REPORT

Long-duration energy storage

Regulatory environment and business models in Germany, Spain, France, Italy, and Great Britain

Report created for SPRIND GmbH

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List of abbreviations

	Abbreviation for …
AC	Alternating current voltage
ACER	EU Agency for the Cooperation of Energy Regulators
aFRR	Automatic Frequency Restoration Reserve
BEIS	UK Government Department for Business, Energy & Industrial Strategy
BM	Balancing mechanism
bn	Billion
BNetzA	Bundesnetzagentur
CAES	Compressed air energy storage
C&I	Commercial and industrial (companies)
CM	Capacity market
CNMC	Spanish National Commission of Markets and Competition
ct	Cent
DC *(1)*	Direct current voltage *(abbreviation 1 or 2 can be clearly deduced from context)*
DC *(2)*	Dynamic Containment *(abbreviation 1 or 2 can be clearly deduced from context)*
DM	Dynamic Moderation
DNUoS	Distribution System Use of System Charge
DR	Dynamic Regulation
DSO	Distribution system operator
DSR	Demand-side response
EASE	European Association for Storage of Energy
EBGL	EU Guideline on Electricity Balancing
EC	European Commission
EMD	EU Electricity Market Directive
EMR	EU Electricity Market Regulation
EOM	Energy-Only Market
EP	European Parliament
EPEX	European Power Exchange (electric power exchange; operates in Austria, Belgium, Denmark, Finland, France, Germany, Great Britain, Luxembourg, the Netherlands, Norway, Poland, Sweden, and Switzerland)

EU	European Union
EV	Electric vehicle
FAT	Full activation time
FCR	Frequency containment reserve
FFR	Firm Frequency Response
GB	Great Britain
GDUoS	Generation Distribution Use of System
GW	Gigawatt
GWh	Gigawatt-hour
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LAES	Liquid air energy storage
LCOE	Levelized costs of electricity
LDES	Long-duration energy storage
LLES	Long-duration large-scale storage
mFRR	Manual Frequency Restoration Reserve
MGP	Italian day-ahead market for wholesale electricity
MIBEL	Mercado Ibérico de Electricidade
mn	Million
MPEG	Italian daily products electricity market
MSD	Mercato Servizi di Dispacciamento (Italian balancing market)
MW	Megawatt
MWh	Megawatt-hour
MWh	Megawatt hour
N/A	Not applicable
NECP	National Energy and Climate Plan
NIMBY	Not in my backyard
NRA	National regulatory authority
OTC	Over the counter
PHS	Pumped hydro storage

PICASSO	Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation
PPA	Power purchase agreements
PUN	In Italy: single national purchase price across all zones (*Prezzo Unico Nazionale*)
RED	EU Renewable Energy Directive
RES	Renewable energy sources
RR	Replacement Reserves
RTE	Réseau de Transport d'Électricité
SATA	Storage-as-transmission assets
SEG	Smart export guarantee
TNUoS	Transmission Network Use of System Charge
ToU	Time of use (tariffs)
TRM	Technical Restrictions Market
TSO	Transmission system operator
UK	United Kingdom
VPP	Virtual power plant

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1. Executive summary

Due to the increasing importance of intermittent renewable energy generators (such as wind and solar PV), balancing the supply and demand of electricity is a growing challenge. Together with other flexibility options, energy storage is a central building block to address this challenge by storing excess energy when it is available and releasing it when it is needed. While short-duration energy storage systems such as lithium-ion batteries are already well established, interest is growing for long-duration energy storage (LDES) technologies that can store energy from multiple hours to weeks or even months and are therefore able to balance supply variations caused by prolonged weather events and seasonal fluctuations.

Against this background, Aurora Energy Research (Aurora) was commissioned by SPRIND (*Bundesagentur für Sprunginnovationen*) to analyse the regulatory environment for LDES, assess potential business cases, and identify policy and regulatory measures that are suitable to support these business models. The geographic focus is on Germany, France, Spain, Italy, and Great Britain. In consultation with SPRIND, LDES is defined as technologies providing a storage duration of at least ten hours (i.e., continuous withdrawal of energy from the storage system for at least ten hours).

The aim of the study is to provide start-ups working on promising long-term energy storage technologies with a better understanding of electricity markets, as well as to provide guidance in developing business models and making market entry decisions.

The key findings of the study are summarised below.

1.1 Policy and regulatory framework

The liberalisation of electricity sectors across Europe has led to an increasing harmonisation of power markets and generally improved the market access conditions for operators of energy storage assets. In recent years, EU legislation has also strengthened the role of energy storage and addressed some of the major regulatory barriers to its deployment (such as lack of definition, double charges, and unclear ownership rules for grid operators).

Despite this progress, there are still considerable differences both in terms of the design of power markets in general and specific policies and regulations related to energy storage and its applications. With regards to the design of power markets and the mechanisms used for the procurement of ancillary services, the level of harmonisation and access to energy storage varies considerably between the type of market or service:

- Day-ahead and intraday markets are the most harmonised and open for energy storage in all five countries.
- Capacity markets do not exist in all countries and key design elements (such as the choice of a centralised vs. decentralised procurement, contract durations, auction frequency, etc.) differ between the countries with a capacity market in place. Where capacity markets are available (France, Italy, Great Britain), energy storage is eligible for participation.
- Concerning balancing and frequency ancillary services, several pan-EU harmonisation projects have been launched but the implementation is still pending in many countries. Therefore, the picture is still quite heterogeneous in terms of the types of services available and their access requirements. Tenders are already the most widespread procurement mechanism, but energy storage is not yet fully eligible for participation in all countries.
- The procurement of other, non-frequency ancillary services is least harmonised. In most of the five countries, there are no markets for these services and transmission system operators (TSOs) use bilateral contracts for their procurement or make the provision mandatory for certain generators. For these reasons, the revenue potential for energy storage assets is

currently limited in most countries. Great Britain is most advanced with regards to market-based procurement of non-frequency ancillary services.

Concerning the specific policies and regulations relating to energy storage and LDES there are clear differences between the countries as well. While the barriers mentioned above have been addressed in most national legislations, double grid charges (for the withdrawal and the injection of electricity) are still in place for transmission-grid connected storage facilities in France, for instance. Other countries (Germany and Italy) offer generous exemptions from grid fees and taxes for energy storage facilities. There are also differences in terms of whether the respective governments have defined national strategies for energy storage and whether there are financial support programmes for energy storage in general or even for LDES specifically (more on this below).

1.2 LDES business models

Applying the logic of clustering energy storage applications according to the users of the energy storage asset, four potential business models for LDES are identified in this study:

1. **Stand-alone grid scale storage**: LDES is used as a stand-alone asset to perform market arbitrage and provide ancillary services. The main users are traders, utilities, and major energy companies.
2. **Co-location with renewables plants**: LDES is applied in conjunction with renewable assets such as wind parks or solar PV installations to optimise generation and save costs. The main users are renewable power producers.
3. **Customer energy management**: LDES is installed behind-the-meter at a C&I energy consumer to reduce electricity costs, increase self-consumption, save emissions, or generate revenues from market participation.
4. **Storage-as-transmission asset (SATA)**: LDES is used by grid operators as an integral part of the transmission infrastructure to increase the efficiency of the grid usage, avoid congestion, and save on grid expansion costs.

Based on an analysis of the respective market potentials, including a consideration of the advantages and disadvantages compared to short-duration lithium-ion batteries and an assessment of the project landscape, the business models *stand-alone grid scale storage* and *co-location with renewables plants* currently have the highest overall potential for LDES. Even with these business models, however, market interest differs considerably within the geographical focus area of this study. While stand-alone LDES projects have already been announced or are under development Italy, Spain, and Great Britain, there are little signs of interest for this business model in France. With regards to LDES for co-location with renewables, feasibility studies have been launched by market players in Italy and Great Britain.

The use of LDES for *C&I customer energy management* is less developed but could be interesting for certain companies for which the specific properties of LDES offer a significant advantage over conventional lithium-ion batteries. Examples include companies that have a load profile characterised by prolonged peak loads and such that aim to maximise self-consumption (e.g., in combination with a solar PV system). LDES are also already used in some data centres for back-up storage, albeit not in Europe. According to Aurora's country experts, there is at least some upcoming interest for the use of LDES for the energy management of C&I consumers in Spain and the UK.

Using energy storage assets as integral part of transmission infrastructure is still a relatively novel concept and so far, all the announced projects deploy lithium-ion batteries. Since the application requires very fast response times but usually not very long storage durations, it is rather unlikely that the use as SATA is a promising business model for LDES technologies at large scale.

1.3 Regulatory best practices to support the deployment of LDES

By creating a market design that provides multiple revenue streams for LDES and introducing policies aimed at promoting energy storage, countries can strongly influence the attractiveness of LDES business models and thereby encourage deployment.

There are some general policies and regulations that are beneficial for all LDES business models. These include, for example, the complete elimination of disadvantages for energy storage with regards to grid charges, levies, and taxes. As a regulatory best practice, storage facilities can even be completely exempted from any levies (as in Germany and Italy). Another best practice is the formulation of an energy storage strategy including concrete deployment targets. These targets should ideally be differentiated according to storage duration to send a clear signal for the specific need for LDES. The Italian energy storage strategy can serve as a best practice in this regard.

In terms of market design, the establishment of capacity markets is conducive for LDES, as capacity contracts provide revenue certainty over a longer period and the storage depth of LDES is a competitive advantage over short-duration lithium-ion batteries. It is also important that the procurement of ancillary services is further liberalised and harmonised to reduce entry barriers for LDES. As more markets and services are opened to energy storage, regulators should also introduce clear rules and guidelines concerning the combination of various revenue streams (revenue stacking) to allow energy storage operators to maximise the revenue potential of their storage assets. This is important both to incentivise privately financed buildout (or at least lower the government support required) and to increase the overall economic value that storage assets can provide to the energy sector. All these aspects are particularly relevant for the stand-alone LDES business model, due to its focus on revenues from arbitrage and ancillary services. Within the geographic focus region of this report, these market design best practices are implemented to the highest degree in Great Britain.

To support the co-location business model, legislators should adopt policies that incentivise the build-out of hybrid plants (e.g., through specific auctions and by facilitating the permitting process). Such policies are in place in Germany, Italy, and Spain. Besides, regulators should set transparent guidelines for the market participation of co-located assets (e.g., for the participation in capacity markets). Finally, the EU requirement according to which co-located generators are not allowed to draw electricity from the grid if they are under a subsidy scheme could be reconsidered, as it severely restricts the possibilities of using the storage asset.

Policies and regulations can also have an impact on the attractiveness to install an energy storage facility for C&I companies. Policies that incentivise the self-generation of renewable electricity (e.g., through feed-in tariffs, net metering schemes or tax exemptions) are one option because energy storage systems are often used in conjunction with self-generation. Such policies are in place in all the countries evaluated in this study. Another way to incentivise the buildout of C&I behind-the-meter energy storage systems is to apply time-variable grid charges.

While the market design features and regulatory best practices mentioned above improve the market outlook for LDES, tailored financial support policies will be required to bridge the cost gap to established technologies and accelerate LDES deployment. Some of the countries that were examined in this study are already in the process of launching such support mechanisms or are considering it. As part of its energy storage strategy, the Italian government has announced to launch a dedicated auction mechanism for new-built storage assets with a targeted average storage duration of eight hours. In the UK, the government has launched a public consultation to collect views on facilitating the deployment of LDES and announced to assess the option of implementing a cap and floor subsidy mechanism. In France, a tender mechanism for energy storage has been announced (details are still pending, but it is unlikely to be an LDES-specific mechanism).

2. Introduction

2.1 Motivation for long-duration energy storage

As the world transitions towards a low-carbon energy system, the integration of renewable energy sources such as wind and solar into the power grid has become increasingly important. However, renewable energy sources are intermittent and often produce power when it is not needed, creating a mismatch between supply and demand. To address this issue, energy storage systems have emerged as a critical component of the modern power system, providing flexibility and reliability to the grid.

While short-duration energy storage systems such as lithium-ion (li-ion) batteries have been widely deployed, interest is growing for long-duration energy storage (LDES) technologies that can store energy for hours, days, or even weeks, responding to supply and demand variations caused by daily peaks, weather events and seasonal patterns. Thus, LDES can provide flexible but reliable generation, enable increased utilisation of renewables (e.g., by reducing their curtailment), decrease the necessary amount of dispatchable hydrogen or natural gas capacity, and enhance system stability and resilience. They can furthermore provide support for the overall increasing electricity demand due to the electrification of vehicles and industry in line with decarbonization.

Policy makers have recognised the need for LDES to support the integration of renewable energy into the power grid. However, the deployment of LDES projects is hindered by several factors such as high upfront costs, long lead times, a lack of revenue certainty, and missing market signals. Policy support and technological developments are necessary to address these challenges and enable the large-scale deployment of LDES projects.

2.2 Focus of the report

Aurora Energy Research (Aurora) was commissioned by SPRIND (Bundesagentur für Sprunginnovationen, Germany) to analyse the regulatory environment and potential business cases around LDES. The purpose of the analysis is to support start-ups with limited knowledge of the energy sector but promising technologies for LDES applications with identifying potential business cases.

In this study, LDES is defined as having a storage duration of at least ten hours (i.e., continuous withdrawal of energy from the storage for at least ten hours). The business models presented here are evaluated with regards to at least this storage duration. The analysis focuses on electricity storage or power-to-X applications, while thermal storage is not part of the focus.

Five European countries, i.e., Germany, France, Spain, Italy, and Great Britain, are analysed regarding their power market design and current interest in the market around LDES. The focus was set only on Great Britain and not on the United Kingdom, as Northern Ireland shares its electricity market with the Republic of Ireland. Furthermore, information on relevant EU regulation is provided.

2.3 Structure of the report

The analysis is structured into two main parts, first explaining the regulatory environment (chapters 3, 4 and 5) and afterwards analysing several potential business models (chapter 6).

As an introduction to the regulatory environment, chapter 3 provides an explanation of the general functionality of electricity markets. This chapter is aimed at a readership that is not yet familiar with electricity markets and wants to develop an understanding of the basic terminology and electricity market design in general.

Building on the information provided previously for electricity markets in general, chapter 4 explains how the markets in the five countries evaluated in this report are designed. While there are parallels (e.g., all evaluated countries have a wholesale market), significant differences exist (e.g., not all evaluated countries have a capacity market). Chapter 4 starts with an description of the regulatory environment on an EU level (chapter 4.1) and then provides details on the power market design and notable policies with a focus on LDES for Germany (chapter 4.2), Spain (chapter 4.3), France (chapter 4.4), Italy (chapter 4.5) and Great Britain (chapter 4.6).

To conclude the regulatory environment, chapter 5 describes further relevant regulation that is necessary to understand the business models presented afterwards, such as regulation regarding behind-the-meter set-ups (chapter 5.1), co-location (chapter 5.2) and grid charges for industrial consumers (chapter 5.3).

Finally, chapter 6 provides an overview of potential business models. Four main LDES business models have been identified for this analysis, i.e., stand-alone storage (chapter 6.2), co-location with renewable energy plants (chapter 6.3), behind-the-meter customer energy management (chapter 6.4) and storage-as-transmission asset for grid applications (chapter 6.5). For each business case, several applications are explained in detail. Furthermore, the potential for combining several of the applications is evaluated. Finally, an attractiveness assessment of the applications is provided and regulatory best practices in the evaluated countries are named.

The findings of the analysis are summarised in the conclusion (chapter 7).

3. Functionality of liberalised electricity markets

3.1 Considered countries

Common market rules in the European Union (EU) create market-based competition among suppliers and ensure cost-effectiveness, as well as ensuring non-discriminatory market access and enhancing market flexibility in light of the EU's decarbonization targets (such as the strong build-out of renewable energy sources). The increasingly integrated EU power market allows for cross-border cooperation among EU countries, so that energy can be produced in one EU country and delivered to consumers in another country.

Of the five countries considered within this report, four of them are EU members and therefore rely both on EU power market regulation and their own respective market regulations. This applies to Germany, France, Italy and Spain.

The fifth considered country, the United Kingdom of Great Britain and Northern Ireland, left the EU on 1 January 2021 and thus also the EU's internal energy market. Therefore, energy trading via electricity interconnectors is no longer managed through market tools like EU market coupling. Only Northern Ireland maintains part of the single electricity market with the Republic of Ireland.

Nevertheless, a significant number of electricity interconnections exists between Great Britain's power grid and those of various EU member states, e.g. France, Belgium, the Netherlands, and Ireland, as well as Northern Ireland. Therefore, post-Brexit framework agreements have been developed to ensure security of supply and continue EU-UK cooperation in the electricity sector. Notably, electricity trade across interconnectors with the United Kingdom does continue, but it is not as efficient compared to the single EU-internal system (EC 2023a).

The EU has set an interconnection target of at least 15% by 2030, in order to encourage EU countries to interconnect their installed electricity generation capacity. Increased market integration has a downwards effect on prices and helps to alleviate transmission constraints as well as grid congestion by exporting excess power into neighbouring countries.

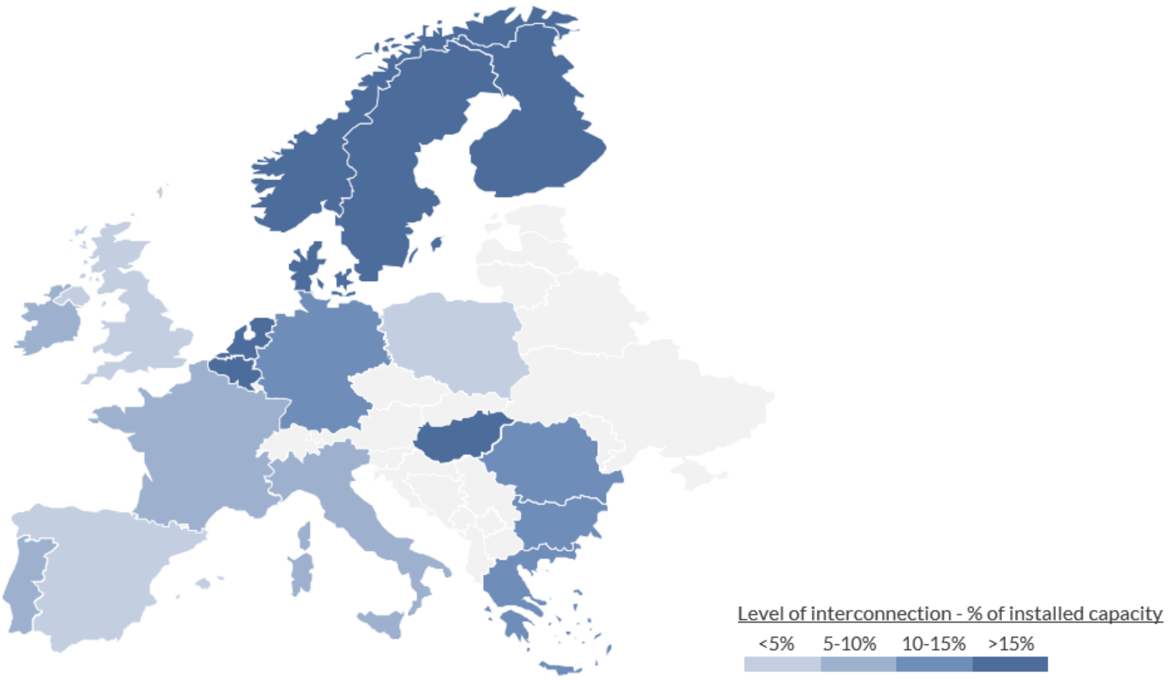

Figure 1: Level of interconnection in Europe

3.2 Market participant roles

Until the 1990s, the European electricity market was dominated by local monopolies. Utilities presided over these regional monopolies, where they encompassed the whole value chain of electricity, i.e.:

- *Generator*: Generating electricity by operating power plants.
- *Transmitter (grid operator)*: Building and operating the electricity grid, both the high-voltage transmission grid for large-distance transport and the lower-voltage distribution grid for regional transport.
- *Retailer*: Selling electricity to consumers via the retail market.

The European Union and its members states have since gradually liberalised their energy markets in order to allow for free competition. The market power of local monopolies was weakened, and new participants could enter the market. Specifically, the market roles of generator, transmitter and retailer were unbundled, allowing individual companies to (optionally) fulfil only one of those market roles, and subjecting existing monopolies to unbundling market rules in order to ensure discriminatory-free access to the grid as well as grid and retail consumer data.

