	-	-	-	-	-
• **Deployment duration of the product**	Hourly products (1h) Standard block orders User defined blocks Smart block bids 15 min products possible	Hourly products (1h) Block orders (several hours)	Hourly products (1h) Pre-defined standard block orders User defined blocks	Hourly products (1h)	Hourly products (1h) Standard block orders User defined blocks	Hourly products (1h) Block orders	Half hourly products (30 minutes) Hourly products (1h) Block orders
Remuneration	Market price pay-as-clear						
	Prices must be between -500 €/MWh and 3000 €/MWh.	Prices must be between -500€/MWh and +3000€/MWh	Prices must be between -500€/MWh and +3000€/MWh	Price between 0€/MWh and 3000€/MWh. In the future, prices allowed will be between -500€/MWh and 3000€/MWh	Energy price between 0€/MWh and 180,38€/MWh	Energy price	Price must be between -500€/MWh and 3000€/MWh. Payment for delivered energy €/MWh

7.1.2 Intraday energy markets

Table 20 - Characteristics of the intraday energy market in the case study countries

	Austria	Denmark	France	Italy	Spain	Sweden	Great Britain
Market participants	Producers, suppliers, large consumers, traders and brokers						
	Aggregation allowed	Aggregation allowed	Aggregation allowed	Aggregators are not allowed at the moment. The future market reform will consider the aggregator role.	Aggregation allowed	Aggregation allowed	Aggregation allowed
Type of participation	Voluntary participation. Market participants must be registered. Sometimes passing an exam might be required. They must be a BRP or have to be part of the portfolio of a third party BRP (see day-ahead energy market).						
Selection • **Eligible technologies** (generation, demand, storage)	Open	Open	Open	Open	Open	Not open for storage	Open
• **Min. and max. volumes**	Minimum volume increment is 0.1 MW.						
	-	-	-	-	-	-	Maximum is 2000 MW.
Products traded • **Type of product**	Unidirectional						
• **Time cycle**	Continuous trading 7 days a week and 24 hours a day. For hourly products: starting at 15:00 on the current day, all	Continuous trading 7 days a week and 24 hours a day. At 14:00 CET, capacities available for Nord Pool's	Continuous trading 7 days a week and 24 hours a day. Each hour or blocks of hours can be traded	Seven implicit auctions: 12:55 to 15:00 on D-1 12:55 to 16:30 on D-1 17:30 to 23:45 on D-1	Hybrid scheme. Structured into six sessions in the MIBEL area opening at 17:00, 21:00, 01:00, 04:00, 08:00 and	Continuous trading 7 days a week and 24 hours a day. At 14:00 CET, capacities available for Nord Pool's	Continuous trading 7 days a week and 24 hours a day Tradable contracts open 2 days before delivery.

	Austria	Denmark	France	Italy	Spain	Sweden	Great Britain
	hours of the following day can be traded until 5 minutes before delivery begins. For 15-minute products: starting at 16:00 on the current day, all 15-minute periods of the following day can be traded until 5 minutes before delivery begins.	intraday trading are published. Trading takes place every day around the clock until one hour before delivery.	until 5 min before delivery begins Starting at 15:00: all hours of the following day can be traded.	17:30 on D-1 to 3:45 on D 17:30 on D-1 to 7:45 on D 17:30 on D-1 to 11:15 on D 17:30 on D-1 to 15:45 on D With D: day of delivery and D-1: day before the day of delivery	12:00 and closing respectively 45 minutes later. Continuous trading on the European cross-border intraday market.	intraday trading are published. Trading takes place every day around the clock until one hour before delivery.	Closure of trading: 15 minutes before deliver for half-hourly products, 16 minutes before delivery for hourly products, 17 minutes before delivery for 2-hour blocks and 19 minutes before delivery for 4-hour blocks.
• **Deployment duration of the product**	15-min products Hourly products (1h) Standardised blocks of hours User defined blocks	15-min products Half-hourly products (30 min) Hourly products Blocks of hours (up to 24 hours)	Hourly products Standardised blocks User defined blocks	Hourly products	15-min products Hourly products (1h) Standardised blocks of hours User defined blocks	15-min products Half-hourly products (30 min) Hourly products Blocks of hours (up to 24 hours)	Half-hourly products (30 min) Hourly products 2 hours blocks 4 hours blocks
Remuneration	Market price “pay-as-bid” Price range between -9999.99€ to 9999.99€	Market price “pay-as-bid”	Market price “pay-as-bid” Payment for delivered energy €/MWh. Price range between - 9999€ to 9999€.	Market price “Pay-as-clear” Currently allowed prices are in the interval 0€ to 3000€. In the future, the interval will be -500€ to 3000€.	Market price “Pay as clear” for the auctions Market price “pay-as-bid for continuous trading Price range between 0€/MWh and 180,3€/MWh	Market price “pay-as-bid	Market price “pay-as-bid”. Payment for delivered energy with a minimum price increment of 0.01 GBP/MWh. Price range between -500 GBP to 3000 GBP.

7.1.3 Capacity requirement mechanisms [17]

In this section, the characteristics of the capacity requirement mechanisms are given for France and Great Britain in Table 21, and for Italy later in the text. The mechanisms for Spain and Sweden are described in Section 3.1.3. There is no capacity mechanism in Austria and in Denmark.

Table 21 - Characteristics of the capacity requirement mechanisms in the case study countries

	France [29] [28] [25] [26] [27]	**Great Britain** [30] [31] [32] [33] [34]
Types of mechanisms	Decentralized auction-based mechanism, with market participants contracting directly between themselves. Purchase obligations of capacity certificates for retailers, large consumers not served by a retailer and transmission and distribution grid operators (as buyers of the gird losses) Capacity certification for generators and operators of load curtailments (valid for one year) Started in Jan. 2017	Centralized mechanism relying on an auction-based market where capacity providers make their bids and the TSO procures the capacity. Demand response bids can temporarily compete into a dedicated mechanism called Transitional Arrangements. 1st auction in December 2014 for 2018/19 **CAVEAT**: following a judgment of the General Court of the European Union in November 2018 removing the European Commission’s approval of the state aid for the GB Capacity Market scheme [35], a standstill period has been introduced until it can be approved again. The UK Government is carrying out a consultation on potential evolutions of the mechanism [36] [37].
Providers	Producers, aggregators and demand response (operators of load curtailment capacities - "*exploitants de capacités d'effacement*", including large industrials and demand-side operators), only if their capacities are certified Participation of cross-border offers expected in 2019 or 2020.	After a pre-selection process, new and existing power generation plants, electricity storage plants, demand response. A distinction is made between proven demand response (already certified via another mechanism), and unproven demand response (not yet certified). From 2015, participation of interconnectors
Open to aggregation	Mandatory aggregation below 1 MW Aggregation allowed below 100 MW Aggregation not allowed above 100 MW Aggregation of demand response accepted.	Aggregation of demand response and generation accepted *“Limited aggregation of small generation and loads is allowed, as long as separately metered units do not have a capacity of over 2MW”* *“Only generating units of the same type can be aggregated”*
Type of participation	Mandatory for buyers of capacity as defined above Voluntary for generators < 3GW and operators of load curtailments (demand response) Mandatory for generators > 3 GW	Voluntary

	France [29] [28] [25] [26] [27]	**Great Britain** [30] [31] [32] [33] [34]
Eligible technologies	Technology neutral Generation, storage, demand response Equal treatment of new and existing power plants	Technology-neutral Accepted technologies: existing generation, future planned generation, storage, proven demand response (already certified via another mechanism), and unproven demand response (not yet certified) **BUT** units that already benefit from another kind of support are not authorized to compete. In particular, the following are not accepted: • units with low carbon support (Feed-in-Tariffs, Contracts for Difference, etc.) • with long term STOR (Short-Term Operating Reserve) contracts
Thresholds	Minimum of certification = 1 MW Capacity guarantee (or one capacity certificate) = 0.1 MW	
Types of products	Unconditional delivery Unidirectional product Operators must ensure the effective availability of their capacities during *PP2 days* (checked by RTE, French TSO)	Providers with capacity agreements must deliver energy in periods of system stress announced by the TSO NGT, or face penalties Possibility to provide more than needed (with over-remuneration)
Fixed volume or volume range	Certified capacity: • to be certified, the capacity provider declares three elements: its capacity available to be activated during PP2 * Kj * Kh, with Kj to reflect its daily constraints, and Kh, to reflect its weekly constraints • The ability of each capacity to be activated is taken into account (period, duration…) • Expected availability: introduction of a reference value linked to the capacity type (gas: 88%, solar: 5%, etc.) • Possibility to re-adjust the certified capacity before the delivery period Verification of the capacity: the capacity is certified based on self-declared data submitted by the capacity providers. It can be tested by RTE from year Y-4 to year Y-1 and during the delivery year Y.	The capacity that a unit may bid into the auction corresponds to its installed capacity multiplied by a **de-rating factor**, depending on its technology (Demand response, storage, gas, solar, wind, nuclear…) Capacity providers which have secured a Capacity Agreement at the auction must deliver their capacity obligation at times of System Stress, or face a financial penalty. In case of a System Stress Event (see below), the ALFCO (see below) is modulated with underlying system demand for electricity: it ensures that the capacity obligations will be "load following", meaning that providers are required to deliver a percentage of their obligation that is proportional to the percentage of the demand at the time of the stress event (same effort for all participants; not individual efforts).
Tolerance	Introduction of an acceptability margin: gas +/- 10%, biomass +/- 10%, nuclear 90%, onshore / offshore wind farm 20%-25%, solar 5%...	