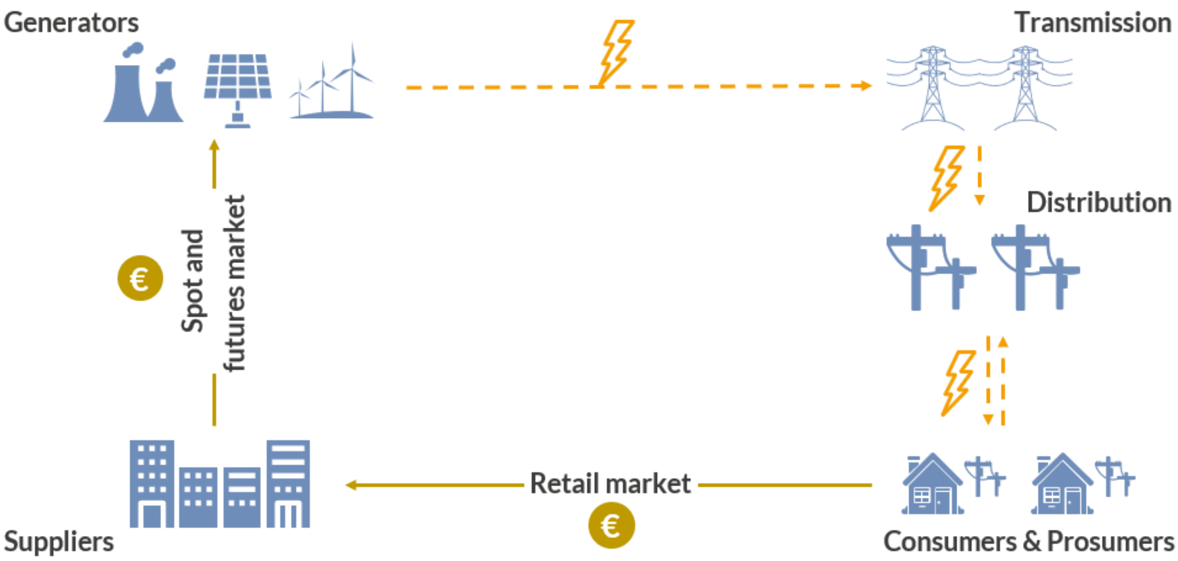

Figure 2: Liberalised electricity market exemplary structure

Selected directives include that e.g., prices are to be formed on the basis of demand and supply, consumers can act as prosumers and participate actively on the market, cross-border barriers are gradually removed, and electricity generators are directly or indirectly responsible for their electricity sales.

A market role that gained relevance after the liberalization of energy markets was the role of trading:

- *Trader*: Trading generated electricity on the wholesale market (i.e., spot and futures markets).

Other relevant market roles are:

- *Developer*: Building power plants.
- *Consumer*: Utilizing the bought and delivered electricity. Can also be a *prosumer*, when electricity is not only consumed, but also produced and fed into the grid.

The definition of these various market roles and their understanding will be relevant for the business cases outlined in chapter 6.

3.3 Market segments for electricity

The value of electricity varies by time and location – more so than for other commodities, as demand has to match supply at all times. The necessity of demand matching supply at any time is due to the fact that the grid frequency must be always kept at a level of 50 Hertz in Europe (e.g., North America has 60 Hz); otherwise, there would be the risk of a power outage.

This means that in times of low electricity generation but high demand, the value of electricity and thus also market prices will be very high, while in times of very high electricity generation but low demand, prices can even become negative, i.e., consumers will be paid to consume additional Megawatt-hours of electricity.

The different market segments account for these specific characteristics of electricity. Electricity can be traded there from several years up to only minutes prior to delivery. In addition to trading electricity on markets, other agreements (e.g., bilateral agreements such as power purchase agreements (PPAs)) are possible. Yet, the wholesale price often serves as the price reference in other contracts.

Generally, several different markets exist per country where it is possible to trade electricity. A schematic overview of possible market segments is shown in Figure 3. The following chapters will examine these market segments in detail.

It has to be noted that not all types of market segments exist in all countries, e.g., Germany has an energy-only market design with a capacity reserve, which means that a capacity market does not exist.

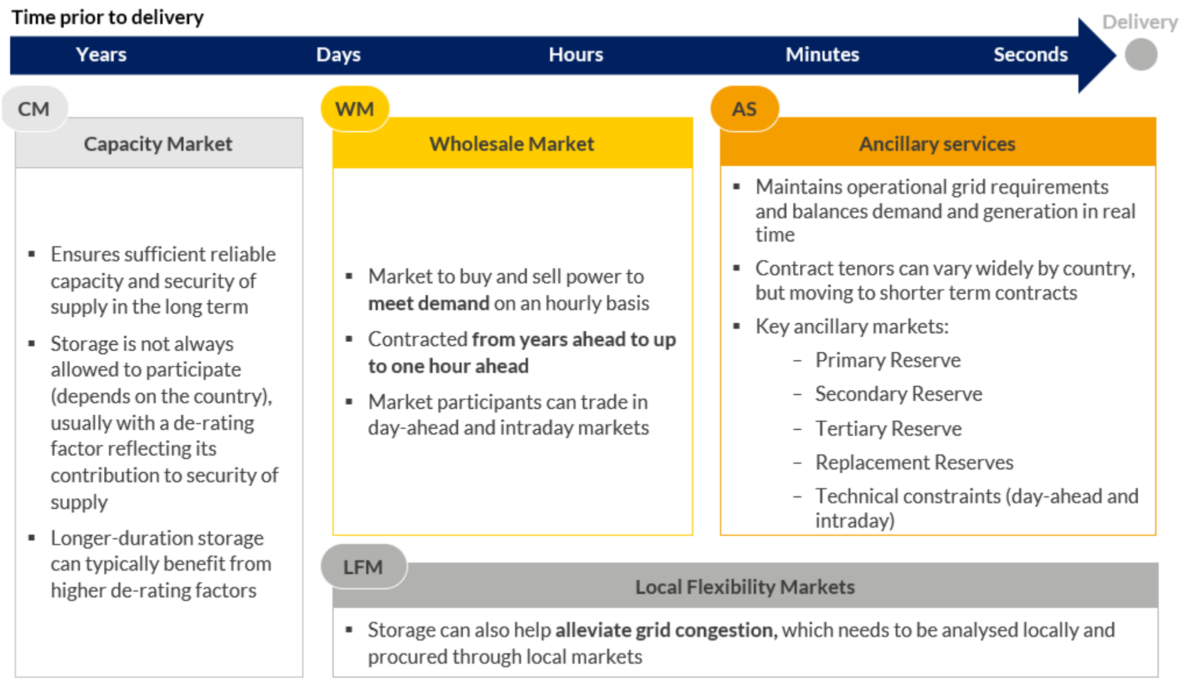

Figure 3: Schematic overview of (possible) market segments

The term **wholesale market** encompasses the long-term market segment of futures/forwards and the short-term market segments of day-ahead and intraday trading.

3.4 Spot market

3.4.1 Day-ahead market

On the day-ahead market, electricity is traded – as the name indicates – for the next day. It is operated through a blind auction which takes place once a day at noon. In this auction, all 24 hours of the following day are traded. Market participants place their buy or sell bids for each period, reflecting a specific volume and price.

For each hour, the *marginal costs* of a power plant are the costs of producing an additional unit of electricity. In a competitive electricity market, power generators bid to supply energy to the grid at the lowest possible price. The electricity market operator uses these bids to rank the available power plants in order of their marginal costs. The power plants with the lowest marginal costs are dispatched first to meet the current demand for electricity. As demand increases, power plants with higher marginal costs are dispatched in turn, until enough power is available to meet the demand ("*market clearing*").

This intersection of demand and supply curve determines the market clearing price ("*marginal price*" or "*spot price*") for each hour of the following day. That means that the market clearing price is determined by the most expensive plant still required to match demand and is received by all plants, independent of their original, potentially lower bids ("*pay-as-cleared*" principle).

This ranking of power generation sources based on their marginal costs is called the *merit-order principle*. A schematic visualization is shown in Figure 4.

By dispatching power plants in order of their marginal costs, the merit order principle helps to ensure that the available power supply is used as efficiently as possible. This can lead to lower costs for consumers and a more sustainable use of resources. For example, in a power system with a mix of coal, gas, nuclear, wind, and solar power plants, the merit order principle would dictate that wind and solar plants, which have almost zero marginal cost, are dispatched first, followed by nuclear, coal and gas plants in order of increasing marginal cost.

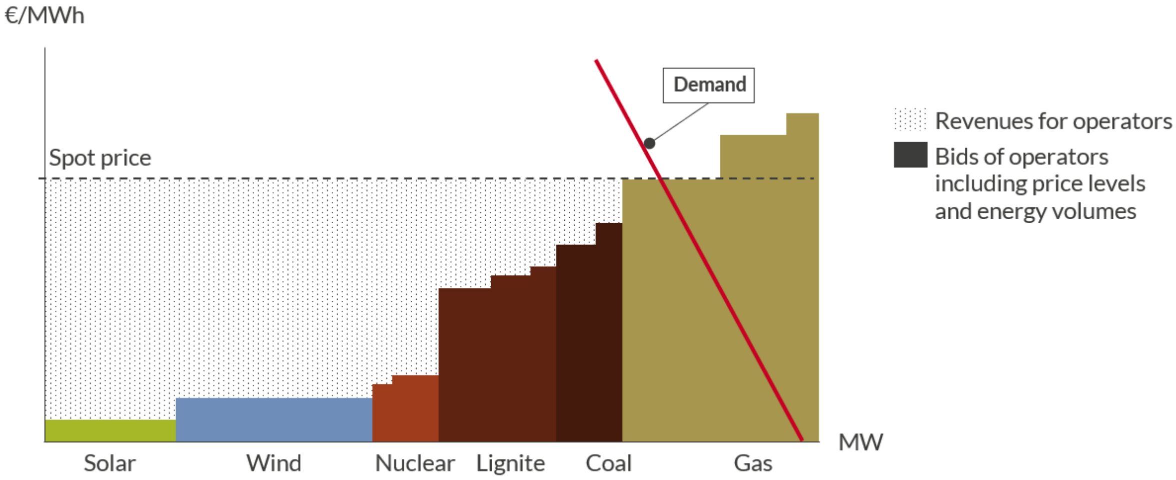

Figure 4: Schematic visualization of the merit order principle

All agreements resulting from the market clearing are legally binding based on the marginal price. All selling bids at a price lower than the marginal price are executed for their specified volumes and receive the overall marginal price; while all selling bids that are higher than the marginal price are excluded. Reversely, all purchasing bids at a price higher than the marginal price are executed for their specified volumes and pay the overall marginal price; and similarly, all purchasing bids for price levels lower than the marginal price are excluded. Buyers and sellers are not matched one-to-one in the auction.

Trading is organised by local power exchanges such as the European Power Exchange (EPEX) in the form of daily auctions.

In many markets, the day-ahead market is one of the main revenue sources for storage operators. They take advantage of different price levels at different hours of the day, buying energy at low-price hours, storing it and selling it at high-price hours. This exploitation of price deltas is called *arbitrage*.

3.4.2 Intraday market

Intraday trading allows for shorter-term finetuning to prevent imbalances. This is necessary as – with the approaching of the delivery timeframe – market participants have increasingly more information about their expectations for generation or purchase, such as a more detailed weather forecast and clearer expectations about wind or solar generation.

The intraday market opens after the day-ahead market is cleared – on the EPEX Spot, intraday trading opens at 3 p.m. on the previous day (gate opening time). It is then already possible to start placing bids for the selected day. However, intraday trading is possible up until a few minutes before delivery (e.g., for Germany, placing bids is possible up until five minutes before delivery on the EPEX Spot). This allows for a high level of flexibility and enables last minute adjustments, so that the positions of market participants can be balanced closer to real time. Trades are executed as soon as buy- and sell-orders match ("**pay-as-bid**" principle).

On the intraday market, participants trade continuously at all times of the day for delivery still on the same day. Depending on the country, intraday trading is done via continuous trading (as on a stock exchange), or also via auctions.

3.5 Ancillary services

A stable power system and reliable power supply requires that the frequency, voltage, and power load on the grid always remain within certain limits. To ensure that these requirements are fulfilled, system operators need to continuously apply small corrections. These system stabilising measures are often provided by market participants (generators, energy storage, demand-side response (DSR)) and therefore called system services or ancillary services. In the event of a blackout, ancillary services also help to restore the power system as quickly as possible. LDES could technically provide a range of ancillary services and use them as a revenue source. For the sake of simplicity, ancillary services are broadly divided in two categories in this study: (1) Balancing and frequency services and (2) other ancillary services.

The means by which transmission system operators (TSOs) procure ancillary services varies both between different types of services as well as between countries. In some instances, it is mandatory for power market players to provide ancillary services without remuneration. In other cases, the procurement is market-based or the TSOs engage in bilateral contracts. The costs for the procurement of system services are usually passed on to the market participants by the TSOs in the form of network charges.

3.5.1 Balancing and frequency services

Balancing and frequency services are essential components of a reliable and stable electricity grid and a key task of TSOs. Balancing services refer to the management of electricity supply and demand in real-time to ensure that the electricity grid remains in balance, i.e., the supply matches the demand at all times. This is critical to avoid power outages and blackouts. Frequency services are a subset of balancing services that are specifically focused on maintaining the frequency of the electricity grid within a narrow range around the nominal frequency (50 Hertz in Europe). Any deviation from this range can cause significant damage to electrical equipment and result in power outages. Both balancing and frequency services are provided by a combination of market participants, including power generators, electricity retailers, energy storage providers, and grid operators.

In many countries with a liberalised energy sector, the procurement of balancing and frequency services is organised via competitive auctions in which market participants are remunerated for offering reserve capacity and/or energy. Typically, auctions in which market participants offer to reserve a certain amount of capacity for balancing purposes take place day-ahead. On the delivery day itself, market participants can make bids to provide positive and/or negative balancing energy, depending on whether there is a lack or a surplus of power in the system. Most TSOs procure several frequency and balancing products which differ by their full activation time (FAT) following a frequency distortion and their duration. See Figure 6 for an overview of the balancing and frequency service products available in the countries evaluated in this study. A closer explanation of the individual services and market will be provided in chapter 4.

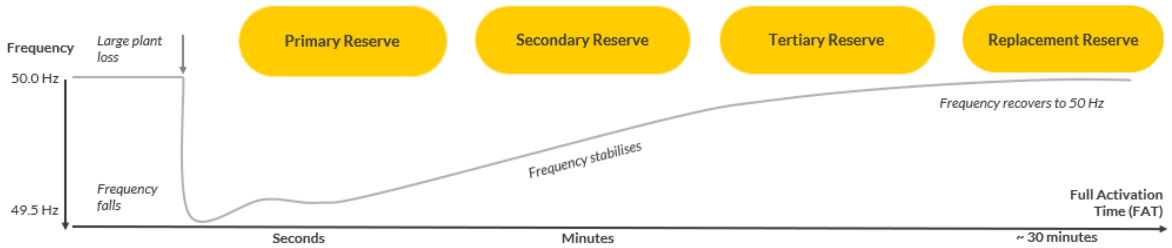

Figure 5: Schematic illustration of the functioning of frequency ancillary services

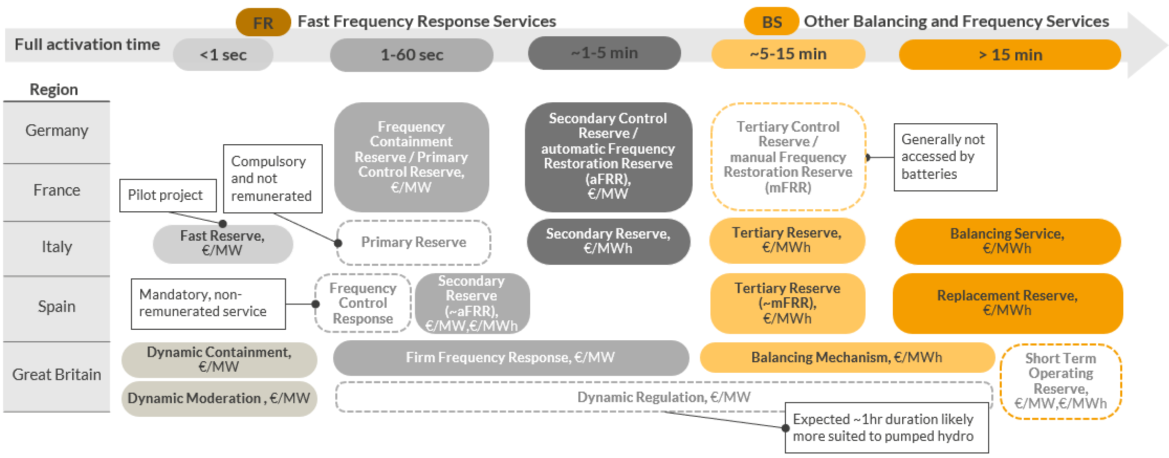

Figure 6: Market segments for frequency and balancing services in evaluated regions

3.5.2 Other ancillary services

Voltage control

Just like frequency, the voltage of the grid needs to be kept in a certain range to ensure the safe functioning of network equipment and final consumption devices. Grid operators procure voltage control services to be able to take countermeasures in the event of a sudden voltage drop (e.g., due to a short circuit) or excessive voltage.

Restoration of supply after a power failure (Black start)

In the event of a power failure, TSOs need to ensure that the power supply is reconstructed as quickly as possible. For this purpose, they mainly rely on power from generators that do not require an external source of electricity to ramp up production (*black start capability*). Since energy storage facilities generally fulfil this requirement, they could technically provide black start services.

Operational management and grid congestion management

The increasing share of renewable generators combined with growing electricity demand poses a challenge for the grid infrastructure in many countries. Especially in places where renewable generation is located at long distances from load centres, grid bottlenecks can become a problem (in Germany, for example, this problem occurs between the North, where a lot of renewable energy is generated, and the South, where less renewable energy is generated but a lot of industry is located). To avoid grid congestion, TSOs take congestion management measures to shift or "relocate" the production of electricity. In practice, this means that a power generator located in front of a grid constraint is asked to ramp down (or curtail) its production, while another generator located behind the bottleneck is instructed to increase its production. This form of congestion management is called redispatch or feed-in management.

In many countries, the costs associated with congestion management measures have increased significantly in recent years. To alleviate the problem, investments to strengthen the transmission and distribution grids are required. Besides the buildout of new power lines, energy storage facilities could be used for this purpose, e.g., by building a storage next to the renewable asset in front of the grid bottleneck.

Local flexibility markets

In local flexibility markets, local flexibility options based on distributed energy resources (e.g., batteries, other forms of storage, demand-side response) are used to feed in to or consume power from the local grid. The purpose of the local flexibility market is to alleviate grid congestion on a local level, minimise power outages and avoid grid expansions, thus supporting distribution grid operators (DSOs).

3.6 Capacity market

Unlike other markets presented here, remuneration in a capacity market is based on capacity (MW) and thus potential generation rather than actual generation (MWh). The purpose of a capacity market is to incentivise sufficient buildout of – usually dispatchable – capacity (e.g., gas, hydrogen, storage), which might not receive enough remuneration from other market segments (like the day-ahead market or balancing mechanisms). This insufficient incentivization of dispatchable capacity could take place as its profitability often relies on a certain share of high prices. The investment might be considered too insecure if the necessary prices are very rare and/or extremely high. Besides, even if those dispatchable plants are generating electricity, they often only receive a price which is close to their marginal costs and hence their gross margin might not be sufficient to cover their CAPEX and OPEX expenses. These aspects could then result in the medium- to long-term in overall insufficient investments in dispatchable capacity, which could cause a supply shortage and threaten security of supply.

Capacity markets tend to have a higher share of governmental market influence than other market segments, i.e., governments usually have decision authority on a large number of parameters, such as setting the capacity target and remuneration schemes. This is especially true for central capacity markets. In decentral capacity markets, each supplier sets the capacity target and suppliers are obliged to contract firm capacity up to their respective peak demand. Examples of countries with a central capacity market are Great Britain or Italy, while France has a decentral capacity market.

Generally, plants can simultaneously participate in the wholesale or other ancillary markets as well as a capacity market while ensuring availability of contracted capacity in scarcity events. If the procured capacity cannot be provided, penalties can be applied. The reliability of the contribution that different technologies can make to security of supply in tight hours is reflected in de-rating factors, which scale the nameplate capacity down so that more installed capacity is needed to meet the set capacity target. A high de-rating factor (e.g., 95%) means that a high percentage of the capacity remains after the de-rating factor has been applied. The impact of de-rating factors is also reflected in the respective capacity payment. For some capacity, such as duration-limited storage, the de-rating factor decreases as more of that technology is built, to reflect the technology's declining contribution to security of supply.

4. Regulatory implementation

This chapter discusses the specific national designs of the electricity markets and system services described in chapter 3 for the regions that fall in the scope of this study. In addition, the regulatory framework for LDES is evaluated for the respective countries. This assessment provides the basis for making comparative statements between countries concerning the attractiveness of LDES business models in the second part of the study.

4.1 Regulation on an EU level

4.1.1 Power market design and ancillary services

As described in the previous chapter 3, there are rules at EU-level with the purpose of creating a common electricity market between the Member States. In general, the EU, through directives and regulations on electricity market design, sets the framework within which member states can develop their respective energy market legislations.

Recently, the European Commission (EC) tabled a communication proposing to amend the Electricity Market Design Rules (EC 2023b). Contrary to earlier statements, the reform does not envisage any far-reaching interventions in the general functioning of the wholesale electricity market. A change of the marginal pricing mechanism (*merit order principle*) as proposed by some Member States is not foreseen. However, the proposal does contain some specific rules to promote the role of flexibility in the power system, which is relevant for LDES. These will be discussed in chapter 4.1.2.

Platforms	Target Services	Implementation status	Implications
PICASSO **P**latform for the **I**nternational **C**oordination of **A**utomated Frequency Restoration and **S**table **S**ystem **O**peration	For automatic Frequency Restoration Reserves – **aFRR**, or secondary control	Successful go-live June 2022; some countries have requested an exemption to postpone the go-live to Q4 2024 (Spain, Netherlands, etc.)	Balancing actions will be procured on a 15-minute basis, allowing for greater efficiency in balancing Europe's energy markets and benefitting more flexible asset classes. This added complexity will likely necessitate participants to utilise automatic bidding software.
MARI **M**anually **A**ctivated **R**eserves **I**nitiative	For manual Frequency Restoration Reserves – **mFRR**, or tertiary control	Successful go-live October 2022, most other participating countries to join in 2023 and 2024	
TERRE **T**rans-**E**uropean **R**eplacement **R**eserves **E**xchange	For Replacement Reserves - **RR**, also part of ENTSO-E's tertiary control	Live since Q1 2020, members include France, Spain, Italy and Great Britain, among others. However, not all TSOs in Europe use Replacement Reserves	TERRE will remove all Balancing and Settlement Code barriers to participants, increasing competitivity in RR auctions

Figure 7: Overview of cross-border platforms for frequency ancillary services

With regards to frequency and balancing markets, the 2017 EU Guideline on Electricity Balancing (EBGL) has set out the need to establish common principles for the procurement and settlement of frequency and replacement reserves[1]. The implementation of the EBGL requires that TSOs develop methodologies and submit their proposals to their national regulatory authorities for approval. Of the cooperation projects that have already been launched, the common market for procurement of and exchange of frequency containment reserves (FCR) is the most advanced. It was launched in 2017 and currently involves 11 TSOs from eight countries[2]. Figure 7 provides an overview of other cooperation projects.

4.1.2 Notable policies and regulations for energy storage

A major obstacle for the deployment of energy storage systems in Europe has been that the regulatory framework (both at the Member State and EU levels) was not fit for storage assets (Parra & Mauger, 2022). The main reason for this is that the rights and obligations were designed according to the "traditional" categories of electricity consumers and producers. As energy storage fulfils characteristics of both despite being a distinct asset class, this categorisation has led to regulatory uncertainty and double burdens. The main regulatory barriers can be differentiated into (1) lack of definition, (2) double charges[3], (3) unclear rules regarding the ownership and operation by system operators, and (4) an inadequate framework to allow for revenue stacking, i.e., the combination of multiple revenue streams (Dalton, 2019).

At EU level, many of these regulatory shortcomings were addressed in 2019 with the adoption of several regulations and directives as part of the so-called *Clean Energy Package*. The legislation package formally recognised the role of energy storage facilities for EU power markets and introduced new rules with the aim of removing deployment barriers and harmonising the regulatory framework across Member States.

Regulatory barrier	**Clean Energy Package provisions**
Lack of definition	Energy storage facilities are recognised as a distinct asset class, separate from generation, alongside a broad, technology-neutral definition of energy storage that includes not only electricity-to-electricity storage systems but also the conversion of electricity into other energy carriers (Art. 1, 2 of the Electricity Market Directive (EMD))[4].
Double charges	Member States have the responsibility to ensure that network charges do not discriminate either positively or negatively against energy storage (Art. 18 of the Electricity Market Regulation (EMR))[5].

[1] Regulation (EU) 2017/2195 (https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32017R2195&from=EN)

[2] Austria, Belgium, Switzerland, Germany, Denmark, France, the Netherlands, and Slovenia.

[3] Charges for both the electricity withdrawn from the grid and the electricity injected back into the grid.

[4] EU Directive 2019/944. Available online: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019L0944&from=EN

[5] EU Regulation 2019/943. Available online at https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943&from=EN

	System operators are instructed to ensure a non-discriminatory connection of new energy storage facilities to the grid (Art. 42 EMD).
Revenue stacking	Member States are instructed to provide the necessary regulatory framework to allow and provide incentives to grid operators to put in place procurement mechanisms for both frequency and non-frequency ancillary services that ensure an effective participation of energy storage facilities (Art. 31, 32, 40 EMD).
Ownership of system operators	As a general principle, storage assets should not be owned, developed, managed, or operated by TSOs and DSOs (Art. 36, 54 EMD). However, upon approval of the respective national regulatory authorities (NRAs), Member States may exceptionally allow system operators to own and operate storage facilities if they are fully integrated network components, or if the following conditions are fulfilled: ▪ An open tendering procedure for the provision of the storage service has been trialled and was not successful in delivering the required service at all or not at a reasonable cost and in a timely manner; ▪ The storage facilities are exclusively used by the grid operator to perform non-frequency ancillary services that are necessary for the fulfilment of its obligations and are not used to buy or sell electricity in power markets; ▪ The regulatory authority has conducted a necessity assessment including a review of the option to introduce a tendering procedure instead.

Table 1: Overview of main provisions on energy storage in the Clean Energy Package

Despite the progress made at EU level, there are still important differences regarding the regulation of energy storage between Member States. This is mostly because the *Clean Energy Package* has still not been fully transposed into national legislation. The delayed implementation of the EU regulatory framework for energy storage not only slows down the removal of regulatory hurdles, but the lack of clarity about which EU rules have already been implemented in a certain Member State creates additional uncertainty. One example of the implementation gap is the removal of double charges for grid usage. A recent report from the EU Agency for the Cooperation of Energy Regulators (ACER) on grid fees in Europe found that storage facilities are still subject to transmission and/or distribution charges for both grid withdrawal and injection in a third of EU Member States (ACER 2023). An assessment of the regulatory situation in each of the focus geographies of this study is part of the following chapters.

As far as future developments in energy storage legislation at EU level are concerned, the recently published Electricity Market Design Reform Proposal features three main proposals regarding energy storage:

- Flexibility support schemes: Member States need to create additional design features for flexible assets in capacity markets or can create specific flexibility support schemes to remunerate the available capacity of demand-side response and energy storage.
- Regular assessment of flexibility needs: Every two years, NRAs are asked to publish a report on the need for flexibility (DSR and energy storage) in their national electricity systems.

- National targets for energy storage: Based on the NRA's assessment of flexibility needs, Member States shall define indicative national objectives for the deployment of energy storage.

Another relevant piece of legislation is the recently published Delegated Act on renewable fuels of non-biological origin (RED II Delegated Act)[6]. The delegated act defines the criteria that producers of hydrogen must fulfil for their hydrogen to be labelled as 'green'. Although the regulation is of primary relevance for electrolyser operators, it does have implications for any LDES business models that involve the production and re-conversion of hydrogen via electrolysis. In general, there are three criteria that need to be fulfilled to obtain the green hydrogen label:

- Additionality: There must be a newly built renewable asset that comes into operation max. 36 months before the electrolyser. The renewable asset must not receive subsidies. Additionality is compulsory for assets that start operation after 1st January 2028.
- Geographic corelation: The renewable asset and the electrolyser should be geographically correlated (located within the same bidding zone or a neighbouring bidding zone).
- Temporal correlation: Power generation and hydrogen production must match in a certain timeframe (monthly until 2030, and hourly afterwards). A new-built electricity storage asset can be used to make the hydrogen production more flexible while adhering to the temporal correlation requirement.

Some hydrogen production business models are waived from some of the criteria (see Figure 8).

Business models that are waived from some of the criteria

Business model description	Addition-ality	Temporal correlation	Geographical correlation
A **Art. 3:** Electrolyser directly connected to a RES asset	Required		
B **Art. 4.1:** Electrolyser located in a bidding zone where average RES share in electricity mix exceeds 90%			Required
C **Art. 4.2:** Electrolyser located in a bidding zone with average grid carbon intensity less than 64.8 gCO_2/kWh		Required	Required
D **Art 4.3:** Electrolyser using power that would have been curtailed otherwise		Required	Required

Figure 8: Exceptions to the criteria for the production of green hydrogen

[6] Commission Delegated Regulation supplementing Directive (EU) 2018/2001. Available online: https://energy.ec.europa.eu/document/download/708bb80b-f844-4bc6-b53a-e0d730d4e74a_en?filename=C_2023_1087_1_EN_ACT_part1_v8.pdf

4.2 Regulation in Germany

4.2.1 Power market design and ancillary services

Germany has an Energy-Only Market (EOM) complemented by ancillary services markets and reserves. Within this market design, power providers are remunerated only for sold energy – there is no capacity market in place. To guarantee security of supply in case of exceptional and unforeseeable events, reserve capacities are held. However, the respective plants are not allowed to participate in the wholesale market.

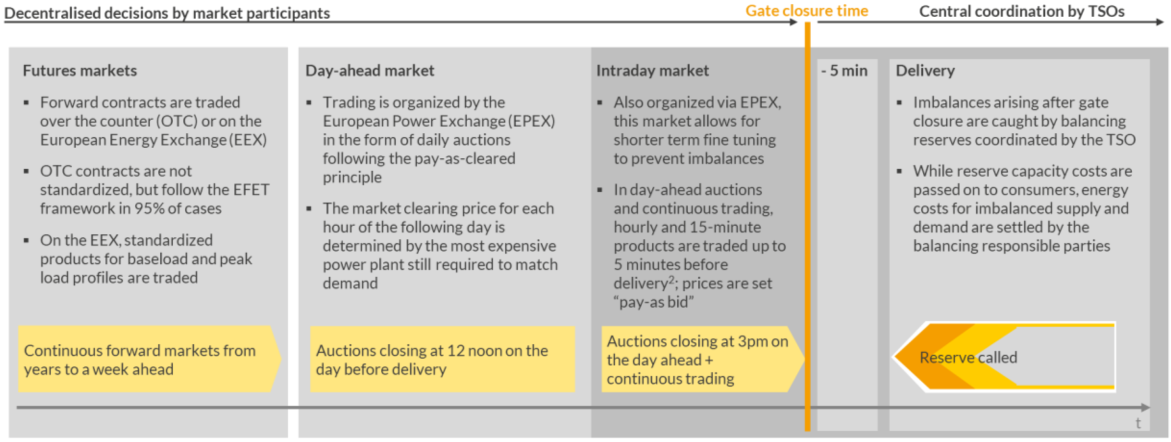

Figure 9: Overview of the German wholesale power market

The current government coalition considers a reform of the market design as rising electricity demand and a high share of renewable energy sources (RES) likely require capacity and flexibility remuneration and/or regulated scarcity pricing to ensure security of supply. To this purpose, the federal government has set up the dialogue platform *Plattform Klimaneutrales Stromsystem*, which is supposed to make concrete proposals for a revised market design. Even though it is not yet clear which market design changes the government will choose, there is a realistic possibility that a capacity market will be established.

There are three markets for the provision of frequency and balancing services in Germany: Frequency containment reserve (FCR), automatic frequency restoration reserve (aFRR), and manual frequency restoration reserve (mFRR). The main characteristics of the markets and the participation requirements are listed in Table 2.

	FCR	aFRR	mFRR
FAT	< 30 seconds	< 5 minutes	< 15 minutes
Deployment period	Up to 15 minutes	30 seconds to 15 minutes	15 minutes to 60 minutes
Remuneration	Capacity price	Capacity price and energy price	Capacity price and energy price

Minimum bid size	+/- 1 MW (symmetrical)	5 MW positive or negative[7]	5 MW positive or negative[8]
Products	Positive and negative: 6 4-hour segments per day	Positive and negative: 6 4-hour segments per day	Positive and negative: 6 4-hour segments per day

Table 2: Main characteristics of FCR, aFRR and mFRR markets

Most of the non-frequency ancillary services are not procured in a competitive market mechanism. However, the German NRA *Bundesnetzagentur* (BNetzA) has recently adopted a decision that mandates TSOs to introduce a market-based procurement mechanism for the black start service[9].

4.2.2 Notable policies and regulations for energy storage

Regulatory aspect	**Description**
Energy storage definition	A definition compliant with the EU Electricity Directive was introduced with the amendment of the Energy Industry Act (*Energiewirtschaftsgesetz*) in July 2022.
Access to electricity markets	Energy storage can participate in the day-ahead and intraday markets.
Provision of balancing and frequency ancillary services	Energy storage is in general eligible to participate in all balancing and frequency ancillary services markets. Pooling is allowed to fulfil prequalification requirements (i.e. to fulfil the 5 MW minimum bid size for aFFR and mFFR).
Provision of other ancillary services	TSOs procure non-frequency ancillary services either via bilateral contracts or the provision is mandatory for generators.
Specific value stacking guidelines / rules	N/A
Local flexibility services	Several local flexibility pilot platforms have been launched under the SINTEG programme of the German Ministry for Economic Affairs and Climate (EN-ERA, New 4.0, Designetz, WindNode).
Grid charges	In general, storage facilities are subject to withdrawal charges (ACER 2023). However, a specific regulation on grid fees and taxes is in place for energy storage assets built between 04 August 2011 and 04 August 2026. Such assets

[7] Smaller bids of min. 1 MW are allowed if a provider of aFRR submits only one offer per product segment and balancing zone.

[8] Smaller bids of min. 1 MW are allowed if a provider of mFRR submits only one offer per product segment and balancing zone.

[9] BNetzA Beschluss BK6-21-023. Available online at https://www.bundesnetzagentur.de/DE/Beschlusskammern/1_GZ/BK6-GZ/2021/BK6-21-023/BK6-21-023_Beschluss_vom_13.01.23.pdf?__blob=publicationFile&v=1

	are fully exempt from grid fees for the first 20 years of operation if the purpose of their power consumption is the storage and later feed-in of the consumed power.
Taxes & levies	Energy storage facilities are exempt from taxes and levies applied to their consumption due to storage losses if they are built between 04 August 2011 and 04 August 2026.
Energy Storage Strategy	An Energy Storage Strategy was announced by the government alongside the amendment of the Energy Industry Act, but has not been published, yet.
Buildout target	The government has not defined specific buildout targets for energy storage facilities.
Subsidy schemes for energy storage	The 2023 Renewable Energy Law (*Erneuerbare Energien Gesetz*) introduces tenders for innovative renewable energy concepts with local hydrogen-based electricity storage. Tenders are available for a total of 4.4 GW of unit combinations, comprised of onshore wind and/or solar plants with hydrogen-based electricity storage and plants for the reconversion to electricity. See chapter 5.2 for details of this support scheme.

Table 3: Collection of relevant legislation and regulations concerning energy storage in Germany

4.3 Regulation in Spain

4.3.1 Power market design and ancillary services

The electricity market in Spain is organised across several energy and ancillary services markets, taking place from months to minutes ahead of delivery.

	Days/months before delivery	Day before delivery		Days of delivery	
	Time to delivery →				
Market	Bilateral market	Day-ahead market	Day-ahead constraints and ancillary services markets	Intraday Market *(auction and continuous)*	Real time constraints and ancillary services markets
Product	Long-term/ financial contracts	Hourly energy (MWh)	Primary, Secondary, Tertiary and Replacement Reserve (MW/MWh)	Hourly energy (MWh)	Balancing up/down (MWh)

Figure 10: Overview of the wholesale power market in Spain

Since 2007, the Spanish and Portuguese electricity system are integrated and form the Iberian Electricity Market (MIBEL). The MIBEL day-ahead wholesale market has been coupled with Europe since 2014. Currently the Iberian market is an EOM, but the Spanish government proposed a capacity market mechanism in April 2021. Subject to approval from the European Commission, the capacity market mechanism may be approved by the end of 2024 with first capacity payments to be made in 2025. Some of the main design features of the capacity market were already outlined in the draft proposal (see Table 4). Parameters that have not yet been defined include the de-rating factors for eligible technologies.

Capacity market feature	**Description**
Auction design	Pay-as-bid auction
Settlement	Fixed monthly payment
Contract period	12 months for existing capacity, 5 years for new-built capacity
Eligible technologies	Generation technologies (incl. renewables), energy storage technologies, and DSR
Participation constraints	New-build capacity must be carbon neutral

Table 4: Key features of the proposed capacity market in Spain

The procurement of balancing and frequency ancillary services is structured in four reserve products. The Primary Reserve is a mandatory, non-remunerated service for all generation units (including energy storage). The remaining three reserves are market based and remunerated. Their main characteristics and the participation requirements are listed in Table 5.

In Spain, there is also a Technical Restrictions Market (TRM) in place for the management of grid congestions caused by technical limitations in the transmission or distribution network. The TRM allows generators, consumers, and other market participants to buy and sell contracts that provide the right to curtail or increase their power consumption or production when grid congestion occurs. This enables the system operator to maintain grid stability and avoid blackouts.

	Secondary Reserve	Tertiary Reserve	Replacement Reserve
FAT	< 20 seconds	< 15 minutes	< 30 minutes
Deployment period	20 seconds – 15 minutes	15 minutes – 2 hours	30 minutes – 1 hours
Remuneration	Capacity price	Energy price	Energy price

Table 5: Secondary, Tertiary and Replacement Reserve in Spain

4.3.2 Notable policies and regulations for energy storage

Regulatory aspect	**Description**
Energy storage definition	Royal Decree-Law 23/2020 formally introduced a definition of "subjects owning storing facilities" which is compliant with the electricity storage definition of the EU Electricity Directive (CMS Law 2022).
Access to electricity markets	Energy storage assets can participate in day-ahead and intraday markets. The proposal for the introduction of a capacity market foresees the participation of energy storage facilities (EnTEC 2023).
Provision of balanc. and frequency ancillary services	A resolution published by the NRA in December 2020 ensures the non-discriminatory access of energy storage to balancing markets (EnTEC 2023).
Provision of other ancillary services	Some non-frequency ancillary services such as voltage control are procured on the Technical Restrictions Market (TRM). Currently, energy storage facilities cannot participate on this market, but a reform was announced by the National Commission of Markets and Competition (CNMC) which will incorporate energy storage as service providers on the TRM (CNMC 2022).
Specific value stacking guidelines / rules	N/A
Local flexibility services	Congestion management services are procured through the Technical Restrictions Market. A reform is planned to allow energy storage to participate in this market (see *Provision of other ancillary services*).
Grid charges	The regulation of grid charges is very favourable for energy storage. Energy storage facilities are exempt from withdrawal charges. Since there is no tariff for injection in Spain, this means that storage assets are not subject to any network charges (ACER 2023).
Taxes & levies	Storage discharge is subject to the electricity production tax. Self-consumption installations under 100 kW are exempt (EnTEC 2023).

Energy Storage Strategy	An Energy Storage Strategy with various measures to increase the role of storage in the electricity system was adopted in February 2021[10].
Buildout target	The Energy Storage Strategy sets the objective of increasing the installed storage capacity from currently ~8 GW to 20 GW by 2030 and 30 GW by 2050
Subsidy schemes for energy storage	In 2021, the government announced to allocate funds to support the development of stand-alone and co-located storage installations with a commercial operation date until 2026 under the Spanish Recovery and Resilience Plan. At least 620mn € will be allocated to storage, flexible technologies, and new business models. The first call for R&D storage projects with a volume of 50mn € was announced in 2022 and a second one for co-located projects in the beginning of 2023 (150mn € volume). Another call for stand-alone projects with a volume of 150mn € is expected in 2023.
Other	In June 2022, the government announced a tender scheme for grid connection capacity. The first auction will award 5.8 GW of grid capacity to applicants following a points-based system. The criteria for the point allocation incentivise the deployment of energy storage facilities because around 20 % of the points are related to the project having storage sized up to 5 % of its capacity (Solar Power Europe 2023). The official timeline for the tender has not been published yet.