	France [29] [28] [25] [26] [27]	**Great Britain** [30] [31] [32] [33] [34]
Time cycle	Capacity certificates can be traded from the 1st of January of year Y-4 to 15th of December of the year Y+2. Buyers and sellers trade capacity certificates (also called capacity guarantee) at the capacity market auction sessions carried out each year (6 sessions in 2018) or by OTC. Delivery on year Y with two sub-periods: from 1st of January to 31th of March; from 1st of November to 31th of December. Certified capacities must be available to be activated during 10 to 25 days per delivery period ("PP2 days"), corresponding to winter peak days PP2 days are not defined in advance. RTE indicates each PP2 day the day before.	Competitive auction organized 4 years ahead the delivery period, with a subsequent auction held one year ahead Delivery period: from 1st of October of year Y to 30th of October of year Y+1. If a System Stress Event is forecasted by NGT (anticipated margin < 500 MW), NGT sends the same Capacity Market Warning (CMW) to all capacity providers. At this stage, the CMW is just a signal without any consequence A System Stress Event (SSE) is declared if, at least four hours after the CMW, the SO instigates a Demand Control Instruction lasting for a period greater than 15 min. If such a SSE is declared, each provider must deliver sufficient electricity to meet its Adjusted Load Following Capacity Obligation (ALFCO, MWh), i.e. the volume described in its Capacity Agreement
Deployment duration	The certified capacity must be available during each PP2 day (announced the day before by RTE) PP2 days are weekdays in winter and cover 10 hours per day (from 7 AM to 3 PM and from 6 PM to 8 PM). There are from 10 to 25 PP2 days per delivery period between November and March. A priori, PP2 days can be consecutive days Energy delivery through contracts and/or bids on the energy markets and bids on the balancing market.	A priori, more than 30 minutes. A priori no limitation on the number of activation and on the duration between two activations.
Remuneration	For yearly auction: pay-as-clear pricing (€/MW) with price caps (20 k€/MW in 2017; 40 k€/MW in 2018 & 2019…) Example of prices in 2017: 9999,8 €/MW or 999,98 €/certificate	Pay-as-clear [£/MW) but with price caps (75 £/kW for new units; 25 £/kW for existing units) Examples of prices: • Auction 12/2014 for delivery 2018/19: 19,4 £/MW • auction 12/2015 for 2019/20: 18 £/MW • auction 12/2016 for 2020/21: 22,5 £/MW • early auction 02/2017 for delivery 2017/18 (auction not planned initially): 6,95 £/MW This market-based price is paid during one year for existing units and demand response bids, during 3 years for refurbished units, during 15 years for new units. Over-delivery Payment ex post is possible if the effective provision of a provider exceeded his capacity obligation (payments covered by the penalties paid by defaulting providers over the period) Penalties if the provider is not able to deliver during the system stress event, capped at 100% of a capacity provider's annual Capacity Market payment with respect to a Capacity Market Unit.

Italy

A project of Capacity Requirement Mechanism sharing a lot of similarities with the British one is envisaged. This project has been authorized for 10 years by the EC (07/02/18) and should be implemented soon. Its main expected characteristics are as follows.

The participation would be voluntary and the capacity providers would be existing, refurbished or new capacity including generation (conventional and renewables), storage assets and demand response. The participating units would have to relinquish other subsidies for the amount of capacity contracted and demand response would have to meet the qualification requirements for the ancillary service market (MSD). The participants who would be awarded the capacity payment would commit to offer their capacity in the Italian day-ahead market (MGP) in each hour of the delivery period.

In the full Implementation phase, the mechanism would consist of a descending clock auction organized four years before the delivery period, complemented with adjustment auctions in Y-3, Y-2 & Y-1 with a delivery period of one year, to permit to the capacity market participants to adjust their offers (three years and one year ahead of the delivery period).

Price: pay-as-clear (€/MW:year).

With a remuneration over 15 years for new units and over 3 years for existing units.

Two caps have been proposed:

- in the range of 75-95k€ /MW/year for a new unit,
- in the range of 25-45k€ /MW/year for an existing unit

The capacity providers would have to pay a penalty if the awarded capacity is not available during shortage events (3000 €/MWh).

7.1.4 Frequency Containment Reserve (FCR) [55] [45]

Table 22 - Characteristics of the FCR mechanisms in the case study countries

	Austria [196]	**Denmark,** [197] [198] [199] [200]	**France** [201] [202]	**Italy** [203] [204]	**Spain** [205] [206] [207]	**Sweden** [200] [197]	**Great Britain,** [208] [209] [210] [211] [212] [213] [60]
Names of mechanisms	FCR (Primärregelung)	In the Western-DK1 zone: FCR In the DK2 zone: • FCR-N (with N for normal operating band within 49.90 Hz < f < 50.10 Hz) • FCR-D (with D for disturbances for larger frequency deviations below 49,90 Hz)	FCR	FCR	FCR (Reserva de regulacion primaria - primary regulation reserve)	FCR-N (with N for normal operating band within 49.90 Hz < f < 50.10 Hz) FCR-D (D for disturbances for larger frequency deviations below 49,90 Hz) (more details after the table)	**FFR** = Firm Frequency Response, as a firm volume expected to be stable **MFR** = Mandatory Frequency Reserve, for the remaining need, as a more volatile volume accessed in the balancing market closer to real time **EFR** (new) = Enhanced Frequency Response (tender in 2016). Dynamic service where the active power changes proportionally in response to changes in system frequency. Investigation are still on-going on new faster-acting frequency response **FCDM** (Frequency control by demand management), mentioned as FCR in [45]
Providers and eligible technologies	Producers only with plants in operation Batteries Consumers, which can fulfil the requirements (unusual) No restriction for technologies	Generation based resources Load based resources Energy storage based resources	Generators Some large consumers (injection & withdrawals), either connected to the transmission grid (tests prior to connection) or FCR-certified Pump Storage units pumping	Non-intermittent generating units > 10 MV, meeting the requirements formulated in Chapter 1 of the Italian Grid code (no obligation for non dispatchable renewables)	Generators only by speed shifters	Generators only	**MFR**: transmission-connected generators via the connection agreement capability: • NGT: small < 50 MW, medium: 50-100 MW, large: > 100 MW • Scottish Power: small < 30 MW, large: > 30 MW • Scottish Hydro Elec: small < 10 MW, large: > 10 MW **FFR**: unlike MFR, open to balancing mechanism unit

	Austria [196]	**Denmark,** [197] [198] [199] [200]	**France** [201] [202]	**Italy** [203] [204]	**Spain** [205] [206] [207]	**Sweden** [200] [197]	**Great Britain,** [208] [209] [210] [211] [212] [213] [60]
							(BMU) and non-BMU providers, existing MFR providers and new providers; storage accepted **FCDM**: interruption of supply to parts of consumer loads which have contracted to offer this service in case of large deviations (bilateral contract).
	Aggregation over different balance groups is allowed	Demand response, aggregated demand response and aggregated generation accepted [45]	Demand response, aggregated demand response and aggregated generation accepted through the FCR cooperation (with DE, AT, CH & NL) [45]	No aggregated load and no aggregated generation accepted [45]	No demand response and no aggregated demand response [45]	Demand response, aggregated demand response and aggregated generation accepted in FCR-N and FCR-D [45]	Demand response, aggregated demand response and aggregated generation accepted for FFR and EFR [45]
Maximum volume	Prequalified power (physical limit of unit)		2,5 % PMax Max. primary reserve per unit = 150 MW	Obligation to supply not less than: • 1,5% of the total installed power in the continental Italy • usually 1,5 % in Sicilia but 10% in case of saturated interconnections • 10 % in Sardinia			Firm Frequency Response: > 1 MW EFR: max = 50 MW
Minimum offer	Minimum offer +/- 1MW Minimum **bid** increments of full MW	DK1 zone: 0,3 MW DK2 zone: 0,3 MW for both FCR-N and FCR-D Minimum **bid** increments: - FCR-N: 0,1 MW	Minimum offer: +/- 1 MW Mandatory aggregation if below 1 MW Minimum bid increments of 1 MW	Data not available (ENTSO-E [55])	Data not available (ENTSO-E [55]) [45] mentions minimum bids for balancing and anscillary services > 5 MW and 90 MW for	0,1 MW for both FCR-N and FCR-D	FFR: at least 1 MW (10 MW before 04/2017); EFR: > 1 MW FCDM: > 3MW (multiple aggregated sites accepted)

	Austria [196]	**Denmark,** [197] [198] [199] [200]	**France** [201] [202]	**Italy** [203] [204]	**Spain** [205] [206] [207]	**Sweden** [200] [197]	**Great Britain,** [208] [209] [210] [211] [212] [213] [60]
		- FCR-D : 1MW			interruptible contracts with REE		
Types of products	Symmetrical Availability of the total volume over one full week, from the Monday 00h00 to Sunday 24h00 Automatic activation Percentage of primary control reserve activated depending on the frequency deviation amount	Does not need to be symmetrical FCR-N: the supplier can submit bids hourly or as block bids. Block bids submitted at the auction two days before the day of operation (D-2) may have a duration of up to six hours. Block bids submitted at the auction the day before the day of operation (D-1) may have a duration of up to three hours	Symmetrical Availability of the total volume over one full week, from the Monday 00h00 to Sunday 24h00 Automatic activation For each activation, requested capacity calculated by the TSO as a percentage of the reserved capacity	n/a	Symmetrical	Symmetrical	Symmetrical
Ramping or response time (slopes)	Delivery of 50% after 15 s and 100% must be attained within 30s after the occurrence of the frequency deviation Maximum activation in case of frequency deviation > 200 mHz ±10 mHz of dead band 5 mHz precision of f-meter	Zone DK1: delivery of 100% within 30s Zone DK2: FCR-N: 100% within 150s after frequency step change of ± 0,1 Hz FCR-D: 50% within 5s and 100 % within 30s	Ability to deliver 50% of the expected power variation within 15s and 100% within 30s If deviation > 200 mHz, ability to deliver the maximum primary power declared to RTE	Every generation group must be equipped with a speed regulator whose load reference signal can be varied from 0% to 100% of the nominal load in a maximum time of 50s	If imbalance > 1500 MW (perturbations between 100 and 200 mHz), delivery of 50% within 15s and 100% within 30s If imbalance <1500 MW (perturbations smaller than 100 mHz), delivery within 15s.	FCR-N: delivery of 63% in 60s; 100% in 3 min FCR-D: 50% within 5s; 100% within 30s	**MFR & FFR** Primary: full output within 10s Secondary: full output within 30s High frequency reserve: response within 10s **EFR:** be able to deliver a dynamic response, reaching 100% of the proportionate active power output within 1s of a frequency deviation **FCDM:** notification time = 2s (SEDC [45])

	Austria [196]	**Denmark,** [197] [198] [199] [200]	**France** [201] [202]	**Italy** [203] [204]	**Spain** [205] [206] [207]	**Sweden** [200] [197]	**Great Britain,** [208] [209] [210] [211] [212] [213] [60]
Deployment duration	Sustained for at least 30 minutes No limit between two activations	n/a -:	Sustained for at least 15 min	n/a	Sustained for at least 15 min until the secondary control recover its initial values	n/a	**MFR & FFR** Primary response (upward) sustained for a further 20s Secondary response (upward) sustained for 30 min High frequency response (downward) sustained indefinitely **FCDM**: interrupted supply for a maximum of 30 minutes
Number of activation per period	No limit	**DK1**: frequent activations **DK2: n/a**	Continuously	n/a	**n/a**	n/a	**FFR**: Pre-default dynamic continuous Pre-default static around 11 times per year **EFR**: continuous operation **FCDM**: around 11 times per year
Type of participation	Voluntary participation to an organised market (no obligation for grid users to offer) If there are not sufficient bids on the market, the TSO can force participation of qualified units	Voluntary participation to an organised market (no obligation for grid users to offer)	Mandatory provision via capacity reservation for new generation units > 40 MW and for existing generation units > 120 MW, as described in their connection agreement Not mandatory for unpredictable units Voluntary for others if FCR-certified	Mandatory provision without capacity reservation for dispatchable units for generators > 10 MW (no obligation for renewables)	Mandatory provision via capacity reservation	Voluntary participation to an organised market (no obligation for grid users to offer)	**MFR**: mandatory for transmission-connected generators as a condition of connection if: • NGT: > 100 MW • Scottish Power > 30 MW • Scottish Hydro Elec: > 10 MW **FFR**: voluntary **FCDM**: voluntary

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Type of selection	Since mid-2013 APG procures its Primary Control Reserves together with the Swiss TSO Swissgrid. Extended in 2015 to TSOs of Germany and The Netherlands, then to the Belgian TSO (2016) and French TSO (01/2017) based on TSO-TSO model Weekly process, to rank bids according to prices. Bidding period for the provision of primary control power in the following week is normally from Friday, 12:00 to Tuesday, 15:00	FCR-N: procurement through daily auctions in collaboration with Svenska Kraftnät (SE). FCR-D: procurement through daily auctions by Energinet and Svenska Kraftnät. Part of the requirement is procured two days before the day of operation (D-2), the remaining on the day before the day of operation (D-1).	Since 01/2017, contracts made via **the** weekly cross-border tendering process with GER, NL, BEL, SWI & AUS (merit order) (Expected evolution: daily tender with 6 x 4h slots from September 2019)	Monthly auctions. No more data available	Organised market for primary control TSO allocates before 31th October each year the primary control requirements		**MFR**: obliged generators submit prices for holding payments on a monthly basis via monthly auctions (FRPSS or Frequency Response Price Submission System). Some MFR volume will be entered into the FFR weekly auction trial starting in June 2019 **FFR**: competitive process via a monthly electronic tender process. Possibility to tender in for a single month or multiple months. A weekly auction trial will start in June 2019 **EFR**: via a tendering process (1st in July 2016; 200 MW procured) **FCDM**: bilateral contracts between potential providers and NGT
Remuneration	Pay-as-bid approach In case of failure by negligence, payment of a contractual penalty and compensation In case of repeated failures, APG has the right to terminate the framework agreement	Pay-as-bid principle	Pay-as-bid for reservation (€/MW/h) Based on a reference spot price for activation (€/MWh) since 2016 Verification via planned or non-planned tests + data collected by RTE via the metering system: financial penalties in case of failures	No remuneration at all. But for providers who accept to install a specific tool provided by the TSO there can be a possibility to be remunerated with prices set by Day Ahead Market. Optional remuneration mechanism for the contribution to primary frequency regulation if respect	Reservation not remunerated Service not remunerated in explicit terms. If an increment of the generated energy is needed, that energy will be sold in the market as usually but without any additional remuneration	Pay-as-bid	**MFR**: pay-as-bid • Holding payment (£/h) for the capability to provide response • Response energy payment (£/MWh) for the amount of energy delivered **FFR**: Payment: availability fee for the hours for which a provider has tendered to make the service available for (£/hr) Optional fees: • Nomination fee (£/hr) • Window initiation fee (£/window)

	Austria [196]	**Denmark,** [197] [198] [199] [200]	**France** [201] [202]	**Italy** [203] [204]	**Spain** [205] [206] [207]	**Sweden** [200] [197]	**Great Britain,** [208] [209] [210] [211] [212] [213] [60]
			beyond certain thresholds (Expected evolution: pay-as-clear in 2019)	the A.73 "Specifiche tecniche per la verifica e valorizzazione del servizio di regolazione primaria di frequenza"			• Holding fee • Response energy payment for non-BMU only (£/MW/hr) **EFR**: pay-as-bid-based availability fee (£/MW/h) that is paid for the hours a provider has tendered to make the service available to NGT
Total FCR volume	+/- 64 MW in 2018 permanently available in the APG control area	FCR ~23 MW FCR-N ~ 22 MW FCR-D ~ 37 MW (less than 200 MW = the combined requirement in the ENTSO-E RG Nordic grid)	~600 MW required for France (~3000 MW for the continental synchronous system)	-	-	FCR-N ~230 MW (In the Nordic synchronous > 600 MW, shared on the basis of annual consumption in Eastern Denmark, Finland, Norway and Sweden) FCR-D ~410 MW, volume based on a dimensioning incident = largest fault of production or HVDC deducted by 200 MW for frequency dependent load	**FFR** [45]: • dynamic: 354 MW • static ~0 MW **EFR**: 201 MW **FCDM**: not public

Remarks on FFR, MFR and EFR in Great Britain

The FFR provides:

- a dynamic frequency response, i.e. a continuous service to manage second-by-second changes: the generation output will rise and fall automatically in line with the system frequency,
- a non-dynamic frequency response, used as a discrete service triggered at a defined frequency deviation (marginal), i.e. where an agreed amount of energy is delivered if the system frequency hits a certain trigger point e.g. 49.8Hz

The obligated generators can provide other balancing services, as long as doing so does not interfere with their ability to deliver MFR, or outside of their tendered FFR windows.

For EFR, providers can offer other balancing services outside of their tendered EFR windows but their units must be ready and in frequency sensitive mode at the start of each EFR window.

Both FFR and MFR provide a primary reserve, a secondary reserve and a high frequency reserve.

7.1.5 Automatic Frequency Restoration Reserve (aFRR) [55] [45] [66]

There is no explicit mechanism equivalent to aFRR in Great Britain (ENTSO-E [66] [55] mentions that aFRR is not used in the UK). But as described in the previous FCR section and Table 22, the two FCR mechanisms called MFR (Mandatory Frequency Reserve) and FFR (Firm Frequency Response) are composed of both primary and secondary responses. Table 23 below describes the characteristics of aFRR mechanisms in the case study countries, except Great Britain.

Table 23 - Characteristics of the aFRR mechanisms in the case study countries

	Austria [214]	**Denmark** [198] [199] [67] [215]	**France** [202] [201]	**Italy** [204]	**Spain** [205] [216] [207]	**Sweden** [215] [217] [199]
Names of mechanisms	aFRR (former secondary control)	aFRR supply capability both in DK1 and DK2	aFRR, previously *Réserve Secondaire*	Secondary power reserve via the Market for Dispatching Services	Reserva de regulacion secundaria	aFRR (since 01/2013)
Providers & eligible technologies	Providers must have a valid technical prequalification, valid for three years	Production or consumption units can participate if they have a contract as balancing capacity with the TSO to participate in the balancing market Reserve supplied by a combination of plants in operation and fast-start plants.	Large generation (mandatory participation for generating units > 120 MW) + small injection (generation) and withdrawal (consumption) (voluntary participation) Certification condition to participate (undefinite duration): • generation reserves connected to transmission grid: no need of certification because they are already meet the technical conditions • all the other cases : the "responsable de réserve" (injection or withdrawal) must be certified by RTE	n/a No RES which cannot be scheduled	Generation plants enabled and integrated in regulation zones	Production or consumption units can participate if they have a contract as balancing capacity with the TSO to participate in the balancing market
	Aggregated generation accepted, load participation and aggregated load accepted [45]	Demand Response participation, aggregated demand accepted, aggregated generation accepted	Aggregated generation accepted, Demand Response participation, aggregated load, accepted since 2014 but limited to sites connected to transmission grid.	Not accepted: demand response, aggregated demand response and aggregated generation	Not accepted: demand response and aggregated demand response	Demand Response participation, aggregated demand accepted, aggregated generation accepted

	Austria [214]	**Denmark** [198] [199] [67] [215]	**France** [202] [201]	**Italy** [204]	**Spain** [205] [216] [207]	**Sweden** [215] [217] [199]
			Participation of consumers connected at the distribution level has been theoretically authorized since 2016.			
Thresholds **Min. offer**	> 5 MW Minimum bid increment: 1 MW	> 1 MW (maximum offer: < 50 MW) Minimum bid increment: 1 MW	> 1 MW Minimum bid increment: 1 MW	- (> 5 MW for interruptible contracts in mainland)	- (> 5 or > 90 MW for interruptible contracts in mainland)	> 5 MW
Types of products	Positive, negative. Mon–Fri: peak (8h-20h) Mon-Fri: offpeak (20h-8h), Weekend (48h)	Symmetrical Operators can submit bids to the hourly market separately for upward and downward capacities	Symmetrical			
Ramping (slopes)	Full activation time (FAT) is 5 min. After 30s the start of activation must be visible in the active power measurements. Tolerance: 3% for underperformance 20% for over-performance (not critical but over-performance is not paid)	DK1 Zone: Full activation within 15 min DK2 Zone: Full activation within 5 min	In extreme conditions, full activation • within 400s for half range (-P to 0 or 0 to +P) • within 800s full range (-P to +P) Fixed response for all aFRR for all bids [66] Power volume: • control range of at least +/- 4.5 % of Pmax • half control range which, once cumulated with the primary reserve range, must be > 7 % of Pmax	(Like for tertiary reserve) ability to vary, either increasing or decreasing, the injection within 5 min of the initiation of the requested variation Fixed response for all aFRR for all bids [66] Power volume: • Hydro: ±15% of the maximum power of the infrastructural element. • Thermoelectric units: the greater of ±10 MW and ±6% of the maximum power of the infrastructural element	No more than 30s Fixed response for all aFRR for all bids [66].	Full activation within 120s Flexible response: TSO sends requests for activating aFRR, balancing service provider responds within FAT [66]