Table 6: Collection of relevant legislation and regulations concerning energy storage in Spain

[10] *Estrategia de Almacenamiento Energético*. Available online (in Spanish) at https://www.miteco.gob.es/es/prensa/estrategiaalmacenamiento_tcm30-522655.pdf (accessed on 13 April 2023).

4.4 Regulation in France

4.4.1 Power market design and ancillary services

In France, the wholesale electricity market is complemented by a capacity market. The capacity market was introduced in 2017 to tackle security of supply concerns arising from increasing peak demand during winter. In contrast to the centralised approach to capacity procurement taken by other countries, France has opted for a decentralised capacity market. This means that capacity providers (electricity generators and demand-side response) sell capacity certificates directly to obligated parties (mainly electricity suppliers[11]) either bilaterally (OTC) or on a certificate exchange platform.

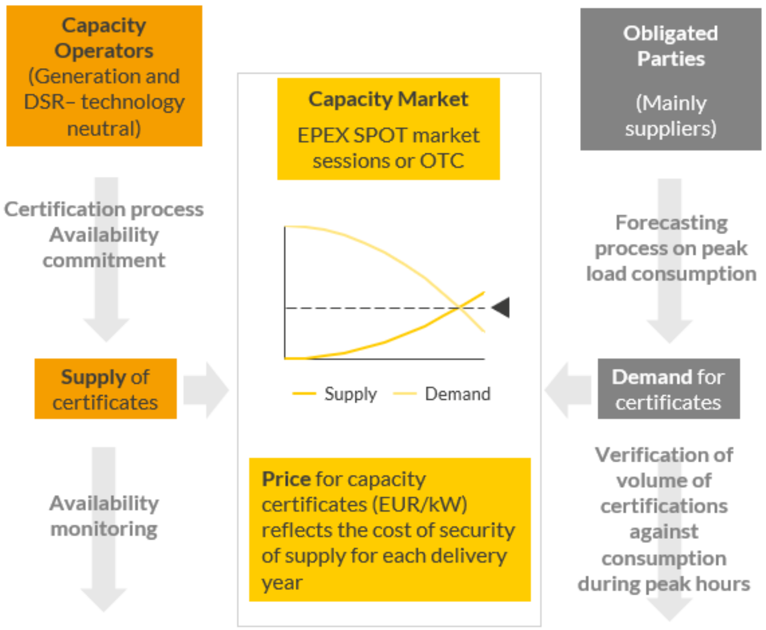

Figure 11: Functioning of the French capacity market

The French TSO, RTE, has defined ranges for technology-specific derating factors for the determination of generators' available capacity. Batteries were given a reference derating factor of 70% with an acceptable deviation margin of +/- 30 % for self-disclosed availability[12]. The minimum capacity required to participate in the capacity market individually is 1 MW, aggregation is possible.

There are currently four balancing and frequency services in France: FCR, aFRR, mFRR and Replacement Reserve (RR). FCR, mFRR and RR are procured market-based while aFRR is a mandatory service for generators with a capacity greater than 75 MW[13]. However, the aFFR service is currently undergoing a reform. aFRR energy will be procured through a tender platform from November 2023

[11] Besides electricity supplies, obligated parties are system operators and end consumers who do not fulfil their consumption from a supplier for all or part of their consumption.

[12] When a capacity provider wants to use the self-disclosed availability methodology ("méthode de calcul basée sur le réalisé"), it has to respect the certification tunnel defined as RTE reference derating factor +/- RTE derating factor acceptability margin. Certification outside the certification range remains possible but will have to be subject to a derogation procedure.

[13] They are required to participate to at least 4.5 % of their installed capacity.

(by connecting to the multinational PICASSO platform, see Figure 7 in chapter 4.1.1), while a shift to a national pay-as-clear auction for aFRR capacity is expected for July 2024. Table 7 provides an overview of the characteristics and participation requirements.

	FCR	aFRR[14]	mFRR	RR
FAT	< 30 seconds	< 400 seconds[15]	< 13 minutes	< 30 minutes
Minimum activation period	Up to 15 minutes	Up to 15 minutes	2 hours	90 minutes
Remuneration	Capacity price	Capacity price and energy price	Capacity price and energy price	Capacity price and energy price
Product duration	4 hours	1 hour	Day, year	Day, year

Table 7: Balancing and frequency services in France

4.4.2 Notable policies and regulations for energy storage

Regulatory aspect	**Description**
Energy storage definition	Energy storage facilities are defined in the Ministerial Order of 7 July 2016. The definition refers to power-to-power storage only.
Access to electricity markets	Energy storage facilities can participate in day-ahead, intraday, and capacity markets.
Provision of balancing and frequency ancillary services	Energy storage facilities can participate on the FCR, mFRR, and RR markets. There is currently no market-based procurement of aFRR in place. aFRR energy will be procured through a market from November 2023 (through PICASSO), while a market for aFRR capacity will be launched in July 2024.
Provision of other ancillary services	There is no black start service in France. Energy storage is not allowed to provide voltage control at transmission-level (EnTEC 2023).
Specific value stacking guidelines / rules	N/A
Local flexibility services	Pilot projects for the procurement of local flexibility services in dedicated areas have been launched on both the transmission system level and the distribution system level by the TSO RTE and the DSO Enedis (EnTEC 2023).

[14] Applicable once the reform is completed.

[15] To be changed to < 300 seconds from 18 December 2024 onwards.

Grid charges	The rules for grid charges are not fully comply with the EU requirement of avoiding double charge because transmission grid-connected storage assets are subject to both withdrawal and injection charges[16]. Storage facilities connected to the distribution grid are subject to withdrawal charges only (ACER 2023).
Taxes & levies	Taxes and levies need to be paid for the electricity withdrawn from the grid. The stored electricity is exempted from the tax on final electricity consumption (EnTEC 2023).
Energy Storage Strategy	There is currently no dedicated strategy for the deployment of energy storage in place. However, energy storage is covered extensively in the French National Energy and Climate Plan (NECP).
Buildout target	There is currently no energy storage deployment target in France apart from the objective set in the Multiannual Energy Plan for 2019-2028 to commission 1 to 2 GW of additional PHS plants until 2035[17].
Subsidy schemes for energy storage	In August 2021, the French Parliament adopted the Climate and Resilience Act. Article 85 created a new provision in the French Energy Code, which defines a regulatory framework for an electricity storage tender mechanism. The framework does not yet include a definition of the storage technologies which would be eligible to participate, nor a specific timeline. According to Decree No. 2022-788 from May 2022 which specifies how the tender mechanism will be implemented, draft specifications for the tender mechanism are to be drawn up by RTE, before being submitted to storage professionals for consultation. There is no specific timeline for the tender process, but observers assume that the first calls for tenders could be announced soon (White & Case 2022).

Table 8: Collection of relevant legislation and regulations concerning energy storage in France

[16] Although it must be noted that most energy storage facilities are currently connected to the distribution grid. A transmission grid connection would only be necessary for large-scale storage assets.

[17] *Programmation pluriannuelle de l'énergie (2019-2028)*, available online at https://www.ecologie.gouv.fr/programmations-pluriannuelles-lenergie-ppe, accessed on 19 April 2023.

4.5 Regulation in Italy

4.5.1 Power market design and ancillary services

In Italy, generators sell electricity on three key wholesale energy markets: The daily products market (MPEG), the day-ahead market (MGP), and the intraday market. Two systems of capacity payments, the essential units, and the capacity market, are set to ensure security of supply.

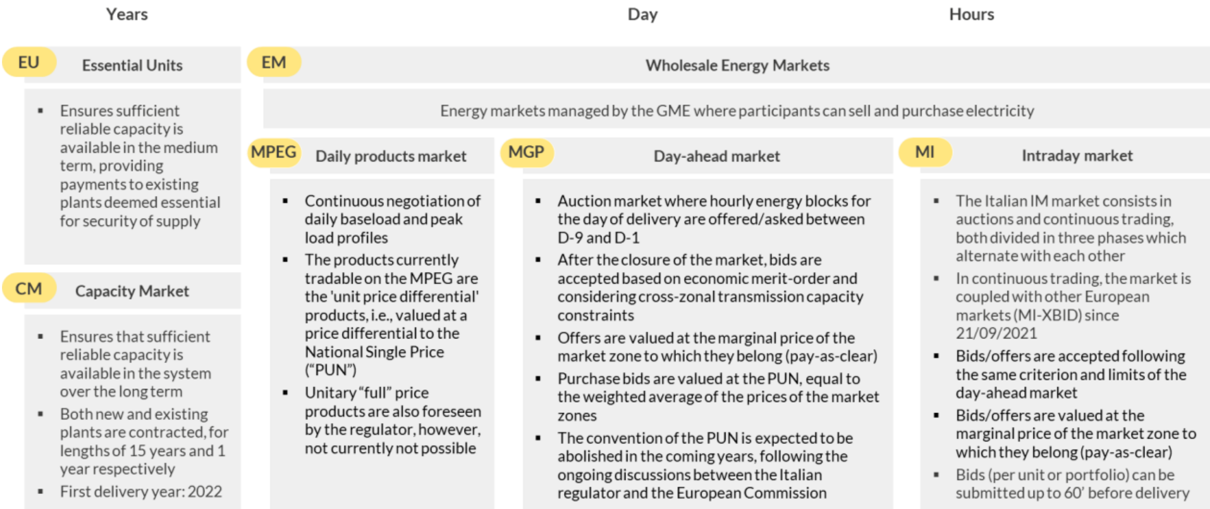

Figure 12: Overview of the wholesale power market in Italy

Due to transmission constraints, the power market is divided into seven price zones. Consumers face a single national purchase price across all zones (*Prezzo Unico Nazionale*, PUN), calculated as the weighted average of prevailing prices in the different zones. Generators receive the respective zonal price for the zone they are located in. The Italian government is evaluating the removal of the PUN, which would lead to consumers being exposed to zonal prices and potentially provide better price signals to demand.

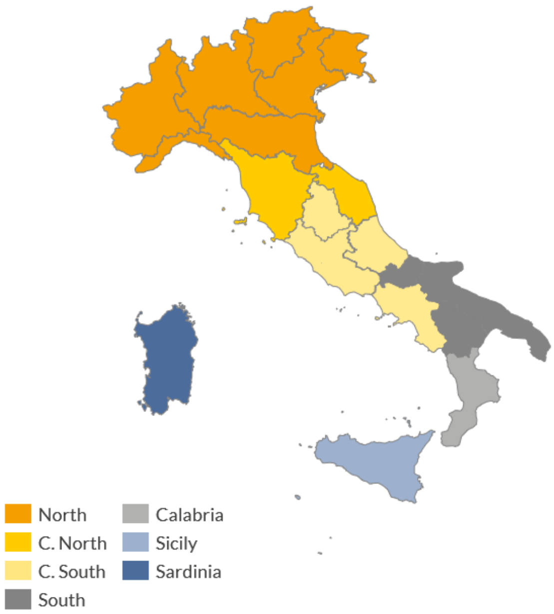

Figure 13: Market zones in Italy

Participation in the Italian market for frequency ancillary services (*Mercato Servizi di Dispacciamento*, MSD) is currently only possible (and mandatory) for conventional dispatchable production units. However, since 2017, a series of pilot projects have allowed new categories of resources (including electricity storage facilities) to participate in the MSD. Other ancillary services are currently not marketed nor remunerated and are made compulsories for all eligible generation units (energy storage and intermittent renewables are not eligible).

Capacity market contracts are awarded with durations of 1 and 15-years for existing and new-builds, respectively. Contracts can be closed through three competitive auctions:

- Mother (T-4) auction, up to 4 years ahead of delivery
- Adjustment (T-3) auction, up to 3 years ahead of delivery
- Secondary market for renegotiation of monthly positions, held a few days before delivery

Capacity market payments to capacity providers depend on the auction clearing price and technology-specific de-rating factors. The average de-rating factors for energy storage technologies in the 2024 T-4 capacity market auctions varied largely with storage duration. 8-hour batteries were granted a 90% de-rating factor on average while 1-hour batteries only were de-rated to 24% available capacity on average.

4.5.2 Notable policies and regulations for energy storage

Regulatory aspect	Description
Energy storage definition	Storage systems were defined as a distinct energy asset class by the Italian Regulatory Authority for Energy, Networks, and Environment in resolution no. 574/2014/R/eel.
Access to electricity markets	Energy storage can participate in the day-ahead, intraday and the capacity market.
Provision of balancing and frequency ancillary services	Since 2017, the MSD is partially open to energy storage assets via pilot projects. One of these pilot projects is the Fast Reserve, which is tailored on the provision of frequency regulation from energy storage assets. In 2023, the MSD is expected to be fully opened to energy storage technologies.
Provision of other ancillary services	Non-frequency ancillary services are not marketed nor remunerated and made compulsories for all eligible generation units.
Specific value stacking guidelines / rules	N/A
Local flexibility services	Two local flexibility services initiatives (EQUIGY and Platone) have been launched in Italy (EnTEC 2023).
Grid charges	The regulation of grid charges is very favourable for energy storage. Storage facilities are exempted from the application of grid tariffs and charges for electricity withdrawn and subsequently re-injected into the grid (ACER 2023).
Taxes & levies	In general, energy storage is subject to the electricity consumption tax. Electricity storage for self-consumption is exempt from taxes (EnTEC 2023).

Energy Storage Strategy	In 2021, the Italian government signed decree no. 210/2021 that defines the development of storage capacity in Italy[18].
Buildout target	Based on decree no. 210/2021, the Italian TSO Terna developed a scenario to determine the required storage capacity and identified a need for 15 GW by 2030. Of these 15 GW, 9 GW should be energy storage facilities with a targeted average storage duration of 8 hours.
Subsidy schemes for energy storage	The storage strategy includes a dedicated auction mechanism for new-built storage assets with a targeted average storage duration of 8 hours. While details are still pending, it is expected that multiple auctions with varying levels of required minimum storage durations will be held (for example an auction for a certain amount of capacity of storage assets with a 6-hour duration and a separate auction for storage facilities with a 10-hour duration). The awarded capacity receives annual capacity payments for the entire investment horizon, with the purpose of covering all capital and operational costs, including the remuneration of invested capital. Participants of the auction scheme will have to provide time-shifting products and ancillary services through a centralised platform.

Table 9: Collection of relevant legislation and regulations concerning energy storage in Italy

[18] Legislative decree 210/2021 transposing EU Directive 2019/944.

4.6 Regulation in Great Britain

4.6.1 Power market design and ancillary services

In Great Britain, assets participate in four key markets: The wholesale market, the capacity market, the balancing mechanism, and the ancillary services market. In addition, assets have access to local flexibility markets and embedded and behind-the-meter benefits.

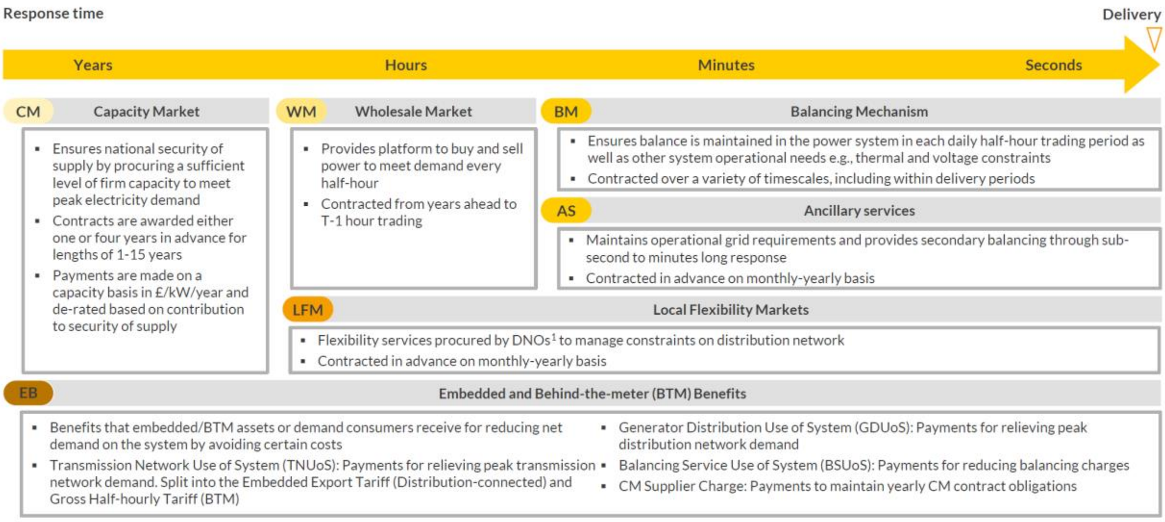

Figure 14: Overview of market segments in Great Britain

The Balancing Mechanism is used for last minute adjustments to match supply to demand. Parties submit notices to either generate more or less than initially contracted in the form of offers and bids. Offers are made for an increase of generation or a reduction of demand. Bids are made for a reduction of generation or an increase of demand.

There are currently four frequency response services that are procured on a tender basis: Firm Frequency Response (FFR), Dynamic Containment (DC), Dynamic Moderation (DM), and Dynamic Regulation (DR). DC, DM, and DR were launched in the last two years to gradually replace FFR which will be phased out until April 2024. The three new frequency response products can be divided into two broad categories: DC and DM, which require fast response times but low delivered volumes, and DR, which requires slower response times but higher throughput per MW of capacity. Table 10 provides an overview of the key requirements for the provision of the respective frequency response services.

	DC	DM	DR
FAT	< 1 second	< 1 second	< 10 seconds
Minimum activation period	30 minutes	30 minutes	1 hour
Throughput	~0.1 h/day in either direction	~0.5 h/day in either direction	~2.5 h/day throughput in either direction
Procurement	Daily tenders	Daily tenders	Daily tenders
Payments	Availability payment (£/h)	Availability payment (£/h)	Availability payment (£/h)

Table 10: Frequency response services in Great Britain

Great Britain is the most advanced of the countries considered in this study concerning the market-based procurement of other ancillary services. A competitive tender system is in place for the provision of black start energy. Besides, the TSO National Grid ESO has launched pilot projects for the tender-based procurement of voltage control and constraint management services (*Pathfinder projects*)[19].

In the British capacity market, prospective capacity providers make bids to secure monthly availability payments for keeping generation capacity ready for a response within each tendered year. Two auctions are held per year to disburse capacity contracts for one and four years ahead of delivery (T-1 and T-4 auctions). Capacity market contracts are awarded in durations of up to one, three, and 15 years for existing, refurbishing, and new build assets, respectively.

De-rating factors for energy storage technologies vary significantly depending on the storage duration. In the 2026/27 T-4 auction, storage de-ratings ranged from 5.95% for assets with a 0.5-hour storage duration to 95.25% for assets with a 9.5-hour duration.

4.6.2 Notable policies and regulations for energy storage

Regulatory aspect	Description
Energy storage definition	Currently, the UK legislative framework for the energy sector does not contain a specific framework for energy storage (Morgan Lews 2023). In 2020, Ofgem clarified that electricity storage falls under the category of electricity generation for the purposes of the 1989 Electricity Act[20] . To remove the current ambiguity, the government has tabled the 2023 Energy Security Bill, which would define electricity storage as a distinct subset of electricity generation in the 1989 Electricity Act (BEIS, 2023). The bill has yet to be adopted.
Access to electricity markets	Energy storage can participate in wholesale markets and the capacity market.
Provision of balancing and frequency ancillary services	Energy storage can participate in the balancing mechanism and in the frequency ancillary services markets.
Provision of other ancillary services	TSO National Grid ESO has launched a series of tenders (*pathfinder projects*) for voltage control, congestion management, and system restoration services which are open to energy storage assets.
Local flexibility services	There are six local flexibility tenders on the DSO level with four standardised products for flexibility services, respectively. Energy storage facilities can participate in these tenders.

[19] For more information, see National Grid ESO website at https://www.nationalgrideso.com/industry-information/balancing-services/pathfinders, accessed on 13 April 2023.

[20] The Electricity Act 1989 is the main piece of legislation governing electricity in Great Britain.

Specific value stacking guidelines / rules	National Grid ESO has put in place rules that govern the value stacking options for the provision of balancing and frequency ancillary services (National Grid ESO 2020)
Grid charges	Transmission-connected energy storage facilities face a withdrawal charge for the use of the transmission grid (Transmission Network use of System (TNUoS) charge). Distribution connected energy storage assets are subject to fixed and volumetric withdrawal charges for the use of the distribution grid (Distribution Use of System (DUoS) charge) and TNUoS. For the injection of electricity, distribution connected storage assets can receive so-called embedded benefits (consisting of the Generation Distribution Use of System (GDUoS) credit for the distribution grid and the Embedded Export Tariff for the transmission grid).
System operator ownership rules	TSOs are not allowed to own or operate energy storage assets (Gissey at al. 2016). Following a decision on changes to the electricity distribution license issued by the NRA Ofgem which took effect in April 2019, DSOs are also prohibited from carrying out storage activities, "unless the activity is captured by an exception, or the licensee has been issued with a direction" (Ofgem 2019).
Energy Storage Strategy	There is currently no specific strategy for the deployment of energy storage in place. However, in the Smart Systems and Flexibility Plan 2021, the UK Government and Ofgem set out a suite of policies to drive a net zero energy system by supporting flexible technologies, including electricity storage (BEIS & Ofgem 2021). Among other commitments, this entails a pledge to "create a best-in-class regulatory framework for electricity storage" and to provide innovation funding for "first-of-a-kind longer duration storage technologies" by the mid-2020s.
Buildout target	The Smart Systems and Flexibility Plan 2021 mentions that electricity storage should be scaled up to "around 13 GW "of capacity by 2030 in combination with flexible demand.
Subsidy schemes for energy storage	See *LDES specific policies* below
LDES specific policies	Similar to the SPRIND LDES challenge in Germany, the UK Government has launched a LDES competition in 2021 with up to 68mn £ capital funding available across 2 competition streams (UK Government 2021). In 2022, the UK Government launched a public consultation to collect views on facilitating the deployment of long-duration large-scale storage (LLES). In response to the consultation, the Department for Business, Energy and Industrial Strategy (BEIS) acknowledged that LLES "faces significant barriers to deployment under the current market framework" (BEIS 2022). To improve the situation, BEIS announced to assess the option of implementing a cap and floor subsidy mechanism for LLES. In more general terms, BEIS committed to developing an enabling policy environment for scaling LLES investment by 2024.

Table 11: Relevant legislation and regulations regarding energy storage in Great Britain

5. Other relevant regulation

5.1 Prosumers and behind-the-meter

For commercial and industrial (C&I) companies, LDES could be used in conjunction with facilities for self-generation of electricity (e.g. rooftop solar PV). For this business model, any regulations concerning the self-generation and storage of electricity are of relevance.

As for energy storage, the relevant pieces of legislation for electricity prosumers at EU level are the Electricity Market Directive (EMD), the Electricity Market Regulation (EMR), and the Renewable Energy Directive (RED). In general, Member States need to ensure that "final consumers are entitled to act as active customers without being subject to disproportionate or discriminatory technical requirements, administrative requirements, procedures and charges, and to network charges that are not cost-reflective" (Art. 15 EMD). In addition, Member States are obliged to ensure that prosumers can carry out several specific activities:

- Operate directly or through aggregation;
- Participate in flexibility schemes and energy efficiency schemes;
- Install and operate energy storage facilities without being subject to any double-charges;
- Store and sell excess production of self-generated renewable electricity, including through PPAs;
- Provide several services simultaneously, if technically feasible

The EU Member States covered in this study have already incorporated this provision into national law (EnTEC, 2023). There are no specific provisions concerning the self-consumption and storage of electricity in the UK 1989 Electricity Act.

Many countries have introduced subsidy schemes to incentivise the self-generation of electricity mainly by supporting the buildout of rooftop solar panels with feed-in tariffs and/or net metering schemes. Table 12 gives an overview of the support schemes that are in place in the countries considered in this study.

Country	Prosumer support policies
Germany	▪ Feed-in tariff for solar plants with a capacity of smaller or equal to ≤100 kW (6.20-8.60 ct/kWh, depending on plant capacity) ▪ Non-auctioned market premium scheme for solar installations smaller than 1000 kW but larger than 100 kW (6.20 ct/kWh) ▪ Revenues generated from small solar PV installations with a maximum capacity of 30 kW are exempt from income taxes
France	▪ Feed-in tariff for solar plants installed on buildings, sheds, or shades with a capacity of less than or equal to 500 kW
Italy	▪ Premium tariff: Producers with an installed capacity of maximum 100 kW are guaranteed a minimum price ▪ Net metering scheme for installations with a capacity of up to 500 kW that allows prosumers to offset the electricity produced and fed into the grid with the electricity taken from the grid. Remuneration is based on the net value of energy consumed minus energy sold.

Spain	▪ Surplus generation is remunerated through a reduction of monthly electricity bills for installations below 100 kW ▪ In 2021, the Spanish government has approved a Self-Consumption Roadmap with the aim of promoting the installation of renewable capacity for the purpose of self-consumption. The measures announced include: ○ Six support programmes for solar PV self-consumption with a total budget of 900mn € ○ 220mn € of support for behind-the-meter storage systems
Great Britain	▪ A feed-in tariff scheme was in place until 2019 and was since replaced by the more market-based Smart Export Guarantee (SEG) scheme ▪ Under the SEG, large electricity suppliers are obliged to offer small-scale generators (up to 5 MW) a price per kWh for the electricity they feed into the grid ▪ Since the duration and price are determined market-based and differ between suppliers, the SEG does not offer the same security of contract duration or guaranteed price floor as the feed-in tariff scheme

Table 12: Overview of prosumer support policies in selected countries

Concerning upcoming policy changes, the REPower EU Plan published by the EC in May 2022 contains a proposal to make installations of solar panels on new buildings mandatory (EC 2022). According to the proposal, new large (more than 250 m^2) commercial and public buildings would have to be equipped with rooftop solar installations by 2026 and existing buildings of the same type by 2027. The legislative proposal is currently being negotiated between the European Parliament (EP) and the Council of the EU (Council). The EP supports the timeline proposed by the EC while the Council favours a less ambitious timeline.

5.2 Co-location

Co-location or hybridisation describes the combination of a storage unit and a renewable asset (usually solar PV or onshore wind), which for example share a grid connection or are located behind-the-meter.

It must be noted that in terms of subsidies, a behind-the-meter, co-located storage and renewable asset combination is not allowed to charge from the grid and at the same time receive governmental support schemes (e.g., a feed-in tariff) under current EU regulation[21]. This is because electricity from the grid is not necessarily renewable (“green”) but usually a mix of various sources (“grey”), and so, the “green” and “grey” energy in the storage unit cannot be separated. Yet, “grey” electricity cannot receive subsidies under renewables support schemes. In result, if co-located, behind-the-meter asset combinations want to be eligible for governmental support schemes, they cannot provide grid services that involve charging from the grid, such as bi-directional frequency response services. This issue can be avoided if

[21] European Commission: Climate, Energy and Environmental State Aid Guidelines (CEEAG), section 2.4, par 19(35). Available online at https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52022XC0218(03)&from=EN.

the storage is set up independently, so that it does not share the connection, metering equipment and scheduling with the renewable asset. However, these two assets are then essentially separate units.

In some countries, specific co-location support schemes are available, as described in Table 13.

Country	Co-location support policies

Germany	▪ Innovation tenders which allow for a combination of new-built renewable and storage assets
	  ○ At least one renewable asset must be onshore wind or solar PV
	  ○ The storage asset must have a minimum 2h duration, and a capacity of at least 25% of the installed total capacity of the asset combination
	  ○ The assets are required to use a single grid connection point
	  ○ If a tender is won, the asset combination is eligible for a fixed feed-in premium (maximum value of 7.42 €/MWh in 2022), while the EEG 2023 changes to a flexible market premium
	▪ Additionally, in the EEG 2023 a third auction segment is planned targeting innovative concepts, in particular plant combinations of renewables with local hydrogen-based electricity storage
	  ○ Tenders for a total of 4.4 GW of unit combinations, comprised of onshore wind and/or solar plants with hydrogen-based electricity storage and plants for the reconversion to electricity
	  ○ Hydrogen to be exclusively generated via electrolysis with electricity from coupled renewables units and to be exclusively used for electricity generation
	  ○ Tender details to be specified in further ordinance

France	▪ No specific support schemes for co-location encountered
Italy	▪ Capacity market: Batteries that are co-located with another plant can participate in the capacity market (de-rating is calculated for the technology-specific capacity and then summed up for both battery and generating asset) ▪ Pilot project under Resolution 300/2017 (UPI): Provision of primary frequency regulation from conventional units co-located with battery storage assets ▪ Simpler permitting process: Battery storage systems co-located with renewable plants smaller than 300 MW gain access to a simplified authorization process, as long as they do not require additional land or a change in land usage ▪ Subsidies: Co-located renewables plants are eligible for almost all subsidy schemes, including the current FER1 scheme. ○ With co-location, energy fed into the grid includes the energy absorbed by the battery from the grid and subsequently discharged back in – this energy is excluded from the subsidy calculation

	○ The energy absorbed by the battery from the grid and subsequently discharged back in can be used to gain arbitrage revenues ○ When installing a battery on an existing RES plant, the energy service system operator GSE must be informed within 60 days of commissioning and a fee to cover administration costs must be paid, whether the plant is subsidised or not ○ Subsidised RES assets who do not comply with the GSE information requirement lose access to the subsidy scheme
Spain	▪ Simpler permitting process: Existing facilities setting up a co-location design with renewables or storage (hybrid) are authorised to use the same grid connection without the need to request new access permits (Royal Decrees 1183/2020). ▪ Grid capacity auction: Hybrid (storage plus solar or wind) projects can participate in grid capacity auctions ▪ Batteries are permitted to be hybridised with renewable assets that receive regulatory subsidies (Royal Decree 413/2014), as long as equipment measuring each asset's generation is installed ▪ Plants under the REER regime (Economic Regime for Renewable Energy) may consist of more than one technology, including both new and existing assets – i.e., they are allowed to become a hybrid plant. For existing assets, only the new investments will be remunerated under the REER regime (Royal Decree 960/2020) ▪ Subsidies for innovative co-located projects with renewable sources (Recovery, Transformation and Resilience Plan, PERTE ERHA scheme): ○ Maximum subsidy of 15mn € per project or per company (maximum support over eligible costs of 65% (55%, 45%) for small (medium, large) enterprises) ○ At least 2h duration storage, at least 1 MW of capacity or 1 MWh, at least 40% of hybridisation with the renewable asset(s) capacity, application period January-March 2023
Great Britain	▪ Only support schemes for co-location of storage and PV assets for homeowners encountered (residential use)

Table 13: Overview of support policies for renewable assets co-located with energy storage

5.3 Grid charges for industrial consumers

Just like generators, end consumers of electricity are subject to pay grid charges to compensate grid operators for operating and maintaining the electricity grids. LDES could potentially be applied by C&I electricity consumers to lower their grid charges. Therefore, this chapter provides an overview of the relevant regulation on grid charges for commercial and industrial consumers.

There is no uniform design of grid charges in the EU. The respective NRAs are responsible for establishing a methodology underlying the calculation of network charges in each Member State. Therefore, the respective national regulations must be considered individually to be able to draw conclusions on the potential business models for LDES technologies later.

Transmission grid tariffs vs. distribution grid tariffs

The costs for the use of the electricity grid are determined separately for the transmission grid level and the distribution grid level. This means that large consumers who are directly connected to the high-voltage transmission grid only face a transmission tariff. For consumers connected to the distribution grid level, the grid fee usually consists of a share for the distribution grid as well as a share for the transmission grid (ACER 2023).

Tariff structures

A rough distinction can be made between charges related to the connection of a consumer to the grid (usually a one-off payment) and usage-based grid fees, i.e., costs derived from the use of the network. There are three methods for determining the amount of usage-dependent grid fees:

- Energy (volumetric): A grid charge that is dependent on the amount of electricity consumed by the customer (in €/kWh), i.e., the total consumption over a year.
- Power (capacity): A charge dependent on the peak demand of a customer (in €/kW), i.e., the hour or quarter-hour with the highest amount of electricity drawn from the grid in a year.
- Fixed (lump sum): A fixed amount that does not vary with use.

The three methods are not mutually exclusive. In many countries, a combination of the calculation methods is used to derive the grid fees that apply to a consumer. Drawing on publications of ACER on grid fee methodologies in Europe, Table 14 provides an overview of the network charge structure applying to industrial consumers in the countries under consideration (ACER 2019, 2021, 2023).

Country	Grid fee methodology	Description and variations
Germany	Mix of Energy + Power	▪ Applicable for an annual consumption of above 100 MWh[22] ▪ Reduced network charges apply if the usage profile meets the criteria for an *atypical grid usage* or an *intensive grid usage* ▪ *Atypical grid usage*: Avoidance of load peaks during periods of overall high grid load

[22] Consumers below the threshold of 100 MWh are not subject to power-based charges.

		▪ *Intensive grid usage*: More than 10 GWh consumption and at least 7,000 full consumption hours per year[23]
France	Mix of Energy + Power	▪ 65% Power, 35% Energy ▪ Tariffs depend on voltage levels
Spain	Mix of Energy + Power	▪ Tariffs for industrial customers are largely power based
Italy	Mix of Energy + Power	▪ 10% energy based + 90% power based for industrial consumers on the high voltage level ▪ Consumers on the medium voltage and low voltage level pay on the basis of energy
GB	Energy or Power	▪ Consumers with half-hourly settled meters pay power-based charges determined by their demand in the three half-hours with the highest net system demand between November and February (so-called *triad periods*) ▪ Consumers without half-hourly measurement are subject to an energy-based tariff depending on their annual consumption between 4pm and 7pm

Table 14: Overview of grid fees in selected European countries

Time-of-use network tariffs

Some countries use time-of-use (ToU) network tariffs. These tariffs are structured in a way that the amount charged is not uniform but depends on the time of grid use (e.g., seasonal, monthly, peak/off peak time periods).

The basic idea behind this is to stimulate more efficient grid use. In times of very high grid utilisation, higher grid fees are charged to encourage consumers to reduce their load. In off-peak periods, the grid charges are lower, thus incentivising consumers to increase their demand in these periods. In most cases, ToU network tariffs are static, i.e., they vary according to predefined time periods (e.g., according to a daily profile or an annual profile). Table 15 provides an overview of whether ToU network tariffs are applied and how they are designed in the focus countries of this study.

Country	**Availability of ToU network tariff**	**Design details**
Germany	No	
France	Yes	▪ ToU tariffs for both transmission and distribution grid fees

[23] Full consumption hours are defined as the quotient of the annual consumption and the peak demand.

		▪ Applicable to both the energy-based and the power-based component of the grid fees ▪ Seasonal ToU schedule with November-January defined as peak months ▪ Daily ToU schedule for transmission tariffs with 9:00-11:00 and 18:00-20:00 defined as peak hours ▪ Network users connected to the 330 kV and 400 kV networks are excluded
Spain	Yes	▪ ToU tariffs for both transmission and distribution grid fees ▪ Applicable to both the energy-based and the power-based components of the grid fees ▪ Seasonal ToU schedule with December – February and July defined as peak months for the Spanish mainland ▪ Daily ToU schedule for transmission tariffs with 10:00-14:00 and 18:00-22:00 defined as peak hours
Italy	No	
GB	Yes	▪ TNUoS charges are based on a consumer's demand for electricity during peak periods, typically during winter weekdays between 4 pm and 7 pm ▪ DuoS charges are based on a consumer's demand for electricity during peak periods, which vary depending on the region and the distribution network ▪ Some electricity suppliers in Great Britain offer ToU tariffs to their customers, which reflect the different grid charges during different times of the day

Table 15: Overview of time-of-use network tariffs in selected European countries (Source: ACER 2023)

6. Potential business cases

6.1 Overview of business models

In this chapter, possible applications of LDES are identified and assessed with regard to their business potential. The analysis of the business models includes an assessment of the general market potential for energy storage, as well as an elaboration of advantages and disadvantages compared to lithium-ion (li-ion) batteries with shorter storage durations. In addition, the market attractiveness of LDES in the five focus countries of this study is compared, drawing on the findings from the previous chapters on market design and regulation.

There are different ways to differentiate and cluster business models for energy storage. Categorisations of storage applications have been made according to the segments of the energy system that benefit from a given service (EASE 2020), the grid level at which storage assets are connected (DNV 2016), or the market roles of energy storage users (Baumgarte et al. 2020). Furthermore, the terms *business model*, *use case*, *application*, and *revenue stream*, cannot always be clearly separated, and are sometimes used interchangeably.

The classification used in this study follows the logic of clustering energy storage applications according to the users of energy storage assets. Four clusters are identified and referred to in the following as *business models*. In each of the business models, LDES can be used for multiple *applications*.

1. **Stand-alone grid scale storage**: LDES is used as a stand-alone asset to perform market arbitrage and provide ancillary services. The main users are traders, utilities, and major energy companies.
2. **Co-location with renewables plants**: LDES is applied in conjunction with renewable assets such as wind parks or solar PV installations to optimise generation and save costs. The main users are renewable power producers.
3. **Customer energy management**: LDES is installed behind-the-meter at a C&I energy consumer to reduce electricity costs, increase self-consumption, save emissions, or generate revenues from market participation.
4. **Storage-as-transmission asset**: LDES is used by grid operators as an integral part of the transmission infrastructure to increase the efficiency of the grid usage, avoid congestion, and save on grid expansion costs.

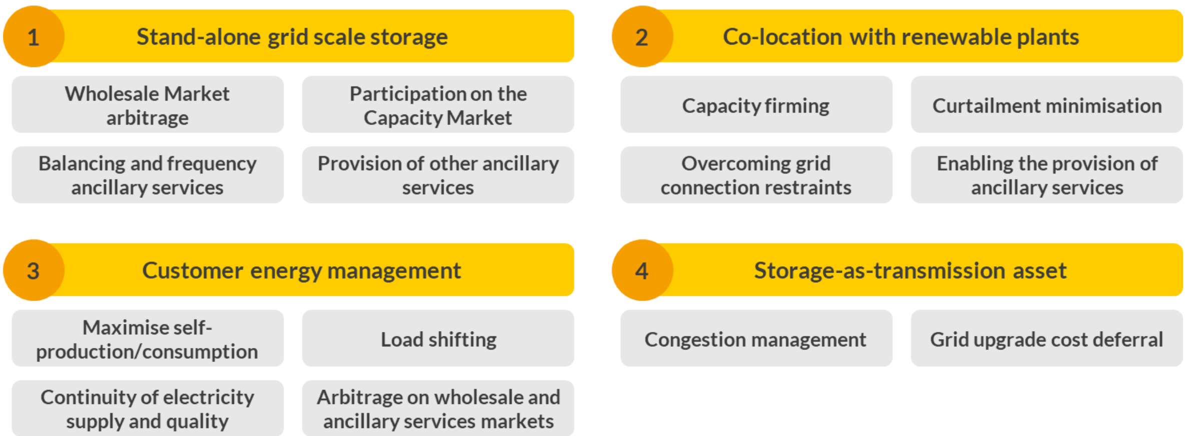

Figure 15: Potential LDES business models (business models in yellow, applications in grey)

6.2 Stand-alone grid scale storage

In this business model, LDES systems would be operated as independent assets with a direct connection to a transmission or distribution grid. Since the operation of the storage system is not constrained by the requirements of another facility (such as a generator or a consumer), the stand-alone business model offers the greatest potential for generating revenues from participating on wholesale electricity markets, capacity markets, and ancillary service markets.

6.2.1 Potential applications

6.2.1.1 Wholesale market arbitrage

Electricity wholesale market arbitrage refers to the practice of buying and selling electricity in the wholesale market with the goal of profiting from differences in electricity prices (also called *price spreads*). In the electricity market, prices fluctuate based on a variety of factors such as supply and demand, weather conditions, fuel costs and the fact that the marginal producer sets the price. Electricity wholesalers who engage in arbitrage take advantage of price spreads by buying electricity when prices are low and selling it when prices are high, earning a profit from the difference between the purchase price and the sale price.

LDES assets can provide a valuable tool for electricity wholesale market arbitrage by enabling the storage and discharge of energy at strategic times to take advantage of volatility in the market. When power prices are low, the LDES asset can be charged using the low-cost electricity. As soon as prices are high, the LDES system discharges the stored energy and reinjects it to the grid (see Figure 16 for an illustration).