	Austria [214]	Denmark [198] [199] [67] [215]	France [202] [201]	Italy [204]	Spain [205] [216] [207]	Sweden [215] [217] [199]
Deployment duration	No limit (except end of bid) No limit between two activations No limit for the number of activations per period	n/a	No duration limit Permanent availability No limit for the number of activations per period	At least 2 hours	15 minutes until the tertiary regulation acts	n/a
Type of participation	Voluntary But in case of insufficient volume after the "last call" (third bid round), APG (Austrian TSO) can oblige suppliers to make available and provide the secondary control power Common activation of aFRR in Germany and Austria (common merit-order list based on a TSO-TSO model)	Voluntary	Mandatory participation for generating units > 120 MW Unpredictable units are exempted Voluntary participation for the other eligible units	Mandatory participation for eligible units: obligation to make the secondary power reserve service completely and exclusively available to the TSO	Voluntary Activation of the RCP (Joint Regulation System) and the AGC (Automatic Generation Control) when there is a frequency variation.	n/a
Type of selection	Biding period for weekly products from Friday 12:00 pm to Wednesday 3:00 pm Bid ranking according to: 1. Lowest power price (merit-order-based) 2. If same power price: lowest energy price for positive secondary control, highest energy price for negative secondary control 3. If identical power and energy prices, the bid placed first wins In future bid, acceptance according to mixed price (= capacity price + energy price)	In the hourly market, Energinet selects the bids such that the total need is met at the lowest possible cost. Bids are always accepted in their entirety or not at all. If two bids are priced the same, and Energinet only needs one, a mechanical random generator is used to select one of them. The requested aFRR is distributed pro-rata to the aFRR providers connected to the LF controller	No organised market as such: RTE is fully in charge of the procurement. Contractualization made in day-ahead: RTE determines the final obligation at 17h00 PM day-ahead. The selection is pro rata based: RTE instructs aFRR providers in parallel and the requested aFRR is distributed on a pro-rata basis to the aFRR providers connected to the LF Controller [66]	17h00 day-ahead: providers submit their tenders. 20h30 day-ahead: TERNA determines the reserve. The selection seems to be pro rata-based: TERNA instructs aFRR providers in parallel and the requested aFRR is distributed on a pro-rata basis to the aFRR providers connected to the LF Controller [66]	Daily call for tenders in day-ahead, based on REE needs. The selection seems to be pro-rata based: the TSO instructs aFRR providers in parallel and the requested aFRR is distributed on a pro-rata basis to the aFRR providers connected to the LF Controller [66]	The selection seems to be pro-rata-based: the TSO instructs aFRR providers in parallel and the requested aFRR is distributed on a pro-rata basis to the aFRR providers connected to the LF Controller [66]

	Austria [214]	Denmark [198] [199] [67] [215]	France [202] [201]	Italy [204]	Spain [205] [216] [207]	Sweden [215] [217] [199]
Remuneration	Pay-as-bid approach. Both a capacity price and energy price are paid Energy price limits between -9999,99 and +9999,99 €/MWh	In addition to the capacity payment, the operator receives a separate energy compensation based on regulation carried out.	Regulated reservation price (€/MW): currently 9,098 €/MW /30 min (revised each year on the 1st of January) Activation price presently based on a reference spot price to deliver 1 MWh for a specific time (€/MWh) Debates are ongoing to implement a pay-as-cleared pricing for activation.	Pay-as-bid remuneration	Pay-as-clear approach both for reservation and energy. This remuneration takes into account the situation of the tertiary reserve: • for upward, if tertiary reserve is emptied, secondary remuneration is multiplied by 1,15; • for downward, if tertiary reserve is emptied, secondary remuneration is multiplied by 0.85	Reservation: pay-as-bid Activation: marginal price on Regulating Power Market; price for up and down regulations
Contracted volume	Total contracted volume: +/- 200 MW procured in weekly and daily tenders Ratio aFRR activated / (aFRR + RR + mFRR): beyond 80 %	Total contracted volume: ~ 100 MW Ratio aFRR activated / (aFRR + RR + mFRR): < 20%	Total contracted volume: ~ 650 MW Ratio aFRR activated / (aFRR + RR + mFRR): between 40-60 %	Total contracted volume: ~ 570 MW Ratio aFRR activated / (aFRR + RR + mFRR): between 20-40 %	Total contracted volume: ~ 600-700 MW Ratio aFRR activated / (aFRR + RR + mFRR): between 20-40 %	Total contracted volume: ~ 150 MW Ratio aFRR activated / (aFRR + RR + mFRR): < 20%

7.1.6 Balancing mechanisms, manual Frequency Restoration Reserve (mFRR) and Replacement Reserve (RR) [82] [55] [45] [83] [80]

Table 24 - Characteristics of the balancing, mFRR and RR mechanisms in the case study countries

	Austria [218]	**Denmark** [198]	**France** [219] [74] [220] [51]	**Italy** [204] [203]	**Spain** [206] [221] [205] [206] [207]	**Sweden**	**Great Britain** [222] [223] [59] [210] [212] [211] [60]
Names of mechanisms	mFRR (former tertiary control) RR is procured via the intraday market	mFRR Balancing Process mFRR Congestion Management Process No RR [55]	Balancing market + contracted reserves to restore the secondary reserve, including: • mFRR: Réserve rapide • RR: Réserve complémentaire • contracts "réservation de puissance" with some large consumers	No tertiary reserves strictly speaking but a system of margins managed by TERNA via the ancillary service market (MDS). Two types of reserves: • the spinning reserve to restore the secondary reserve • the replacement reserve to restore to restore the spinning one + Interruptible contracts (signed for three years).	Reserva de regulación terciaria as contracted reserves + RR = mecanismo de gestión de desvíos (**MGD**) for forecasted Supply/Demand imbalances >300MW + Reserva de potencia a subir (**RPS**) if after the spot gate closure, a lack of power is forecasted for the next day + Interruptible contracts	mFRR power reserve Fast Disturbance reserve Balancing Market (RPM or Regulating Power Market)	**Fast Reserves**: similar to STOR but with a much faster timescale. Two types: • Firm Fast Reserve • Optional Fast Reserve **STOR** (Short-Term Operating Reserve) **BM unit start up** (BM=Balancing mechanism): process of bringing the unit able to synchronise with the system within BM timescales **BM unit Hot standby**: holds the generating unit in this state of readiness **Demand-Turn Up** (DTU), a summer-only service to help manage periods of low demand
Providers and eligible technologies	Generators, load, pump storage units pumping	Generators and peak load reserves	Transmission-connected generators, large generators connected to the distribution grid, foreign players, large consumers, aggregators of large and small consumers As of January 2018, a derogatory regime was introduced for small balancing units under certain conditions.	Generators connected to transmission grid Non-predictable RES are not eligible	Generators and pump storage units pumping	Generators and loads	Generators and pump storage units pumping **Fast Reserve** opened to BM and non-BM providers including Transmission-and Distribution-connected generators, storage providers and aggregated demand side response. **BM units**: generators **STOR**: generation or steady demand reduction (possibly aggregation of more than one site)

	Austria [218]	**Denmark** [198]	**France** [219] [74] [220] [51]	**Italy** [204] [203]	**Spain** [206] [221] [205] [206] [207]	**Sweden**	**Great Britain** [222] [223] [59] [210] [212] [211] [60]
							DTU: large consumers, any type of up/down generation, energy storage (batteries, etc.).
	Aggregation allowed Load access & participation Aggregated load and aggregated generation accepted	Aggregation allowed Load access & participation Aggregated load and aggregated generation accepted	**mFRR & RR**: Load access & Participation; Aggregated load and aggregated generation accepted **Dedicated Demand Side Resonse-RR**: Load access & participation; Aggregated load accepted; no aggregated generation	**Tertiary reserve**: aggregated demand response not accepted; aggregated generation not accepted **Interruptible** (mainland and islands): demand response accepted but no aggregation	Aggregation allowed **RR tertiary control**: Load access & participation; Aggregated load accepted **RR Deviation management**: demand response not accepted **Interruptible**: demand response accepted but no aggregation	Aggregation allowed mFRR: aggregated demand response accepted, aggregated generation accepted	**Fast Reserve**: load access & participation; Aggregated load and aggregated generation accepted **DTU**: possibility to aggregate from sites 0.1 MW and larger **STOR**: possible aggregation of more than one site
Thresholds Min. and max. offer	Capacity: min. offer 1 MW for the first bid and 5 MW for further bids Max. offer: 50 MW	Capacity: 5 MW Energy: 5-10 MW Max. offer: 50 MW	**Balancing market**: offers > 10 MW for upward & downward **mFRR & RR**: > 10 MW Max & min power volumes specified by the "adjustment entity" or "entité d'ajustement" (EDA) in its initial use declaration Derogatory regime for small balancing units: min > 1 MW and max < 10 MW	Ability to increase / decrease injection by at least 10 MW for tertiary reserve and 3 MW for balancing within 15 min in both cases. Interruptible contracts: > 1 MW	**RR**: Capacity: 10 MW Energy: 10 MW **Interruptible** Mainland: 5 MW blocks or 90 MW blocks	mFRR: > 10 MW (> 5 MW for bidding area SE4) Fast disturbance reserve: according to agreement Regulating Power reserve: > 5MW	**Fast reserve**: must be able to deliver minimum of 50 MW (> 25 MW from April 2019) **STOR**: > 3 MW **DTU:** > 1 MW (fractions of MW authorized for offers; ex.: 4.2 MW)
Types of products	Positive, negative are separate products	Bidirectional Two mFRR products: • a European standard product as defined in the joint European market coupling initiative	Bidirectional		Bidirectional	Bidirectional	Bidirectional