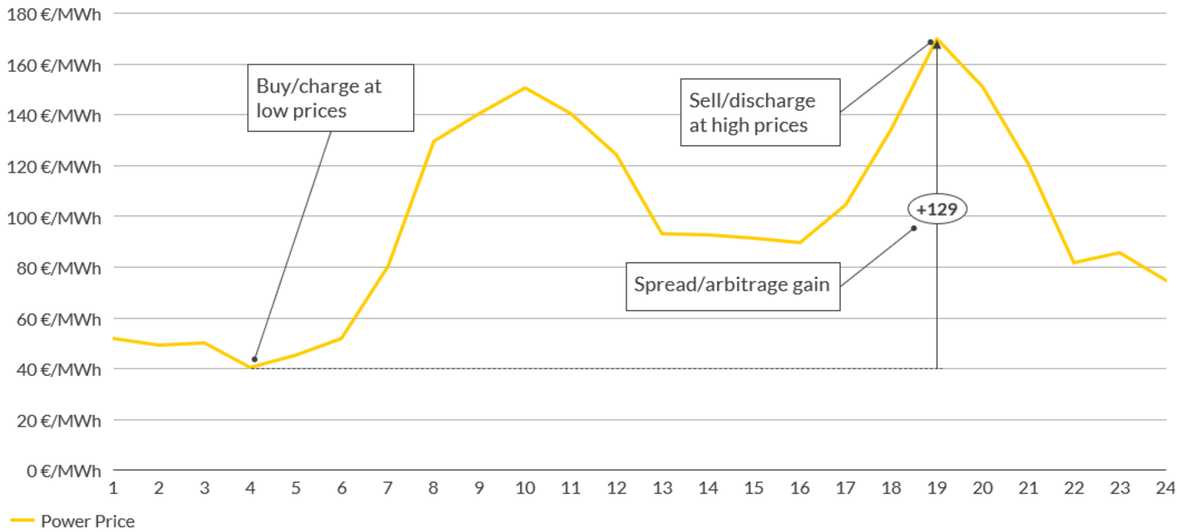

Figure 16: Illustration of a wholesale market arbitrage strategy with storage for an exemplary day

The revenue potential of wholesale market arbitrage depends on the spreads between bottom and top prices. The development of high and low prices in turn is determined by a variety of factors such as prices for commodities used for electricity generation (gas, coal, hydrogen in the future), electricity demand, the buildout of renewable capacity, and the amount of flexibility in the system.

Wholesale market arbitrage does not necessarily require long storage durations. In fact, shorter duration li-ion batteries are already being used for this purpose. LDES has an advantage in situations where prices remain at a high level for multiple hours to days. In this case, an LDES system could discharge over a longer time horizon compared to a short-duration battery and hence capture a higher revenue. Table 16 provides an overview of the key opportunities and risks associated with the revenue stream of wholesale market arbitrage.

Opportunities	Risks
▪ The growing capacity of intermittent renewables, combined with high commodity prices, could lead to high spreads ▪ The longer discharge duration of LDES can be an advantage over short-duration batteries in certain market situations	▪ High exposure to merchant risks and movement of market fundamentals such as commodity prices and economics of renewables ▪ Bottom prices may increase in a net zero world, driven by battery deployment, smart EV charging and hydrogen electrolysis. Top prices may fall if lower gas demand depresses gas prices and thus operating costs for gas-fired power plants

Table 16: Opportunities and risks of using a storage asset for wholesale market arbitrage

In a public report conducted for Breakthrough Energy, Aurora has modelled the large-scale deployment of LDES in Germany and quantified the economic potential of day-ahead market arbitrage for several LDES technology options (Aurora Energy Research 2022). It was found that gross margins from wholesale power market arbitrage will increase by a factor of 3.5 for the LDES systems considered over the next 15 years in Aurora's Net Zero Power Market Scenario due to the strong buildout of renewable generation capacity (see chapter 6.2.3 for a closer consideration of the study results)[24].

The relevant markets for wholesale market arbitrage are the day-ahead and the intraday markets. In all countries evaluated in this study, energy storage assets can participate in these markets.

	Germany	France	Italy	Spain	Great Britain
Access to Day-ahead and Intraday Markets	●	●	●	●	●

Figure 17: Access to day-ahead and intraday markets for wholesale market arbitrage

Another form of arbitrage that LDES technologies with very long discharge times and high energy storage capacities could be used for is seasonal arbitrage. This type of arbitrage takes advantage of seasonal variations in electricity demand, generation, and prices. For example, in regions with a high share of renewable energy generation, electricity generation can vary significantly between seasons. During the summer months, when there is abundant sunlight and wind, renewable energy generation can exceed demand, resulting in lower prices. Conversely, during the winter months, when there is less sunlight and wind, renewable energy generation can fall short of demand, resulting in higher prices. Seasonal storage can help to smooth out seasonal variations in the power market, improving the overall efficiency and stability of the electricity system.

[24] In the Net Zero Scenario, it is assumed that the national decarbonisation targets are achieved.

Due to the availability of conventional dispatchable power plants, seasonal storage does not yet play a major role in the electricity sector[25]. Its importance will likely increase, however, considering the transformation of the energy supply towards intermittent renewable energy sources and decarbonisation targets (Petkov and Gabrieli 2021, EPRI 2022). However, it is questionable whether seasonal storage alone can generate enough revenue to provide a return that would stimulate private investment (EPRI 2022). See Table 17 for a comparison of the risks and opportunities related to seasonal electricity storage.

Opportunities	Risks
▪ As the share of renewables in the system increases, seasonal variations in electricity prices will likely become larger (low-cost solar and wind generation will be able to generate sufficient electricity in the summer to cover demand in most hours, which means that prices will be at a low level on average. In winter, gas (or in the future hydrogen) power plants with higher operational costs will still be required, which means that power prices are higher on average. ▪ There is no competition from short-duration li-ion batteries in this trading strategy.	▪ Compared to arbitrage on the day-ahead and intraday markets where energy storage assets are cycled (charged and discharged) on a continuous basis to generate revenues, seasonal arbitrage only utilises the storage asset for one cycle and only generates a single revenue stream. Hence, the seasonal spread must be very significant to make up for storage costs and outperform an arbitrage strategy based on short-term volatility on the spot market. ▪ Seasonal variations in electricity prices are less predictable than volatility on the day-ahead market because prices are influenced by a range of factors, including weather patterns, fuel prices, and demand patterns, which can be difficult to forecast accurately over long time periods. This can increase the risk of investing in a seasonal arbitrage project. ▪ Due to the large storage capacity dimensions required for seasonal arbitrage, capital expenditure and cost of capital for seasonal storage projects is likely to be significantly higher than for a LDES project with a shorter storage duration.

Table 17: Opportunities and risks of using a storage asset for seasonal arbitrage

[25] There are already some projects for the seasonal storage of heat, however. Two such projects have been announced in Finland last year (cf. Helen 2022, PV Magazine 2022)

6.2.1.2 Participation on capacity markets

On capacity markets, electricity providers are remunerated for their commitment to have a certain amount of capacity available during a specified period. Participation in capacity markets can be attractive for LDES because, unlike arbitrage on day-ahead and intraday markets, capacity market contracts provide a stable and predictable source of revenue. Depending on the specific national designs, revenues can be secured for a time horizon of up to 15 years (Great Britain and Italy). Even if Capacity market payments do not provide the main source of revenues, the stable income flow can improve project financing conditions. On the other hand, locking in a price for a capacity contract for a long duration entails the risk of forgoing potentially higher revenues on other (short-term) markets.

De-rating factors applied to energy storage assets for their participation in capacity markets are determined based on the maximum discharge duration at full capacity. Therefore, LDES assets generally achieve higher de-rating factors than short-duration batteries and can achieve a higher remuneration per unit of installed capacity.

Opportunities	Risks
▪ The retirements of conventional capacity (coal, nuclear in some countries) increases the demand for capacity from other technologies such as energy storage. This could mean that higher prices can be achieved in the future. ▪ Since providing power for long durations supports security of supply, LDES assets can receive relatively high de-rating factors.	▪ While a multi-year capacity contract provides revenue certainty, year-on-year volatility of auction outcomes could cause the contract to be locked-in based on a relatively low clearing price. ▪ Long lead times for some LDES projects can be problematic for securing a capacity contract because usually, the capacity needs to be delivered a few years after contract award.

Table 18: Opportunities and risks of participating in capacity markets

As described in chapter 4 of this report, not all countries have a capacity market in place and the design of the respective markets varies. Figure 18 provides an assessment of the capacity market access conditions in the countries evaluated in this study.

Country	Market access rating	Reasoning
Germany	🔴	▪ There is no capacity market in Germany ▪ The debate around the introduction of a capacity market has picked up recently, but still too early to make any predictions
France	🟢	▪ LDES can participate in the French capacity market auctions ▪ Auctions take place 4 years ahead of delivery time ▪ With 1 year, the delivery period is short compared to other countries
Italy	🟢	▪ LDES can participate in the Italian Capacity Market auctions ▪ Auctions take place 4 and 3 years ahead of delivery time ▪ The contract length for new-built assets is 15 years
Spain	🟡	▪ Currently, there is no capacity market in Spain ▪ A capacity market was announced in 2021 and is currently under review by the European Commission ▪ LDES would be able to participate and secure a 5-year contract (for new-built assets)
Great Britain	🟢	▪ LDES can participate in the British capacity market auctions ▪ Auctions take place 4 years ahead of delivery time ▪ The contract length for new-built assets is 15 years

Figure 18: Assessment of the capacity market access conditions for LDES

6.2.1.3 Provision of balancing and frequency services

LDES can play a role in providing balancing and frequency services due to their ability to balance the load on the grid in both directions (i.e., absorbing power when the frequency is too high and discharging when the frequency is too low). See chapter 3.5.1 for an explanation of balancing and frequency services and their role for the power system.

To participate in balancing and frequency services markets, LDES systems must meet the technical requirements specified by the respective NRAs and TSOs[26]. These requirements include minimum response times, ramp rates, and availability criteria (see chapters 3 and 4 for details). Some frequency response services require very fast ramp rates that not all LDES technologies can meet. Compared to li-ion batteries which generally have fast activation times but shorter storage durations, LDES might be more suited for balancing services and frequency services that allow for longer minimum response times but require longer minimum activation times (and hence a longer storage duration).

Opportunities	Risks
▪ Energy (supply/demand) balancing needs are expected to increase in the future with the growing capacity of intermittent renewables, leading to higher prices for balancing services.	▪ High exposure to merchant risk and movement of market fundamentals. ▪ Market saturation risk: The build-out of other flexible technologies such as short-duration assets could depress prices and erode margins. The saturation risk on balancing and frequency services markets is higher than on the wholesale market because the volume traded is much smaller. Therefore, an increase of supply in the range of several hundred MW can already have a significant impact on prices and revenues.

Table 19: Opportunities and risks for balancing and frequency ancillary services markets

As described in the first two chapters, the procurement mechanisms for balancing and frequency services and their design are not (yet) harmonised throughout Europe. Figure 19 summarises the market access situation for LDES in the countries evaluated in this study[27].

[26] In Germany, TSOs publish the prequalification requirements for the FCR, aFRR, and mFRR markets on the online platform for the procurement of frequency ancillary services *Regelleistung.net*: https://www.regelleistung.net/ext/static/prequalification.

[27] Balancing services includes the balancing mechanism in Great Britain and frequency products with a full activation time of 10 minutes or more in the other countries (such as mFRR, RR, and Secondary/Tertiary Reserves within Italy's MSD). Frequency services refers to products with a full activation time below 10 minutes, such as FCR and aFRR. See Figure 6 in chapter A.3.5 for a full overview.

Country	Balancing Services (BS)	Frequency Services (FS)	Reasoning
Germany			▪ LDES can participate in the FCR, aFRR, and mFRR markets
France			▪ FS: LDES can provide FCR but currently not aFRR. aFRR and energy and capacity markets will be opened in 2023 and 2024, respectively. ▪ BS: LDES can participate on the mFRR and RR markets
Italy			▪ The MSD is currently only open to dispatchable production units with installed power over 10 MW ▪ The UVAM pilot scheme allows aggregated units to participate in the MSD ▪ A reform which would open the MSD to energy storage assets is expected for 2023
Spain			▪ BS: LDES can participate on the Tertiary Reserve and Replacement Reserve markets ▪ FS: The Primary Reserve is a mandatory, non-remunerated service but LDES can participate in the Secondary Reserve
Great Britain			▪ LDES can participate on the Balancing Market and various frequency ancillary services markets

Figure 19: Assessment of the market access to balancing and frequency ancillary services for LDES

6.2.1.4 Provision of other ancillary services

A stand-alone LDES system could also be applied to offer other ancillary services such as black start, voltage support, and congestion management. Unlike for balancing and frequency ancillary services where auction-based procurement is already the norm, the procurement of non-frequency ancillary services is less market based. While tenders are in place or emerging in some countries, many system operators apply other schemes for the procurement of non-frequency ancillary services that range from negotiated contracts to regulated prices to non-remunerated service obligations. In some countries, energy storage facilities are not eligible to provide certain non-frequency ancillary services.

Country	Access rating	Reasoning
Germany		▪ TSOs procure non-frequency ancillary services either via bilateral contracts or the provision is mandatory for generators ▪ The NRA BNetzA has recently decided that TSOs should introduce a market-based procurement mechanism for the system restoration (black start) service ▪ Some pilot schemes for local flexibility markets have been launched
France		▪ Energy storage assets are not allowed to provide voltage control to the TSO ▪ There is no black start service in France ▪ The TSO RTE and the largest DSO ENEDIS have launched calls for local flexibility tenders in dedicated areas
Italy		▪ Services are not marketed nor remunerated and made compulsory for all eligible generation units
Spain		▪ Currently, energy storage facilities cannot provide non-frequency ancillary services in Spain. ▪ A reform is planned to let energy storage facilities participate in the Technical Restrictions market, which would enable them to provide certain non-frequency ancillary services
Great Britain		▪ The TSO National Grid has launched a series of tenders for voltage control, congestion management, and system restoration services ▪ On the DSO level, there are six local flexibility tenders available with four standardised products each

Figure 20: Assessment of the market access to other ancillary services for LDES

Opportunities	Risks
▪ Currently, non-frequency ancillary services are often provided by conventional generators such as gas turbine power plants. With ongoing decarbonisation efforts and the retirement of fossil generators, grid operators will have to find other sources to maintain grid stability. ▪ There is a trend for more countries to move to market-based procurement mechanisms for non-frequency ancillary services.	▪ Currently, market-based procurement of non-frequency ancillary services is not the norm in most of Europe and it is not certain that countries will move towards implementing tender mechanisms such as in Spain or Great Britain. ▪ Revenues from some non-frequency ancillary services are highly dependent on location due to the grid conditions and configuration. Requirements for services such as congestion management and voltage control change over time, subject to TSO's grid reinforcement plans.

Table 20: Opportunities and risks of the provision of other ancillary services

6.2.2 Combination of applications

Combining multiple applications (revenue stacking) can help energy storage asset owners to maximise profits and reduce their payback period, making the investment in a stand-alone LDES facility more attractive and financially viable. Therefore, it is important to consider if applications can be easily combined or rather mutually exclude each other. Table 21 provides an indicative assessment of the feasibility of various revenue stacking options.

A revenue stacking strategy that is attractive and already pursued by energy storage operators is the combination of wholesale market arbitrage with the provision of balancing and frequency services. In countries where markets for balancing and frequency services are available to energy storage, the optimisation of storage charging and dispatch cycles across both wholesale and frequency services markets can be seen as an enhanced arbitrage strategy. For instance, a trader might procure electricity on the day-ahead market to charge the storage facility when prices are low and then decide to use the stored energy to bid into a frequency services market if prices there offer a higher return than available spreads on the day-ahead market.

Participation on capacity markets can generally also be combined with wholesale market arbitrage and the provision of balancing and frequency services. However, in some cases, participation in a capacity market can limit an energy storage asset's ability to participate in other markets. For example, if an energy storage asset has committed to providing capacity to the grid during a certain period, it may not be able to engage in wholesale market arbitrage during that same period. Similarly, if the asset is dispatched to provide frequency regulation services, it may not be able to deliver the contracted capacity in the capacity market.

Combining the provision of non-frequency ancillary services with other applications can also be feasible. However, some non-frequency ancillary services might require the storage asset to be operated in a way that limits the ability to perform other applications. For example, the provision of black start services requires the energy storage asset to maintain a certain state of charge and be ready to provide power at any time, which could limit its availability for other revenue-generating activities such as wholesale market arbitrage.

	Wholesale market arbitrage	Capacity market participation	Balancing & frequency services	Other ancillary services
Wholesale market arbitrage				
Capacity market participation				
Balancing & frequency services				
Other ancillary services				

Table 21: Indicative assessment of application combinations for standalone storage systems[28]

It is important to underline that the above analysis is to be understood as a general overview based on theoretical feasibility and observed market activity. The specific profit maximising revenue stacking strategy may vary depending on the regulatory framework, market design, and available market opportunities in the specific location of the asset (see chapter 4 for details). Besides, even when energy storage is eligible to participate in multiple markets, this might only be possible if specific conditions are fulfilled. For example, the eligibility criteria for participating in a capacity market usually differ from those for participating in ancillary services markets (see chapter 4 for details). Additionally, energy storage assets may be required to register with different entities depending on the market in which they are participating.

6.2.3 Attractiveness of the business model

In this chapter, the attractiveness of the stand-alone LDES business case is evaluated based on previous quantitative work conducted by Aurora, insights form a market survey on energy storage in Europe, and a qualitative assessment of the LDES project pipeline.

Detailed modelling of future revenue streams from the energy storage applications described above for each of the five focus countries is not within the scope of this study. However, Aurora has recently modelled the buildout of LDES in the German power sector (Aurora Energy Research 2022)[29]. Part of the analysis focused on forecasting wholesale market revenue potentials for multiple LDES technologies. The modelling showed that without government support, LDES projects would become investible between 2030 and 2035. Until 2030, wholesale market revenues generated over the asset's lifetime are not yet sufficient to cover the capital expenditure and fixed costs for any of the LDES technologies considered. See Figure 21 for an overview of the results of the profitability analysis[30].

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[28] Combinations of applications that can be easily combined and are already observed in the market are coloured green. Yellow means that a combination is possible but entails certain limitations or restrictions. Red would mean that applications are not compatible.

[29] Similar work is currently being conducted by Aurora for the Spanish market.

[30]Note that in deviation from this study, LDES was defined as storage assets with a storage duration between 8 hours and 96 hours in the 2022 report. Therefore, systems with storage durations lower than 10 hours (8-hour li-ion and 8-hour vanadium flow batteries) were considered in the profitability assessment.

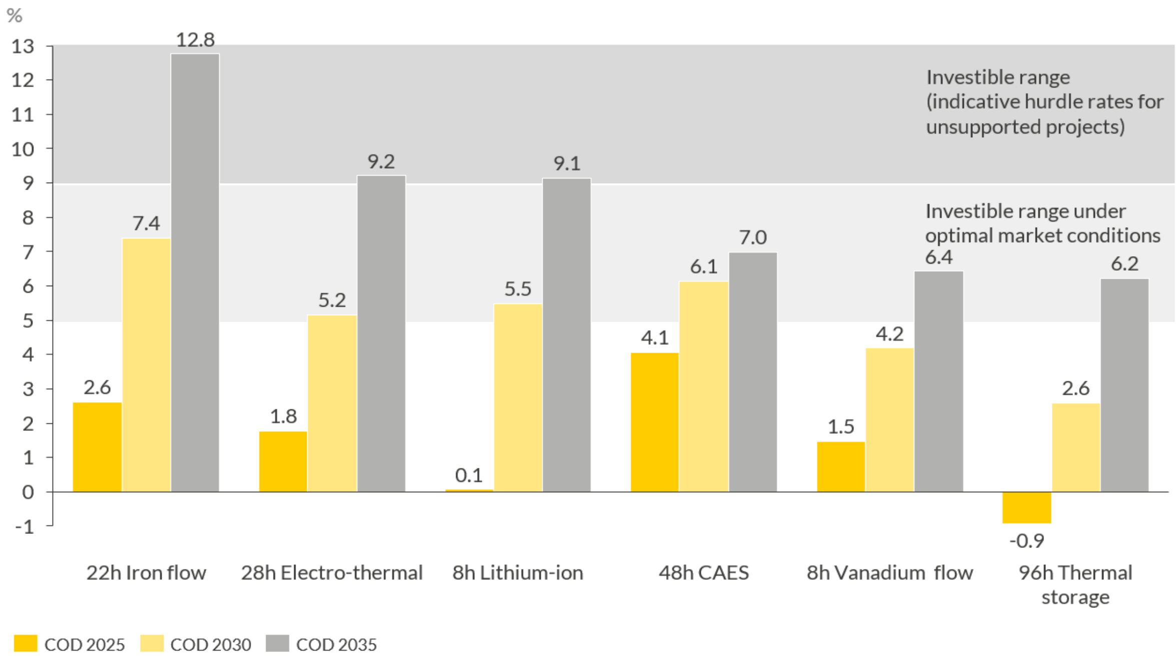

Figure 21: Internal rate of returns forecast for six selected LDES technologies and three commercial operation dates (COD) in Germany

As the quantitative results from the 2022 study only refer to the application of wholesale arbitrage and only partially cover the geographical focus of this report, further sources are considered in the following to provide a more comprehensive assessment of the attractiveness of the stand-alone LDES business model.

The research consortium EnTEC has recently published a study on energy storage in Europe that contains a survey on the type of storage services provided and the revenue shares generated with these services (EnTEC 2023). The survey was conducted among members of the European Association for Storage of Energy (EASE) and had 93 respondents. Li-ion batteries are the most represented technology within the respondents' products, projects, or portfolios. However, a wide range of other technologies that are capable of providing long-duration storage are also represented (e.g. hydrogen storage, thermal storage, flow batteries, compressed air energy storage (CAES), liquid air energy storage (LAES), latent heat). Concerning the geographical distribution, Germany, Spain, France, and the UK are within the top five represented locations of the respondent's projects or portfolios[31].

The survey is built on the EASE classification of energy storage services, which classifies the services in five clusters (EASE 2020):

- Generation Support Services and Bulk Storage Services
- Services to Support Behind-the-meter Customer Energy Management
- Ancillary services
- Services to Support Transmission Infrastructure

[31] Germany: 38%, Spain: 19%, France: 17%, UK: 16%, Italy: 10%.

- Services to Support Distribution Infrastructure

Although this categorisation differs from the definition of LDES business models used in this study, it is similar enough to allow a transfer of the results.

According to the survey results, wholesale market arbitrage and ancillary services are among the most provided services by energy storage facilities in Europe. 63% of respondents stated that their energy storage technologies or projects provide Generation Support Services and Bulk Storage Services. Within this service cluster, wholesale market arbitrage is the most widespread activity (73%). Approximately half of the total respondent's technologies or projects are designed to provide ancillary services which makes it the second most popular service cluster. Within this cluster, balancing and frequency services are the ones that are provided the most (79% FCR, 67% aFRR). Of the Other ancillary services, voltage support is the most widespread (54%).

With regards to revenues generated, Generation Support Services and Bulk Storage Services and ancillary services are leading as well with an average revenue share of 35%, respectively, among all respondents.

Since the stand-alone operation of an LDES facility is well suited to engage in wholesale market arbitrage and to provide ancillary services, the survey results could indicate that this business model is particularly attractive. Indeed, a recent study commissioned by EASE predicts a strong growth for front-of-meter energy storage installations in the countries considered in this report (Delta Energy & Environment, 2022). However, as stated previously, it is important to keep in mind that many of the revenue streams can also be captured with short-duration storage systems such as li-ion batteries which are already mature and generally have lower capital costs. When considering implementing the stand-alone business model for LDES, it will therefore be paramount to focus on services and markets that reward specific properties of LDES such as the higher storage depth (and on countries that offer specific financial support mechanisms for LDES, see next chapter 6.2.4). Table 22 provides an overview based on the revenue streams discussed in this chapter.

Revenue stream	**Comparison to short-duration batteries**	**Reasoning**
Wholesale market arbitrage	Slight advantage	▪ The longer storage duration of LDES can be used to capture long, sustained high price periods. Some technologies could even allow for seasonal storage. ▪ LDES technologies are typically much less affected by degradation than li-ion batteries. In markets with high volatility, an LDES system might hence be favourable because multiple price spreads per day can be captured without facing the trade-off of reducing effective storage capacity
Capacity markets	Advantage	▪ The de-rating factors applied to storage technologies generally reward longer storage durations, meaning that a higher share of the asset's capacity can be remunerated
Balancing and ancillary services	Slight disadvantage	▪ Some frequency services require very fast ramping rates that are difficult to achieve by many known LDES technologies

Other ancillary services	Balanced	▪ Some LDES technologies are more suited to providing voltage control and black start services compared to li-ion batteries ▪ Local congestion management services can require fast ramping times which favours li-ion batteries

Table 22: Comparison of LDES with li-ion batteries upon their suitability for selected applications

Based on insights from Aurora's country experts in Germany, France, Italy, Spain, and the UK, Figure 22 provides an overview of the market maturity of the stand-alone LDES business model in the countries evaluated in this study[32]. It is important to note that this assessment is based on a limited number of information sources and as such is not to be interpreted as the result of an extensive market research exercise.

There are also several stand-alone LDES projects under development in other countries and regions, among which the following:

- In the Netherlands, LDES developer Corre Energy has recently announced the deployment of a 320 MW CAES system with a storage duration of up to 86 hours for the Dutch utility Eneco. The facility will be used for both daily arbitrage and to capture 2–5-day weather cycles (Energy Storage News 2022f).
- In California (USA), energy storage company Hydrostor develops a 500 MW/4,000 MWh adiabatic CAES facility (Hydrostor 2023)[33]. Recently, Hydrostor has secured an offtake agreement valued at nearly 1 bn $ for 200 MW / 1600 MWh of the storage capacity (PV Magazine 2023). The company develops similar projects in other parts of the USA and Canada.
- In New Brunswick (Canada), the utility NB Power has commissioned pumped heat energy storage developer Malta Inc. to develop a 1,000-MWh stand-alone LDES facility. The facility is expected to commence operation in 2024 (S&P Global 2022).

[32] Note that the assessment focusses on new LDES technologies and projects. In Huntdorf, Germany, a compressed air energy storage (CAES) facility exists since 1978.

[33] Note that the storage duration of the project is indicated with 8 hours and therefore slightly below the 10 hours minimum storage duration defined in this study.

	Market maturity rating	Reasoning
Germany	◑	▪ Aurora Energy Research was involved in the valuation of multiple CAES projects in Q4 2022, final investment decisions are expected for Q2 2023
France	○	▪ No knowledge of announced projects for this business model
Italy	◑	▪ LDES manufacturing company Energy Dome has successfully launched a demonstrator for its utility-scale CO2 storage technology in 2022 (Energy Dome 2022) ▪ The first full-scale commercial project for a 10h storage system (20MW/200MWh) is expected for Q4 2023 (Energy Dome 2022)
Spain	◑	▪ Malta Iberia's LDES system was selected by the EU Innovation Fund to deploy a 100 MWh thermal energy storage system with 10h duration (Malta Inc. 2022) ▪ Interest in the market as evidenced by a study currently conducted by Aurora for Breakthrough Energy
Great Britain	◑	▪ Several projects of interest, including for LAES, CAES, gravity storage, vanadium flow, although none have reached development phase yet ▪ Highview Power has announced to build a 30MW/300MWh liquid air energy storage (LAES) facility near Manchester (FT 2022)

○ Very limited market interest ◔ Some interest ◑ Project(s) announced / under development ◕ Project(s) finalised ● Mature market

Figure 22: Assessment of market maturity for the stand-alone LDES business model

6.2.4 Regulatory best practices in the evaluated countries

Aside from the question of market availability and market access, other policy and regulatory aspects are relevant to evaluate whether the business model of operating a stand-alone LDES asset is attractive in a certain country. Drawing on the detailed regulatory analysis from chapter 3 of the study, Table 23 provides an overview.

Best practices	**Countries in which best practices are fulfilled**
Grid fee and/or tax regimes that avoid double-charging for storage assets	Germany, Italy, Spain, Great Britain
Clear rules for the combination of revenue streams from multiple markets (revenue stacking)	Great Britain
Formulation of energy storage strategy, including specific deployment targets	Italy, Spain, Great Britain
Specific deployment targets for LDES	Italy
General financial support policies for stand-alone energy storage assets	Italy, France, Spain
Specific financial support policies for the deployment of LDES	Italy, Great Britain (announced)

Table 23: Regulatory best practices for stand-alone LDES

6.3 Co-location with renewable energy plants

Co-location refers to installing a storage plant next to one or several renewable generators, usually solar PV or onshore wind. Hereby, the combination of the storage and renewable assets is also known as a "hybrid" plant. In this business model, the LDES and renewable assets share a grid connection point and are considered as one hybrid generator combination. The LDES storage is subject to requirements from the renewable generator.

Generally, there are two broad co-location set-ups: AC (alternating current) or DC (direct current). For an AC-coupled co-located plant, the renewable asset and the storage each have a separate inverter, while for a DC-coupled co-located plant, they share the same inverter. If the storage facility can only charge from the renewable asset, such as in a DC-coupled set-up, it cannot provide services that require a certain state of charge (e.g., the FCR market accepts only symmetric bids). This is detailed in chapter 6.3.1.4.

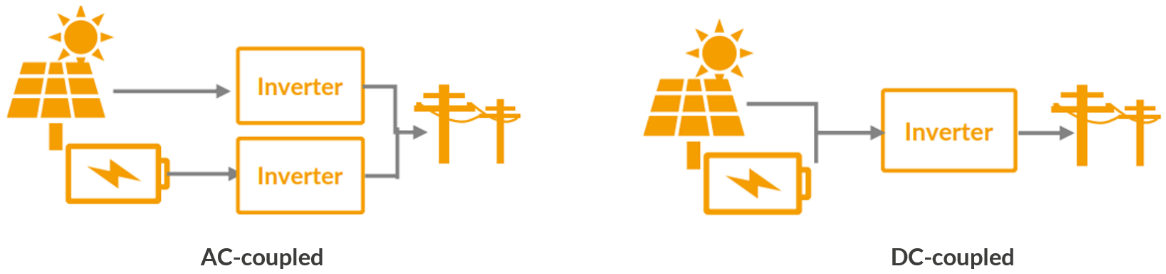

Figure 23: Schematic overview of an AC-coupled vs. a DC-coupled set-up for co-location

The applications described in chapter 6.2 for the stand-alone LDES business model are potentially also accessible for co-located assets (such as participation in a capacity market) but could be subject to specific regulatory requirements or might not yet be clearly defined from a regulatory standpoint. Further information on policies and regulations can be found in chapter 4.

	Germany	France	Italy	Spain	Great Britain
Co-location of RES and storage allowed	●	●	●	●	●

Figure 24: Overview of countries where co-location of a renewable and storage asset is possible

6.3.1 Potential applications

6.3.1.1 Capacity firming

Capacity firming refers to the "use of energy storage to render variable renewable output more constant during a given period of time" (EASE 2020). Hereby, the storage asset is used to store renewable production during peak production hours. The stored electricity is then discharged as supplement generation whenever the renewable generator is intermitting its production.

In the future, this use case could gain more relevance as it is possible that the requirements for a net-zero definition for renewable purchases become stricter (e.g., for green hydrogen, temporal correlation must be given on an hourly basis after 2030, see chapter 4.1.2 for further details). Capacity firming via co-located storage assets, e.g., firming for renewable PPAs, would make it possible for companies to match their energy with local renewable supply generated at the same time, committing to 24-7 renewable energy. This would require a tailored sizing of both the renewable plant and the storage asset.

Opportunities	Risks
▪ PPAs by corporates/utilities might provide a premium for firmed renewable electricity ▪ Could enhance options for renewable generators to participate in spot markets (arbitrage) and also ancillary services markets ▪ Could profit from renewable support mechanisms specifically targeted at co-location plants (hybrid plants) ▪ Hybrid plants might be specifically considered in capacity markets, as they are able to provide more firm energy (EnTEC 2023)	▪ The PPA market for co-located renewable and storage assets in Europe is still in its infancy ▪ Only few renewable support mechanisms in Europe specifically dedicated to hybrid plants (e.g. innovation auctions in Germany), while some countries may have rules in place, but they are not necessarily supportive (e.g. higher exposure to the market price for hybrid plants in Spain) ▪ Often, hybrid plants are not allowed to withdraw power from the grid, which prevents value stacking ▪ Limited information for capacity mechanism remuneration available for hybrid plants (e.g., Italy has specific rules) (EnTEC 2023) ▪ Tailored sizing of generation and storage assets necessary

Table 24: Opportunities and risks of capacity firming for LDES

An exemplary shift of solar PV generation via a storage asset is depicted in Figure 25, as could be resulting for the use case *capacity firming*. It must be noted that this graph only shows a renewable generation shift for a few hours and not a full 24-hour renewable availability. A similar graph would result for the use cases *curtailment minimisation* and *overcoming grid connection restraints*.

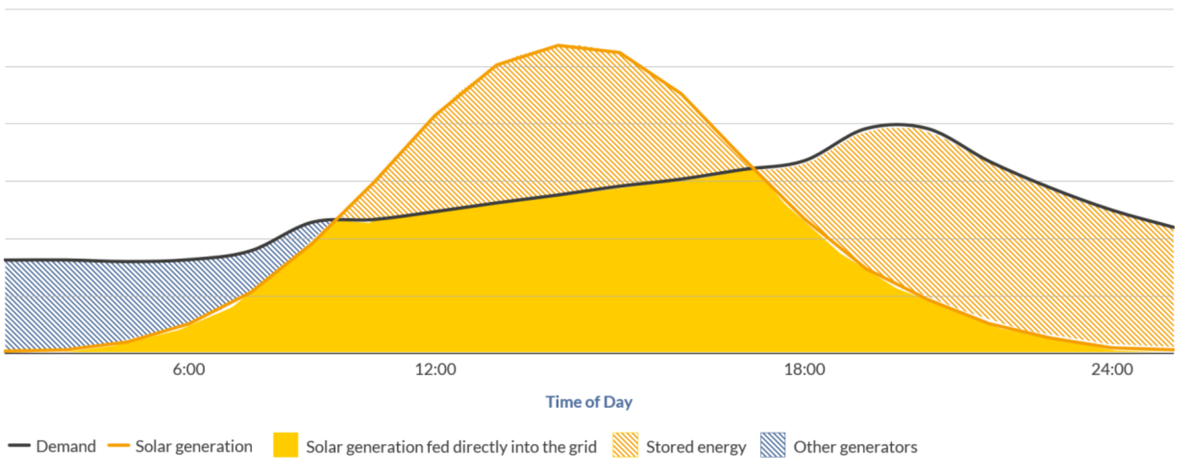

Figure 25: Exemplary solar generation shifting with a storage facility

6.3.1.2 Curtailment minimisation

An alternative motivation to building a co-located renewable and storage plant is to reduce the curtailment that the renewable plant is subject to.

Curtailment is the process of limiting the generation of a (usually renewable) asset at a given time due to power system constraints. The two types of curtailment are economic and technical curtailment. Economic curtailment occurs when renewable generation is reduced due to economic factors or market conditions such as low energy demand, low prices, or lack of market access. This type of curtailment is therefore based on economic considerations. On the other hand, technical curtailment refers to the situation where renewable generation must be limited due to technical constraints such as grid stability, transmission capacity, or system frequency. In those cases, renewable generators must curtail their energy output to avoid overloading the grid or causing technical problems. Grid-based curtailment is usually compensated in the EU.

As an example for economic curtailment, solar plants typically reach their peak generation output around noon. Yet, if there are many solar plants in the area, the combined solar generation may lead to an oversupply of electricity and could surpass the total demand in the grid, which leads to negative power prices for this timeframe. To avoid these negative prices, the solar plants might choose to reduce (curtail) their generation. The same effect can occur for other renewable generators such as wind assets. Especially in stormy weather, both onshore and offshore wind turbines could generate much more electricity than demand is available and therefore the wind generation could be curtailed.

By adding storage assets to a renewable plant, the generated electricity of the hybrid plant can be more evenly distributed over time and the risk of it surpassing demand at a given time is reduced. Thus, curtailment can be reduced or even avoided.

For a renewable operator considering co-location with a storage asset, this effect is attractive as it allows the renewable plant to feed a higher share of its generated electricity into the grid. Also, from a net-zero perspective, it is favourable to avoid curtailment of renewables, as otherwise not the full possible amount of low-cost and low-emission electricity is being used.

Opportunities	Risks
▪ Increased revenues: Curtailment of renewable generation can be avoided ▪ System benefits: Grid stability can be improved by reducing curtailment ▪ Sustainability benefits: Low-carbon electricity used to a larger amount	▪ Technical risk: Sizing of the renewable generator and storage asset need to be aligned ▪ Economic risk: Lost revenues from curtailment need to be sufficient to justify increased costs through storage

Table 25: Opportunities and risks of curtailment minimisation via LDES

6.3.1.3 Overcoming grid connection constraints

An application for a renewable and storage co-located plant, which is similar to the curtailment reduction application, is to overcome grid connection restraints at the plant's site.

Occasionally, the grid connection at the location of a renewable generation asset might not be sufficient for consumption of the total renewable generation of the plant. In such cases, either a build-out of the local grid would be necessary, which is costly and time-consuming, or the renewable plant would need to be downsized, causing inefficiencies and lost potential revenues.

In such cases, the co-location of a storage asset next to the renewable asset can be advantageous. Excess generation which at the time cannot be fed into the grid due to the insufficient grid capacity is instead stored and then fed into the grid when the renewable asset has a lower output, so that free grid capacity has become available again.

The grid connection application is very similar to the curtailment application described in the previous chapter 6.3.1.2. In both cases, the generation time window of the renewable asset is artificially prolonged via the storage asset in order to reduce the total generation output fed into the grid at peak times.

Opportunities	Risks
▪ Build out of renewable assets in locations possible that would otherwise not be available due to grid connection restraints	▪ Technical and economic risk: Sizing of the renewable generator, storage asset, and grid connection capacity need to be aligned

Table 26: Opportunities and risks of overcoming grid constraints via LDES

6.3.1.4 Enabling the provision of ancillary services

Finally, a storage unit combined with a renewable plant could be used to allow the hybrid plant to provide ancillary services by providing some reserve power.

In this application, the storage facility would be used to help the variable renewable generation asset provide ancillary services by keeping a certain level of reserve power (EASE 2020). Hence, it could not fully discharge until the end of the timeframe specified in the bid. Moreover, it has to be noted that some ancillary markets such as the FCR market only accept symmetric bids, relating to both charge and discharge. By participating in these markets, a storage asset could neither fully charge nor fully discharge, always keeping a reserve level available. Only AC-coupled plants can participate in the symmetric FCR market, as only in this set-up a storage can charge from the grid and therefore guarantee its state of charge. In a DC-coupled set-up, the storage can only charge from the renewable asset and is therefore dependent on the renewable asset's generation, not being able to guarantee its state of charge.

As described in more detail in chapter 6.2.1.3 for the stand-alone business case and in chapter 6.3.1.4 for the C&I consumer business case, the provision of ancillary services underlies certain regulatory requirements. Moreover, if the storage asset is rather small, it might be beneficial to not participate as a sole hybrid (co-location of renewable asset and storage) plant in the markets, as this could lead to significant overhead, but instead join an aggregator (virtual power plant, see chapter 6.3.1.4) who can manage the market participation.

Opportunities	Risks
▪ Unlock further revenue streams for hybrid plants, additional to spot market participation ▪ Option considerable to join aggregator (virtual power plant) to reduce administrative efforts	▪ The regulatory framework has not yet been detailed for all countries regarding the market participation of hybrid plants (see chapter 5.2)

Table 27: Opportunities and risks of enabling ancillary services for co-located plants via LDES

6.3.2 Combination of applications

In Table 28, an indicative assessment is provided how well the different applications of a co-location business model can be combined with each other.

The applications *capacity firming*, *curtailment minimisation* and *overcoming grid connection constraints* can be combined relatively well, as they are closely related. All these applications require that not all generated energy is fed into the grid at the same time, but instead a significant amount of generation is stored and only fed back gradually into the grid, smoothening the total grid infeed line significantly.

Therefore, the common objective to synchronise intermittent generation to demand via infeed steering can be achieved in similar ways, serving several applications at once. While each application presents a different motivation to smoothen the power infeed into the grid, several motivations can be relevant at once for the same co-located storage and renewable plant (hybrid plant).

The application of *enabling a renewable plant to provide ancillary services* can be less well combined with the other use cases. In order to provide the necessary power when it is requested (for the given time frame for which the plant operator has placed bids), the storage asset needs to have enough stored energy (or back-up time) available, which implies that it has to be kept charged up until a certain minimum level at these times. The same goes in the reverse direction. If the ancillary service market should request the hybrid plant to consume power from the grid, the storage asset cannot be charged fully but must keep under a certain maximum storage level for these times. While there is a lot of research going into this application (e.g., around the determination of suitable algorithms), it is still not as straightforward as the other applications. It is possible to combine it with the other applications, but this requires careful planning and a detailed knowledge of expected supply and demand deviations.