	Austria [218]	**Denmark** [198]	**France** [219] [74] [220] [51]	**Italy** [204] [203]	**Spain** [206] [221] [205] [206] [207]	**Sweden**	**Great Britain** [222] [223] [59] [210] [212] [211] [60]
		• a complementary specific product to support congestion management					
Ramping (slopes)	Activation time between 10-13 minutes Underperformance 3%; over-performance no limit and not remunerated	mFRR full activation time: 15 min Complementary specific product: full activation time: 5 min	**mFRR**: activation within 13 min (bonus or “bonification” if activation within 9 min) **RR**: activation within 30 min Tolerance for mFRR & RR: "relative failure" if vol. ordered – vol. realized > 10%) **Balancing market**: activation time (DMO) specified by the use conditions of each EDA. The operating program for each “production entity” or “entité de production” (EDP) is sent by each EDP to RTE in day-ahead Tolerance: failure if missing volume larger than the minimum between 20% of the volume ordered by RTE and 50 MWh	Spinning reserve: increase / decrease injection by at most 50 MW within 15min Replacement reserve: up or down within 120 min	mFRR: within 15 min MGD: up/down energy offers within 30 min after the notification Interruptible contracts: 200 ms	mFRR and Fast disturbance reserve: activation time between 5-15 minutes	**Fast reserve:** • Firm Fast Reserve: delivery within 2 min, with a delivery rate in excess of 25 MW/min Notifications in H-36. • Optional Fast Reserve: idem but notifications in day-ahead **STOR**: response within 240 min (although within 20 min is preferable) **BMU:** • ability to terminate start up process at any time, prior to reaching hot standby • Once in hot standby, ability to respond within 89 min **DTU:** speed to respond depending on the provider (average time between instruction and starting to deliver 7h 20 min in 2016; 6h 40 min in 2017)
Deployment duration	Minimum: 1 min (new rules starting in 2018) Max duration is the contracted duration (i.e. no limit if all time slots have been accepted)	Maximum product duration: hours Distance to real-time: 5 min < x <15 min The Nordic mFRR product is directly activated, which means that the activation is not	mFRR: several possible max. duration or "durée d'utilisation max" (DOmax) within 30, 60, 90 or 120 minutes RR: several maximal duration within 30, 60 or 90 minutes	Spinning reserve when the unit is running Replacement reserve: when the unit has to be turned on Unlimited duration	At least for two hours Distance to real-time: 15 min < x <H-1	mFRR: adjustments no later than 45 min before delivery hour Regulating ower reserve: endurance demand 2 h. Should be available 24/7, from 16 nov – 15 mar	**Fast reserve**: during 15 min (average = 5 min at a time) **STOR**: min of 2 hrs. **DTU:** duration of delivery depending on the provider (average: 4h 20 min in 2016; 3h 34 min in 2017)

	Austria [218]	**Denmark** [198]	**France** [219] [74] [220] [51]	**Italy** [204] [203]	**Spain** [206] [221] [205] [206] [207]	**Sweden**	**Great Britain** [222] [223] [59] [210] [212] [211] [60]
	Distance to real time: > H-1	bound to a specific market time.					
Elements on activations (duration, number per period, etc.)	No limit for duration No limit for the number of activation per period.	n/a	mFRR: duration communicated by each unit [81] mFRR & RR: able to cover two daily occurrences of an incident equivalent to the largest possible generation incident in the French continental perimeter (loss of 1500 MW)	RR duration communicated by each unit Ability to follow the necessary ramping, 4 hours a day, 7 days a week	RR duration communicated by each unit	n/a	**Fast Reserve:** • duration communicated by each unit (on average, providers used 10 times per day) • service required 24 hrs a day, 7 days a week. But greater requirement for service during daytime, typically between 06:00-23:00 (in average, 10-15 activations per day) **STOR**: up to several times per day **DTU**: service running from 1st May to 30th October; no commitment to be available 24/7 or for every availability window: providers declare the MW available (weekly basis or longer period)
Type of participation	Voluntary	Voluntary	**mFRR & RR**: pre-contracted and mandatory offers [82]. Once the bid is retained, the contract imposes that the contractor is able for each day of the time step and for each moment of these days, to submit on the balancing market, the contracted volume of upward power **Balancing market**: mandatory	Mandatory	Capacity: Mandatory Generators connected to the grid are obligated to offer the remaining/available capacity Energy: organized market (voluntary)	Voluntary	Mandatory offers + Pre-contracted offers [55] Optional Fast Reserve agreement with no obligation on either party but allows optional dispatch of Fast Reserve when available. Concerned providers can refuse to participate

	Austria [218]	**Denmark** [198]	**France** [219] [74] [220] [51]	**Italy** [204] [203]	**Spain** [206] [221] [205] [206] [207]	**Sweden**	**Great Britain** [222] [223] [59] [210] [212] [211] [60]
Type of selection	**mFRR**: organized market • Weekly auction, currently based on lowest capacity prices (in the future the mixed price will be the acceptance criteria; mixed price = capacity price + energy price of the bid) • Daily auction: energy price is relevant for bid acceptance Maximum product resolution: weeks	**mFRR**: organized market Daily auctions with an hourly product resolution: an auction is held once a day for each of the hours of the coming day of operation Availability of mFRR resources achieved by 5-years contracts in the DK2 zone and daily capacity markets in the DK1 zone	**mFRR**: organized market with a daily product resolution and a yearly distance to real time of reserve auctions [55] **RR**: organized market, with a yearly distance to real time of reserve auctions **Balancing market**: • selection of bids via an economic precedence in respect of technical issues (grid and installation), at least one hour before the beginning of the activation • economic precedence can be restricted temporarily, totally or partly by RTE (to solve congestions or to restore margins and ancillary services)	**Tertiary reserve**: the SO provides for the availability of resources for the tertiary power reserve concurrently with the process of defining the binding programs or with the procedure for the selection of balancing resources, via the ancillary services market (MDS) **Balancing**: the SO provides for the availability of resources for balancing via the MDS	Daily process in day-ahead (merit order via daily tenders), for mFRR, MGD and RPS RPS: tendering process after the spot gate closure, if a lack of power is forecasted for the next day. The winning bids shall be available to propose their capacity during the relevant intraday windows.	**mFRR**: Organized market Price bid on energy needs to be handed in 14 hours before delivery hour (of energy), adjustments no later than 45 min before delivery hour Maximum product resolution: months	**Firm Fast reserve:** monthly tenders (bids for a single month, multiple months (2-23) or long term (1-10 yrs). **STOR**: 3 tenders / year, six "seasons" / year, each tender round covering particular seasons, with its own technical and price details. Two ways: • committed service: open to BM and non-BM participants • flexible service: open to non-BM providers with a commitment to deliver STOR **BMU:** bilateral agreement between NGT and the service provider. 1-year contract but possibility to submit price changes to a maximum of once a week. Final merit order via a price comparison at both day-ahead timescales and closer to real time **DTU**: • fixed demand turn up: a single tender in 02/18 for service start on 1st May 2018 • optional demand turn up, with the possibility to change availability and utilisation payments frequently
Remuneration	Capacity: pay-as-bid remuneration for weekly products Energy: merit order via pay-as-bid for weekly and daily products (daily	Capacity: marginal pricing Energy: merit order, marginal pricing	**Balancing market**: pay-as-bid (€/MWh) **mFRR & RR**: • remuneration for reservation (pay-as-clear) €/MW/period	Capacity reservation not remunerated Energy remunerated (pay-as-bid)	mFRR: • Reservation not remunerated • Energy remunerated (pay-as-clear via a merit order)	Capacity: pay-as-bid Energy: merit order, marginal pricing Disturbance reserve: • compensation for power: according to procurement,	Capacity: pay-as-bid Energy: merit order, pay-as-bid **Firm Fast reserve**: availability fee (£/hour) + nomination/positional fee (£/hour) + utilisation fee

	Austria [218]	**Denmark** [198]	**France** [219] [74] [220] [51]	**Italy** [204] [203]	**Spain** [206] [221] [205] [206] [207]	**Sweden**	**Great Britain** [222] [223] [59] [210] [212] [211] [60]
	products receive only energy price) energy price limits are -9999,99 to +9999,99 EUR/MWh		• remuneration for energy (pay-as-bid) €/MWh		Mecanismo de Gestión de Desvíos: pay-as-clear	contract spans over several years • compensation for energy: price for energy is decided in the procurement	(£/MWh) in a given nomination window **Optional Fast Reserve:** Enhanced Rate Availability Fee (£/h) payment, defined by the provider in the agreement, for periods of provision with enhanced MW run-up and run-down rates **STOR**: • Availability payment • Utilisation payment Flexible service: possibility to offer optional utilisation prices. But no optional price for availability payments. **BMU**: pay-as-bid, with possibility to update submitted prices once a week. Two payments: • start up payment (£/h) • hot standby payment (£/h) **DTU:** pay-as-bid • availability payment to fixed DTU providers • utilisation payment to fixed and optional DTU providers
Market size	Volume range: + 280 MW, - 170 MW	-	mFRR: 1000 MW RR: 500 MW Derogatory regime: < 100 MW	RR: ~ 3700 MW Interruptible contracts: market size for fast response = ~3300 MW Mainland, 145 MW Sicily, 135 MW Sardinia	-	-	**Fast Reserve**: 60 MW **RR STOR**: 2494 MW committed & 898 MW flexible

7.2 Gas

This appendix provides additional and/or more detailed information on the gas sector, and more specifically on the natural gas demand, production and imports, the main actors, the gas network, storage and quality, as well as some country specificities.

7.2.1 Consumption, production and imports

The demand for natural gas in Europe is expected to increase from 517.9 bcm in 2015 to 629 bcm by 2030 [224]. Natural gas production within Europe is declining [225] which leads to the need for increasing import. In 2017 the total natural gas imports to EU were 408.7 bcm [226]. The main import countries in 2017 were Russia (40.32%), Norway (27.28%) and Algeria (7.91%). On the other hand, liquefied natural gas (LNG) accounts to 11.61%. By 2035, this would lead to an import of over 70% of Europe's natural gas demand. Gas dependency of the different countries strongly depends on the share of gas production.

The following figures and table give some specific information for the 7 case study countries, namely:

- The natural gas consumption in 2016 and 2017 (Figure 11)
- The main production countries and countries that mainly rely on imports (Table 25)
- The evolution of the natural gas imports and exports between 2008 and 2016 (Figure 12 and Figure 13).

It can be seen that the countries that most imported natural gas are France, Italy, Spain and the United Kingdom.

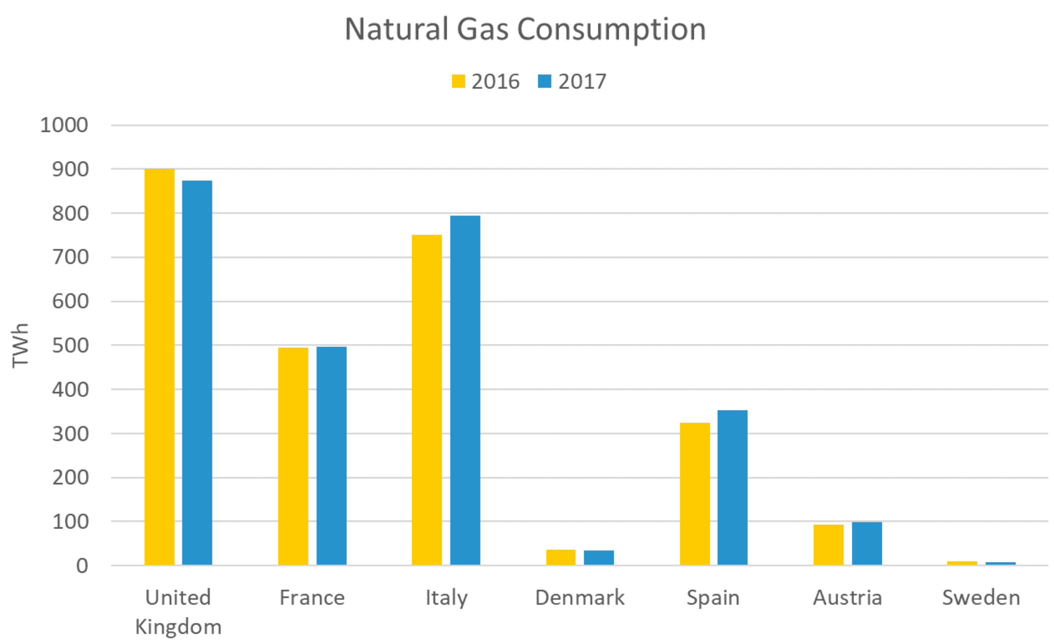

Figure 11 - Consumption of natural gas [227]

Table 25 - Production share in consumption [228]

Production share in consumption[44]		
>80%	Denmark [229]	Countries considered as producers
45-80%	United Kingdom	
2-15%	Italy, Austria	Countries that rely heavily on imports
<2%	Spain, France	
n.a.	Sweden	

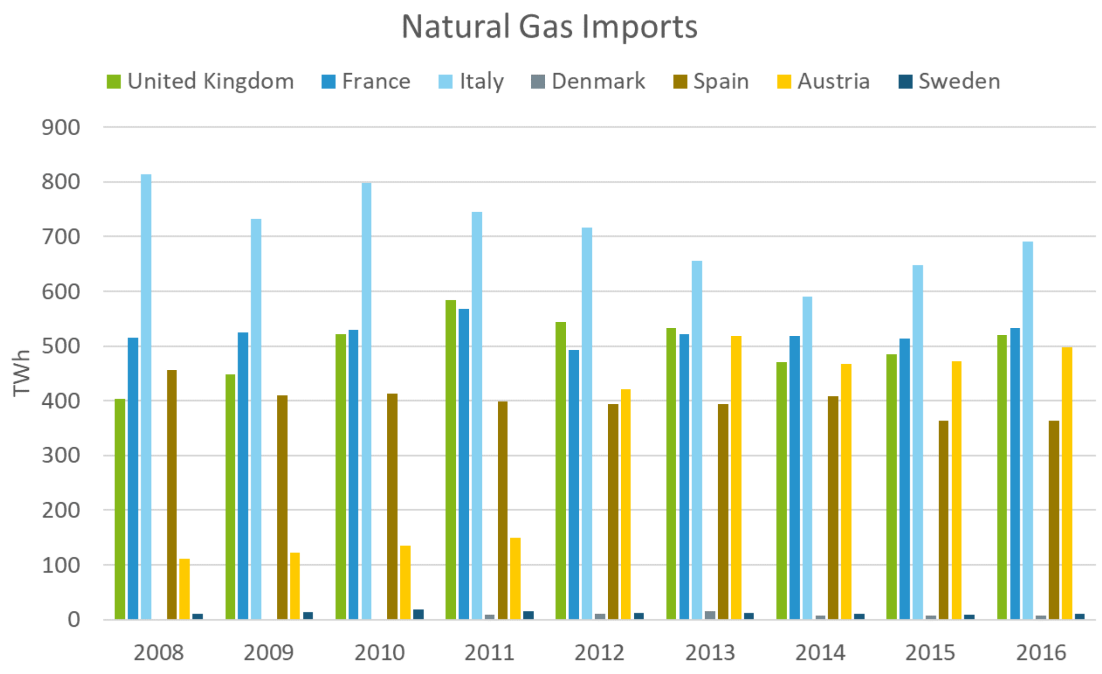

Figure 12 - Imports of natural gas [230]

[44] Calculated as total national production of 2016 / sum of gross inland consumption and exports [228]

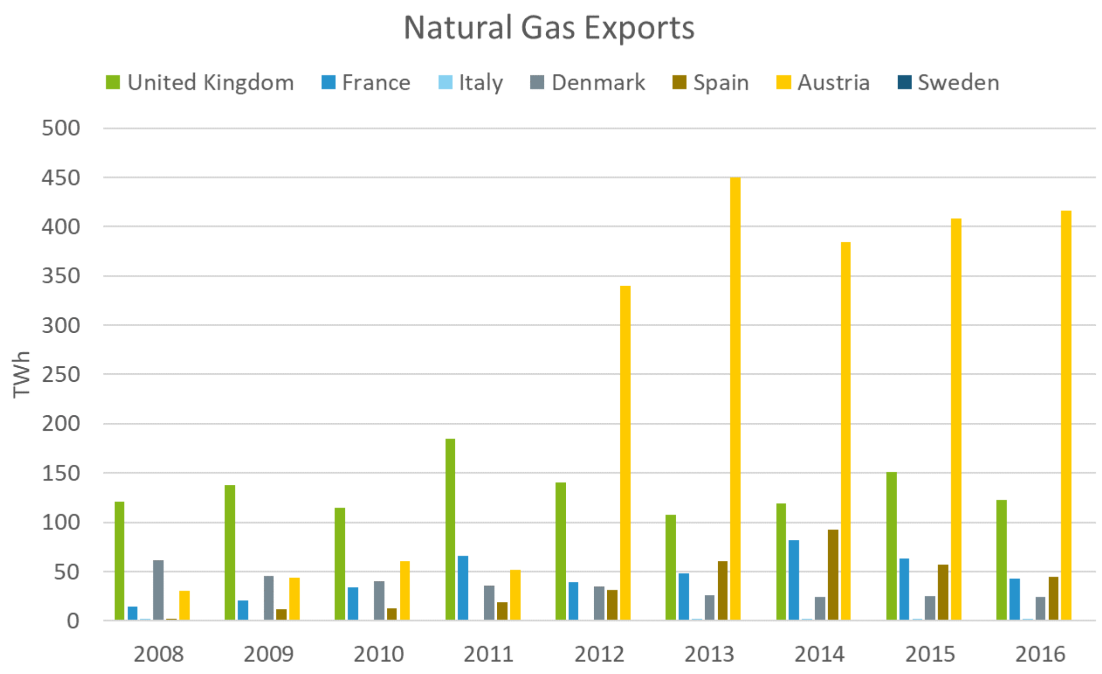

Figure 13 - Exports of natural gas [230]

7.2.2 Main actors

Table 26 - Main actors

Role	Austria	Denmark	France	Italy	Spain	Sweden	UK
Producers	Local production OMV, RAG Russia via Slovakia	North Sea (close down temporarily in the period 2019-2022) Germany Denmark (Biogas producer in Bevtoft Jutland)	Norway, Russia, Netherlands, Algeria, Qatar	Algeria, Russia	Algeria (main exporter)	Danish North Sea gas, and Germany (Russian, Norwegian or Dutch natural gas)[45]	UKCS– *Shell, Gassco,* Europe
Suppliers	Gas connect	HMN Naturgas A/S, OK a.m.b.a, SEF A/S, DCC Energi	Engie, EDF, Total, ENI...		ENAGAS	Axpo Sverige AB, E.ON Försäljning Sverige AB, DONG Energy AB, Göteborg	British Gas EDF Energy E.ON UK RWE Npower

[45] In Sweden there is no source of natural gas and thus no plant for natural gas production. [233]

Role	Austria	Denmark	France	Italy	Spain	Sweden	UK
						Energi AB, Varberg Energimarknad AB and Öresundskraft Marknad AB etc. [231]	Scottish Power SSE
Transmission Operators	Gas connect	Energinet	GRT Gaz, Terega	SNAM Rete Gas, Societa Gasdotti Italia	ENAGAS	Swedegas	National Grid Gas
Technical System Manager	AGGM (market area manager)	Ørsted A/S, NGF Nature Energy A/S			ENAGAS	Swedegas	National Grid Gas
Distributors		Aalborg municipality: Gasforsyningen Southern Sjælland and Southern Jylland: Dansk Gas Distribution Fyn NGF Nature Energy Distribution Northern Jylland and Nothern Sjælland: HMN Gas-Net I/S	GrdF+ 23 local DSOs	SNAM, Hera, A2A, Iren	GAS NATURAL FENOSA	E.ON Gas Sverige AB, Göteborgs Energi Gasnät AB, Kraftringen nät AB, Varberg Energi AB and Öresundskraft AB [232]	Cadent Gas, Northern Gas Networks ltd., Scotland Gas Network Ltd., Southern Gas Network Ltd., Wales & West Utilities Ltd.
Retailers	Ca. 30	HMN Naturgas A/S, OK a.m.b.a, SEF A/S, DCC Energi	Engie, EDF, Direct Energy, Total; ENI…	ca. 400	GAS NATURAL FENOSA	ApportGas, E.ON Försäljning Sverige AB, Göteborg Energi, Kraftringen Energi AB (Publ), Varberg	British Gas, EDF Energy, E.ON UK, RWE Npower, Scottish Power, SSE

Role	Austria	Denmark	France	Italy	Spain	Sweden	UK
						Energi, Öresundskraft, Stockholm Gas [233]	
Independent Commission for market oversight	E-Control	Danish Energy Regulation Authority (DERA)	CRE	ARERA	CNMC	Ei, The Swedish Gas Association [231], The Swedish Consumer Energy Markets Bureau[46], Swedish Competition Authority [231], The Swedish Energy Agency [234]	Office for gas and electricity market - Ofgem
Storage Operator	OMV, RAG						

7.2.3 Networks

The delivery of natural gas from its source to the final consumer happens through a network of pipelines. The basic principle is that gas flows from a higher pressure to a lower pressure. Firstly, there is the transmission network at high pressure for transport over long distances and secondly, there are distribution networks at a lower pressure for transport over shorter distances.

The transmission network is operated by the Transmission Operators which is usually only one company per country. The respective pressure depends on local regulations and operational parameters as well as geographical conditions. The same applies to the distribution network at lower pressure. It is operated by Distribution Operators. There may be multiple Distribution Operators in a country operating different regionally separated distribution networks.

Additionally, in most countries a Technical System Manager (TSM) is responsible for the technical management of the basic and secondary transmission networks as well as the security of supply.

Table 27 summarises the transmission and distribution networks in terms of length and pressure for each of the case study countries.

[46] The Swedish Consumer Energy Markets Bureau is an independent bureau which provides information, advice and guidance in matters concerning the electricity and gas markets. The advisory service is free of charge [233]

Table 27 - Gas transmission and distribution networks

Country	Network	Length	Pressure
Austria	Transmission	2,000 km	70 bar
	Distribution	44,000 km	15-40 bar[47]
Denmark	Transmission	900 km	80 bar
	Distribution	17,000 km	19, 40 or 50 bar[48]
France	Transmission	32,000 km	40-67 bar
	Distribution	197,000 km	0.05-25 bar
Italy	Transmission	34,000 km	100 bar
	Distribution	248,000 km	0.04-24 bar / >24 bar[49]
Spain	Transmission	13,769 km	16-60 bar / >60 bar
	Distribution	71,340 km	<16 bar
Sweden	Transmission	600 km	80 bar[50]
	Distribution	3,540 km	<4 bar [235]
GB	Transmission	7,600 km	34-94 bar
	Distribution	277,000 km	0.75– 40 bar

7.2.4 Storage

Consumption of natural gas fluctuates a lot depending on the season and the day. Gas storages support the gas system in providing the needed flexibility. Table 28 presents the main types of gas storage facilities used at transmission and distribution levels. The respective functions are described in Table 29. Usually, the increments of demand for a season are satisfied with base load facilities which are capable of holding enough gas to satisfy the demand. In these cases, the storage facilities recover their gas level during those seasons when the demand is lower.

To satisfy the peaks of gas demand there are facilities designed to provide the needed gas quickly although they cannot satisfy high levels of demand. Additionally, pipelines can be considered as a storage system in the sense that they provide some flexibility by pressure balance.

[47] Depending on the region.
[48] The distribution system transfers gas at a pressure of up to 7 bar to the individual customer sites.
[49] Depending on consumer and demand volume
[50] Swedegas has set the minimum operating pressure at 45 bar.

Table 28 - Main types of natural gas storage (adapted from [236], [237])

Storage		Function	System Support
Underground	Salt Caverns	Multi cycle	Transmission level
	Depleted field	Limited multi cycle/ seasonal/ strategic storage	
	Depleted aquifer	Seasonal storage/ strategic storage	
LNG (liquefied natural gas) in refrigerated tanks		Peak shaving storage/ System Support Storage	
High Pressure Bullets Tanks		System Support	Distribution level

Table 29 - Main storage functions [236], [237]

Storage Function	Description
Multi cycle /flexible	Gas is injected and withdrawn several times a year. Turnover rates can range significantly.
Seasonal	Gas is mainly injected in summer and withdrawn in the winter.
Strategic	Gas is stored and to be used only at an emergency which are clearly defined.
Peak Shaving	Withdrawal rates are high so that they can meet sudden high demands for a short time.
System Support	These are located close to load centres to back up short term variations in the system.

Figure 14 illustrates the key processes which take place in the mentioned gas storage sites and Table 30 gives a summary for the studied countries of the underground storage capacity and the respective company that acts as storage operator.

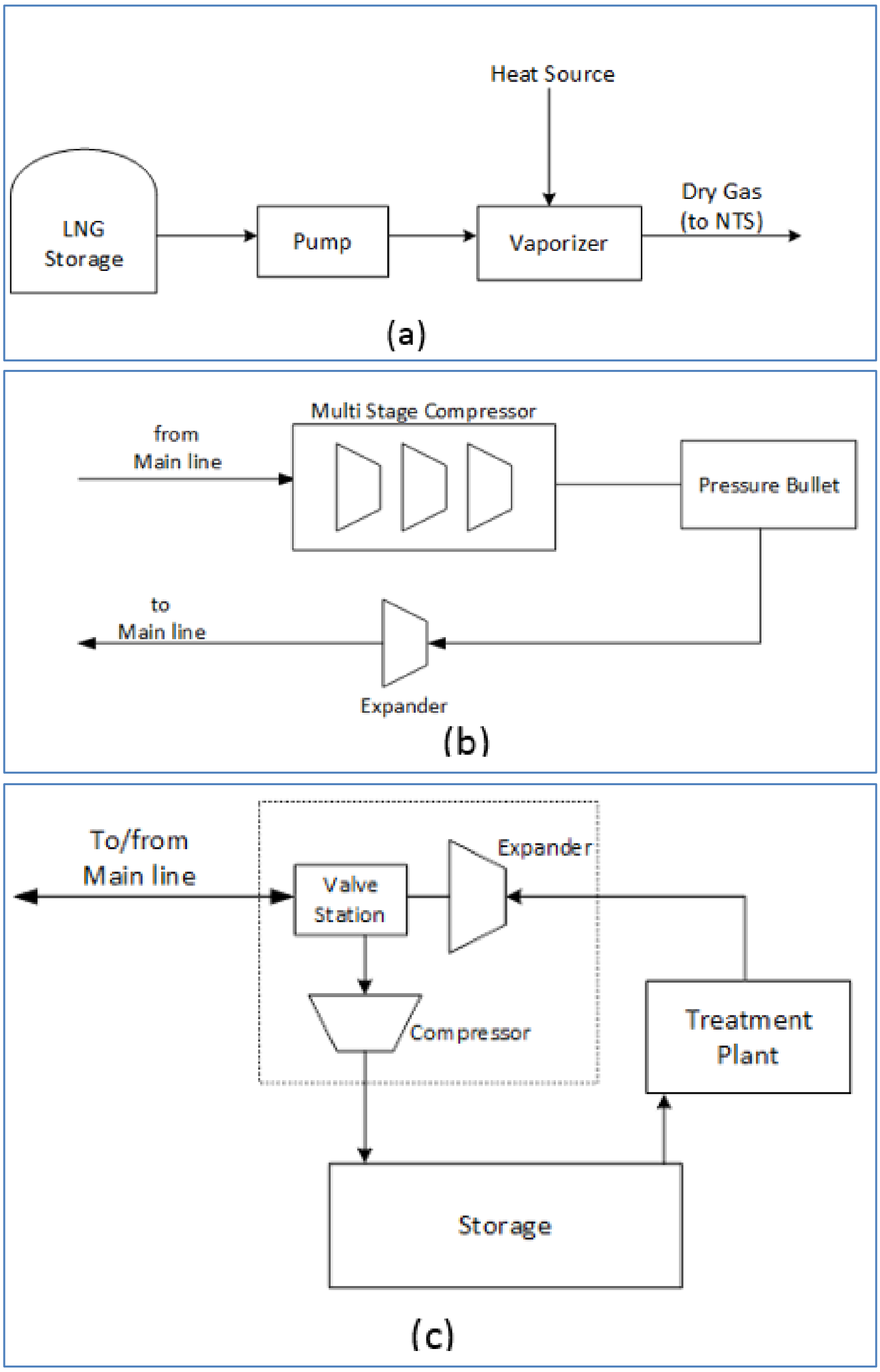

Figure 14 - Schematic of the processes in the gas storage sites (a) LNG storage, (b) Pressure Bullets, (c) Underground Storage (source: Cardiff University)

Table 30 - Summary of underground gas storage per case study country

Country	Operator	Storage Capacity
Austria	OMV and RAG	$8.4x10^9$ m³
Denmark	Gas Storage Denmark A/S (Energinet)	$8.9x10^8$ m³
France	Storengy, Terega, Geomethane	$12.6x10^9$ m³
Italy [238]	Stogit (SNAM group), Edison Stoccaggio	$16x10^9$ m³
Spain	Enagás	$5.8x10^9$ m³
Sweden	Swedegas	$10x10^6$ m³
UK	National Grid	$4.74x10^9$ m³

7.2.4.1 Austria

In Austria the total volume of natural gas storage is higher than the annual consumption. Due to geological conditions, all natural gas storages are porous storages and can be used for seasonal fluctuations. Table 31 presents the storage capacities of the two main storage operators OMV and RAG. The total volume of the Austrian gas storages equals 92,125 GWh (2014). Storage input begins usually in April and lasts until September. In October usually the outside air temperature decreases significantly which leads to the start of the output stage from gas storages.

Table 31 - Storage capacities with size (source: RAG & Bundestministerium für Wirtschaft)

Storages	Mio m³
OMV AG	**2,700**
• Schönkirchen-Reyersdorf	1,680
• Tallesbrunn	400
• Thann bei Steyr	250
RAG	**5,700**
• Haidach	2,600
• 7fields	1,730
• Puchkirchen/Haag	1,080
• Nussdorf/Zagling	117
• Aigelsbrunn	100

7.2.4.2 Denmark

Regarding **storage facilities**, there are two storage facilities in Denmark. Energinet is the owner of Gas Storage Denmark A/S, which operates the gas storage facilities at Stenlille on Sealand and at Lille Torup in Northern Jutland.

Danish storage is used mostly by shippers in order to maintain contractual balance at the end-of-day and it can be used by any natural or legal person with access to the storage facilities who is registered as a storage customer in the register of players.

Total withdrawal of gas from the storage facilities is estimated at 16.2 million Nm3/day, with 8.2 million Nm3/day coming from Stenlille and 8.0 million Nm3/day from Lille Torup. The distribution of withdrawals is optimised to achieve the highest possible grid pressure.

The total storage capacity is approx. 890 million Nm^3, corresponding to about one third of the annual Danish gas consumption.

7.2.4.3 France

In France, there are two types of storage facilities:

- Underground storage facilities (14 sites), owned and operated by Storengy and Terega. These facilities are aquifers or salt cavities (some depleted fields projects are existing but they are not operational). They account for a storage capacity of $12.6x10^9$ m^3;
- LNG Terminals (3 sites) account for a capacity of around $23x10^9$ m^3/year.

7.2.4.4 Italy

The storage system is composed of depleted reservoirs, mostly located in the North. During the gas year[51] 2011-2012, they accounted for $15.6x10^9$ m^3 of working gas capacity, representing 20% of 2011 annual gas consumption (which is higher than the European average at about 14%). According to Gas Storage Europe, Italy has not used 50% of its storage volumes in 2010, 2011 and 2012. However, only $10.5x10^9$ m^3 were available for commercial activities as $5.1x10^9$ m^3 were reserved for strategic storage, whose utilisation is at the sole discretion of the Energy Minister. Withdrawal rates were not very high compared to markets such as Germany. Storage operators offer four basic types of services: modulation storage, storage for TSO balancing purposes, storage for production purposes and strategic storage.

7.2.4.5 Spain

In Spain, Enagás manages the three main operating storage facilities that play a strategic role in the Spanish Gas System: Yela in Guadalajara (2000 million Nm^3), Gaviota in Bizkaia (2700 million Nm^3) and Serrablo in Huesca (1100 million Nm^3). The Underground storage provides flexibility to the Gas system for injection and extraction of gas.

[51] Gas year begins on October 1st.

7.2.4.6 Sweden

The owner of a facility or pipeline for storage of natural gas, or of a gasification facility connected to the Swedish natural gas system must accept, on reasonable terms, natural gas owned by another party for storage or gasification. When requested to accept the input of gas, an owner of a storage or gasification facility must, within a reasonable time, provide written information about the fee and other terms and conditions for the input. This responsibility does not apply if the facility lacks the necessary capacity.

Swedegas owns the Swedish high-pressure transmission pipelines as well as the only natural gas storage facility [231] in the southwest part of Sweden. The storage facility has a capacity of 10 million normal cubic metres (Nm^3) of gas and can handle pressure in excess of 200 bar [239]. It is characterised by high input and withdrawal capacity. These features increase the attractiveness of the facility as a means of optimising the purchase of gas and as assurance against disruptions in supply [239].

7.2.4.7 Great Britain

Gas holders were used to store gas before 1990s in the local distribution level. Later on with the addition of effective pipeline systems and other components the networks were able to function at full capacity without the use of gas holders [240]. Nowadays almost all the gas holders are decommissioned.

The operation of the storage is described with characteristics such as working gas capacity, injection and withdrawal rates (main storage characteristics). The right mixture of aforementioned storages, sources of flexible supply and their optimized utilization helps a secured gas supply [241].

Table 32 - Storage sites in the United Kingdom [242]

Owner	Site	Storage Capacity (Billion m^3)
Centrica Storage Ltd	Rough (closing down)	3.30
Scottish and Southern Energy & Statoil	Aldbrough	0.30
E. ON	Holford	0.20
Scottish and Southern Energy	Hornsea	0.30
EDF Trading	Holehouse Farm	0.02
Humbly Grove Energy	Humbly Grove	0.30
Scottish Power	Hatfield Moor	0.07
EDF Energy	Hill Top Farm	0.05
Storenergy	Stublach	0.20

7.2.5 Gas Quality

In order to ensure the quality of the gas provided, it has to meet certain regulated levels and specifications. Each country has its own quality restrictions. This section outlines some of the regulations and requirements for the corresponding countries.

Austria - The quality restrictions of natural gas in the Austrian gas system are defined in the Gaswirtschaftsgesetz (GWG) and ÖVGW – Richtlinie G31. Quality requirements for gas feed-in and gas transport are defined. A chemical analysis is done at the transfer points.

Denmark - Energinet is responsible at all times for ensuring that the quality of the gas supplied from the gas transmission system complies with the Rules for Gas Transport and the Gas Regulation.

France - In France, there are two Gas Quality standards. The first is H Gas (High Quality) with high net calorific value, around 11.5 kWh/m^3. Gas imported from all countries except the Netherlands reaches this standard. The second one is B Gas (Low Quality) with a low net calorific value, around 10 kWh/m^3. This kind of gas is imported from the Netherlands and is only distributed in northern France. However, imported Gas from the Netherlands is bound to progressively decline to zero in 2029, as gas fields in the Netherlands have been depleting significantly.

Spain - In accordance with the System´s Technical Management Standards[52], the capacities are expressed under specific benchmark conditions so that gas introduced in the Gas System input points must comply with that natural gas quality specification.

Sweden - So far, almost all natural gas in the Swedish system has its origins in the Danish gas fields in the North Sea. Thus, the gas quality has been maintained at an even level. The calorific value, has been very stable. With more biogas and gas from other parts of Europe, the calorific value of gas in the system may vary. To handle this, the industry has agreed on common rules for determining the calorific value. This is now done by a calculation system – Quality Tracker – implemented for the grid in December 2016. The method is reviewed and evaluated on an ongoing basis. With the help of Quality Tracker, the gas can be followed in the grid and the calorific value can be measured at each individual outlet point.

United Kingdom - Natural gas received at onshore gas terminals are treated to ensure a condition that is acceptable to be injected and transported within the transmission system. The process takes place in a processing plant in the reception terminal.

7.2.6 Specific information for Austria and Italy

7.2.6.1 Austria

The Austrian Gas System is divided into three geographically divided market areas: Market Area East, Market Area Tyrol and Market Area Vorarlberg. The Market Area East is the most complex of the three with both transmission and distribution systems. It also works as an essential connection point between Eastern and Southern Europe. The Market Areas Tyrol and Vorarlberg are not connected with the Market Area East and do not have a transmission system. They are connected to the Market Area NetConnect Germany (NCG). Market Area East is connected to Slovakia, Italy, Germany, Slovenia and Hungary. Therefore, the Austrian gas system is an important connector to transport natural gas imports mainly to Southern and

[52] modification of PD-01 draft of 2011-09-11

Western Europe. Figure 15 shows the geographical overview of the three market areas on the left and the transmission pipelines on the right.

Figure 15 - Austrian Gas Market Areas - Map (source: e-control [left side], Gas connect Austria [right side])

7.2.6.2 Italy

The distribution network in Italy is highly fragmented. The distribution service is performed on the basis of more than 6,400 concessions in about 7,100 municipalities. There were about 230 active distribution operators, distributing gas to approximately 23 million customers in 2014. Distribution companies are mainly owned by public entities. The company's share capital (limited to first-level direct participation) sees about 37% of the shares owned by public bodies and 22% by companies. Most (62%) of the total gas supplied is delivered in northern Italy. This is due to the diversity of climate and to a larger presence of industries in those areas.

Market fragmentation has diminished significantly over the years. However, the number of very small companies in the local gas distribution market is still high.

The Italian gas market is among the largest in Europe. It faced a reduction in demand between 2010 and 2014 (in line with EU trend) especially in the power generation sector, with the financial crisis and environmental policies being the drivers of this contraction.

Italy is highly dependent on gas imports, having nowadays Russia as first supplier (47%), followed by Algeria (12.3%) and Libya (11.7 %). Domestic production covers a small part of gas demand (a quota equal to 11.5% in 2014, 33% from onshore fields and 67% from offshore exploitation).

Over the last years the gas market has been subjected to - and is still being faced with - important changes in terms of structure and regulatory framework. New law provisions, which aim at increasing competitiveness and ensuring the transfer of economic benefits to final consumers, also apply to the local distribution networks.

The Italian gas industry is fully liberalised. However, the wholesale market is dominated by a few players so it has yet to reach its full potential.

Gas enters the Italian national network at seven entry points, five of which are pipelines (Mazara, Gela, Tarvisio, Passo Gries and Gorizia) and two are LNG terminals. Two pipeline entry points (Tarvisio and Mazara) account for almost two-thirds of Italy’s gas imports. Italy’s largest entry point is the TAG pipeline interconnection through Tarvisio in the north-east of the country (maximum capacity of 4.99 MMcm/h) that brings gas from Russia. The Trans-Tunisian Pipeline Company (TTPC) and Trans-Mediterranean Pipeline Company (TMPC) interconnection from Algeria through Tunisia and across the Mediterranean to Mazara del Vallo in Sicily is also significant (maximum capacity of 4.40 MMcm/h).