	Capacity firming	*Curtailment minimisation*	*Grid connection constraints*	*Ancillary services*
Capacity firming				
Curtailment minimisation				
Grid connection constraints				
Ancillary services				

Table 28: Indicative assessment of application combinations for co-location with renewables[34]

6.3.3 Attractiveness of the business model

The EnTEC energy storage revenue stream survey, initially introduced in chapter 6.3.2, provides insights into the potential co-location revenue streams highlighted in this chapter. The stand-alone and co-location business models are not separated in the study, but joined together in a cluster which is stated to be served by 63% of respondents of the survey. Within this cluster, services that can be assigned to the revenue stream *renewable curtailment minimisation* are the most widespread with 53% of cluster respondents generating revenue from this application. The application *overcoming grid connection constraints* is not explicitly stated, but closely related to the *curtailment* application and can therefore be assumed to be similarly popular. This is followed by the application *ancillary services renewable support* with 47%, and concluded by the application *capacity firming*, stated by 40% of cluster respondents (EnTEC 2023). In summary, none of the introduced applications are niche use cases for storage, but rather popular.

As with the other business models, LDES systems are competing with short-duration batteries for market shares in the co-location business model as well.

[34] Combinations of applications that can be easily combined are coloured green. Yellow means that a combination is possible but entails certain limitations or restrictions. Red would mean that applications are not compatible.

Concerning the application *capacity firming*, existing examples mostly focus on the use of short-term battery storage. Yet, in the future, LDES could also be eligible for this application, especially for firming onshore and offshore wind capacities on a multi-day/week basis, or else solar PV capacities on a daily basis (EnTEC 2023). Due to its longer storage duration, LDES has the higher potential to reach all-around-the-clock capacity firming for renewables in comparison to short-term batteries, but as the market for these products (e.g., 24/7 clean PPAs) is not yet established, the higher costs of LDES in comparison to short-term batteries play a significant role for the competitiveness. According to a study from the US Department of Energy, LDES provide a distinctive advantage over li-ion batteries when the levelized costs of electricity (LCOE) of high time-matched PPAs (80% or more) are considered; i.e., reaching a firming level of 100% with LDES requires significantly less LCOEs than with batteries (US Department of Energy 2023).

Regarding the application *curtailment minimisation*, both short-term and longer-term duration energy storage can be utilised. The choice of a suitable storage duration is based on the duration of curtailment events. If those events surpass several hours or a development in that direction is anticipated, LDES might be attractive. Curtailment events are generally expected to increase in number, as renewable buildout is often faster than grid buildout. Currently, curtailment only affects few-hour-periods, but as an increasing amount of renewable capacity is built out and at the same time a significant amount of this renewable capacity is co-located with short-term batteries, the curtailment events might become longer and the opportunity for LDES arises increasingly. In some American markets such as Texas' ERCOT, curtailment already heavily affects solar generation, so that as of May 2022, more than 300 of the ca. 900 solar PV projects seeking approval involved co-located batteries (Solar Power World 2022). A project conducted by Orsted and Highview, a UK-based startup producing liquid air energy storage, is looking into storage options for Offshore Wind in order to reduce curtailment. In winter 2022/2023, curtailment has reached 1.35 TWh of wind energy (equivalent to powering 1.2 million homes) in the UK according to Highview (Maritime Executive 2023, City A.M. 2023). A similar project is conducted by Orsted and Energy Dome, looking into options how to combine Orsted's renewable generation and Energy Dome's CO_2 battery at one or several Orsted sites (Power Engineering International 2022, Energy Dome 2022).

The use case *curtailment minimisation* can even be extended to a seasonal level. A project aiming at seasonal storage is undertaken by Corre Energy, Eurowind Energy and Gas Storage Denmark, who are building a power-to-X project in Denmark, making use of renewable generation co-located to an electrolysis facility and producing hydrogen whenever there is more generation than demand available. The hydrogen produced from excess electricity is stored in salt caverns underground, either fuelling Corre Energy's CAES facility where compressed air is stored, or else in Gas Storage Denmark's facility as pure hydrogen where it can be stored for up to six months (Green Hydrogen Hub 2023).

For the application *grid connection constraints*, as for the other co-located use cases, both short- and longer-term duration energy storage are applicable. The decision about the necessary storage duration should be based on the available grid connection at the site as well as the anticipated peak generation of the renewable plant. For example, a small grid connection capacity in contrast to a large renewable park would call for a large-sized, longer-term duration storage asset to be able to feed in the generated electricity into the small-sized grid over a larger number of hours.

Regarding the application *enabling the renewable project to provide ancillary services*, it is rather likely that this application will not be the main source of revenues for renewable operators but only provide a minor upside and therefore also not determine the storage size and requirements. Other applications explained in this chapter here have a higher chance of increasing a hybrid project's profitability. Therefore, the question whether a short-term or long-term storage asset is more suitable depends on the revenue stacking potential. It has to be noted that the participation on ancillary markets requires specific characteristics from a market participation, such as response time, which also need to be considered when selecting a storage asset. These market requirements are discussed in chapter 4 .

In Figure 26, an overview of the market maturity for the co-location LDES business model in the is provided for the countries evaluated in this study. As explained in chapter 6.3.3, this evaluation is based on insights from Aurora's country experts, yet it has a limited information base and thus should not be interpreted as an extensive market overview.

	Market maturity rating	Reasoning
Germany	○	▪ No knowledge of announced projects for this business model
France	○	▪ No knowledge of announced projects for this business model
Italy	◐	▪ Energy Dome and Orsted plan a feasibility study on the deployment of a CO_2 battery (20 MW / 200 MWh / 10 hours storage) to store renewable generation at Orsted's sites
Spain	◔	▪ No knowledge of announced projects but there is interest in the market as evidenced by a study currently conducted by Aurora for Breakthrough Energy
Great Britain	◐	▪ Highview Power and Orsted plan a assessment on how to combine Orsted's offshore wind generation and Highview's liquid air storage ▪ Generally interest in the market

○ Very limited market interest ◔ Some interest ◐ Project(s) announced / under development ◕ Project(s) finalised ● Mature market

Figure 26: Assessment of market maturity for the co-location LDES business model

6.3.4 Regulatory best practices in the evaluated countries

The attractiveness of the co-location business model is influenced by the policies and regulations applicable in each country. Based on the detailed analysis in chapter 5.2, Table 29 provides an overview of possible policy measures that could further support the buildout of hybrid plants.

Best practices	Countries in which best practices are fulfilled
Policies that incentivise the build-out of hybrid plants (e.g., through feed-in tariffs, auctions, easier permitting process for installing hybrid plants or for "upgrading" existing renewable plants to hybrid plants)	Germany, Italy, Spain
Transparent regulation on market participation of hybrid plants (e.g., capacity market access)	Italy, Spain
Allowing co-located storage assets the withdrawal of power not only from the generating asset (renewable plant), but also from the grid, so that market participation and arbitrage options are improved	None of the evaluated countries – e.g., under current EU regulation, behind-the-meter co-located storage assets that receive subsidies are prohibited from grid power withdrawal

Table 29: Regulatory best practices for co-location

6.4 Customer energy management

Besides the stand-alone business model and the co-location with renewable energy plants, LDES facilities could also be used by electricity end-consumers. Since small li-ion storage units are usually sufficient for the needs of residential consumers, it is assumed that the LDES behind-the-meter business model will focus primarily on the C&I consumer segment. On the residential scale, LDES could be relevant to secure the electricity supply of multiple households or entire remote communities in so-called micro grids. In the countries covered by this study, however, the need for this application is considered to be small[35].

6.4.1 Potential applications

6.4.1.1 Maximisation of self-production and consumption of electricity

Self -production and consumption of renewable electricity is an emerging practice among C&I companies in Europe (RE-Source, 2020)[36]. In most cases, companies install solar panels on their buildings and/or the surrounding property and use the electricity generated for their operation (RE-Source, 2020). A further increase in self-generation of C&I companies can be expected in Europe, for both economic and regulatory reasons. As described in the first part of the study, the EU institutions are currently negotiating a legislative proposal to make solar installations on commercial buildings mandatory.

By complementing the renewable power source with a storage facility, C&I prosumers can maximise their self-consumption. During periods in which the company is not operating at full capacity, such as on weekends or holidays, the self-generated electricity can surpass demand. Instead of injecting this excess electricity to the grid, the company can store it in the LDES system. During periods of high electricity demand, the corporate prosumer can then use the stored electricity to power their operations, rather than drawing electricity from the grid. This can help to lower electricity bills and reduce the carbon intensity of electricity consumption.

6.4.1.2 Load shifting

Power load shifting refers to the practice of shifting the time at which electricity is consumed from one period to another, typically from periods of high demand to periods of low demand. This can be achieved through a variety of methods. For example, consumers may choose to manage the running times of energy-intensive appliances or machinery. Energy storage systems can be used to optimise and increase the flexibility of load shifting. For instance, some production processes might require a constant power supply which limits a companies' ability to adjust its power demand over time. A storage asset can then be used as a buffer and allows the company to vary its power grid offtake while keeping the power supply for the production process constant.

There can be several monetary incentives for C&I companies to engage in load shifting:

- Reducing electricity costs: When C&I companies choose to be exposed to variable electricity prices (for instance by procuring a part of their electricity on the spot market directly or by

[35] See US Department of Energy (2023) for an analysis of the microgrid business case.

[36] On-site thermal power plants (such as coal or gas power plants) have been used by large C&I companies to self-generate electricity for some time in Europe.

having a flexible electricity contract in place with a utility), they have an incentive to shift their load from high-price hours to low-price hours.

- Reducing grid tariffs through peak shaving: As explained in chapter 5.3 of this study, grid tariffs for C&I consumers often contain a power-based component that is dependent on the peak amount of electricity drawn from the grid (peak demand charge). Peak loads can be reduced by discharging the storage system and thereby lowering the amount of electricity required from the grid. See Figure 27 for an illustrative example.
- Achieving cost reductions with time-of-use network tariffs: Some C&I consumers may be subject to (or have the option to choose) variable grid charges (see chapter 5.3). If such a grid tariff regime is applicable, the storage asset can be used to shift grid withdrawal to hours in which grid fees are lower.

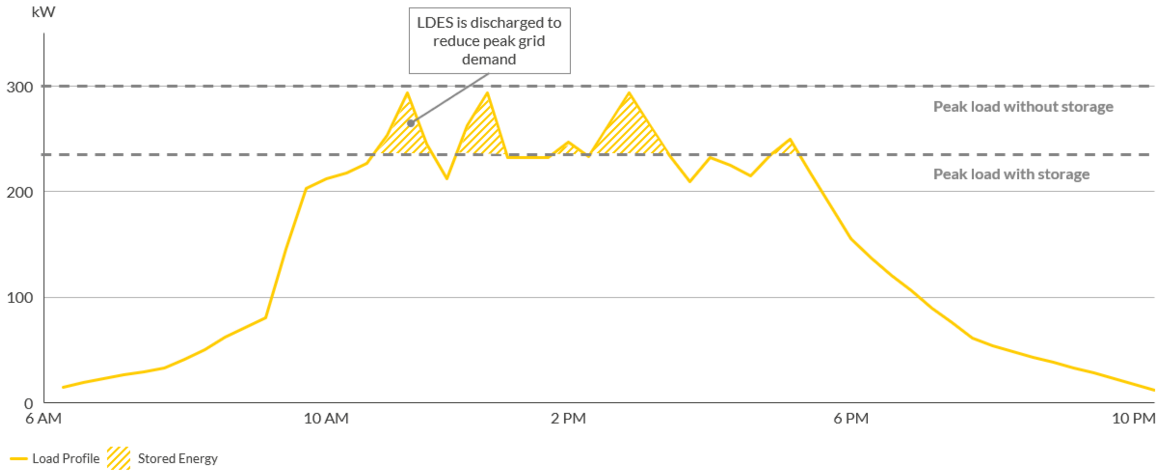

Figure 27: Application of an energy storage asset for peak shaving

6.4.1.3 Continuity of electricity supply

Energy storage systems reduce the reliance on the electricity grid and are therefore suitable to provide back-up power in the event of a blackout. When the grid goes down, an LDES facility could discharge to provide power to critical loads and protect sensitive equipment from damage. This can be relevant for critical infrastructure such as hospitals or facilities that are particularly vulnerable to power outages, such as data centres. In contrast to diesel generators which are the dominant technology used for back-up power today, energy storage systems provide a lower emission or even emission-free alternative (dependent on the electricity source from which the storage asset charges)[37].

[37] However, it must be noted that the core benefit of diesel generators is that scaling the back-up duration is simple and relatively low-cost (using a larger diesel tank). To be a competitive solution as back-up capacity for longer outage durations, it would therefore be important for the storage capacity of an LDES system to be saleable at low costs.

6.4.1.4 Arbitrage on wholesale and ancillary services markets

As described in detail for the stand-alone LDES business case, behind-the-meter storage facilities could also be used for arbitrage on wholesale electricity markets and for the provision of ancillary services. However, since C&I behind-the-meter storage assets usually have a much smaller storage capacity, an individual participation on wholesale and frequency ancillary services markets is in most cases either not feasible (for instance because the minimum bidding size requirements cannot be met) or the regulatory procedures and human resources required would outweigh potential benefits.

In many countries, market players called aggregators provide a solution to this entry barrier. Aggregators bring together a portfolio of flexible distributed energy resources (such as energy storage systems, but also electric vehicles and flexible loads) and manage them as a virtual power plant (VPP) to provide flexible capacity to wholesale markets, frequency ancillary services markets, and local flexibility markets (IRENA 2019). The owners of flexible distributed assets can benefit by receiving a share of the revenues generated by the aggregator. There is an increasing number of aggregation and management service providers for distributed flexible assets in Europe, reflecting the growing importance of these resources in the energy system[38].

6.4.2 Combination of applications

Table 30 provides an indicative assessment of how well the different applications of a C&I behind-the-meter storage facility can be combined. Overall, the applications *maximisation of self-production and consumption*, *load shifting*, and *arbitrage on wholesale and ancillary markets* can be combined relatively well with each other. For instance, if the primary use case of the LDES system for a C&I consumer is load shifting and the power demand profile of its production facility follows a regular pattern, the company could work out time periods in which the LDES is not required for its primary use and can instead be used by an aggregator to generate revenues on wholesale and ancillary services markets as part of a VPP. The objectives of maximising self-consumption and minimising demand peaks with load shifting can be combined as well.

The application that can be less well combined with others is the provision of back-up capacity. During normal operation, the back-up energy storage facility could in theory be charged and discharged to support the company's energy management or provide flexibility services to the grid. However, in the event of an unforeseen power outage, the energy storage system needs to have enough stored energy (i.e., back-up time) available to cover the blackout event. Therefore, it is crucial for an energy storage facility used as back-up power source to always maintain a certain state of charge. The exact level of state of charge that needs to be maintained will depend on factors such as the required back-up time, the reliability of the grid, and the facility's energy needs. Despite this constraint, combining the application for continuity of power supply with the other applications is still possible. For instance, recently announced energy storage projects for back-up capacity in data centres in Belgium and Ireland will also be used to provide flexibility services (Energy Storage News 2023a,b).

[38] Some of the main players active in Europe (with a focus on Germany) are *NextKraftwerke*, *sonnen*, *Energy2Market*, and *Next Energy Management*.

	Maximising self-consumption	*Load shifting*	*Market participation*	*Back-up power*
Maximising self-consumption				
Load shifting				
Market participation				
Back-up power				

Table 30: Indicative assessment of application combinations for C&I behind-the-meter storage[39]

6.4.3 Assessment of the attractiveness of the business model

According to the EnTEC energy storage revenue stream survey, the category "Services to Support behind-the-meter Customer Energy Management" is the least provided among energy storage technology and project developers with only 25% of respondents indicating to offer such services (EnTEC 2023). Within this cluster, services that can be assigned to the revenue stream *load shifting* are the most widespread, followed by *continuity of electricity supply* and *maximising self-production and consumption of electricity*[40]. On average, only 9% of the respondents' revenues is generated from the provision of behind-the-meter customer energy storage services.

The survey results align well with market trends for electricity storage deployment. According to the 2022 European Market Monitor on Energy Storage published by EASE and Delta-EE, C&I behind-the-meter storage buildout will only make up a small share of the expected overall storage capacity additions in Great Britain, Germany, France, and Italy until 2030 (Delta-EE)[41]. The largest potential is projected for the German market.

Just as with the other business models, LDES systems need to compete with short-duration batteries for market shares in the C&I behind-the-meter storage market. The market potential will therefore largely depend on whether LDES technologies can offer properties to companies that make it a better investment case compared to a conventional li-ion battery.

Regarding the revenue stream *Maximisation of self-consumption and load shifting*, a motive for a C&I prosumer to choose a LDES system could be to reduce the amount of electricity drawn from the grid as much as possible or even to become fully self-reliant. For instance, a short-duration battery would not be suitable to convert the intermittent production profile of an on-site solar PV installation to a constant 24-hour baseload power supply while a LDES system could fulfil this requirement[42]. This

[39] Combinations of applications that can be easily combined are coloured green. Yellow means that a combination is possible but entails certain limitations or restrictions. Red would mean that applications are not compatible.

[40] The services "End-User Peak Shaving "and "Time-of-Use Energy Cost Management" (as defined by EASE) are considered as load shifting applications.

[41] The publicly available insights of the study do not include a forecast for Spain.

[42] In areas with consistent solar irradiation or in summertime.

application is similar to the capacity firming application of renewable generators described in chapter 6.3.1.1. LDES facilities have already been installed for this purpose[43]. However, self-reliance based on renewable energy sources alone will not be an achievable goal for most C&I consumers with electricity intensive production processes.

Concerning the provision of *load shifting* services, LDES could be more attractive than li-ion batteries for companies that have a load profile that is characterised by extended peak demand periods and/or multiple contiguous peak loads per day (US Department of Energy 2023). This is because LDES systems can reduce peak loads over a longer time horizon and shave multiple contiguous demand peaks without degradation, which li-ion batteries are prone to when cycled repeatedly. In a recent study published by the US Department of Energy, the authors evaluate an illustrative case study in which an LDES system would be deployed for load shifting of a warehouse with a large EV fleet. According to the analysis, the LDES system would allow the company to achieve higher electricity cost savings compared to a short duration li-ion battery because of the higher reduction of peak demand charges (US Department of Energy 2023).

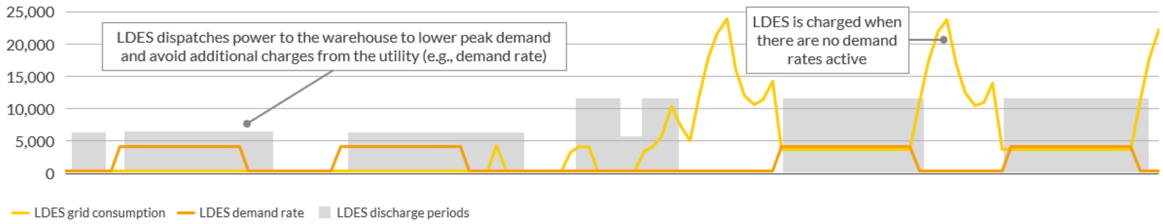

Figure 28: LDES dispatch for a warehouse with a large EV fleet, kW
(Source: US Department of Energy 2023)

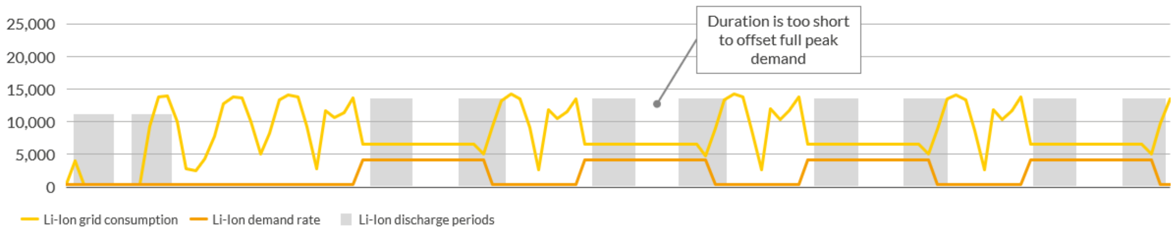

Figure 29: Li-ion battery dispatch for a warehouse with a large EV fleet, kW
(Source: US Department of Energy 2023)

Whether LDES systems are favoured over li-ion batteries for the provision of *back-up capacity* will likely depend on the specific energy storage duration requirements. In recent projects in Ireland and Belgium, Google and Microsoft opted for li-ion batteries to retrofit data centres and replace diesel generators (Energy Storage News, 2022a, 2022b)[44]. However, there are also examples of LDES systems being installed for data centre back-up, albeit not in Europe. In the USA, Microsoft commissioned a liquid metal based LDES system and the company Kinetic procured a vanadium flow battery for data centre back-up power use last year (Energy Storage News 2022c, 2022d). The reason why LDES seem to be more successful in the USA so far could be that power outages there are more frequent and longer

[43] For example, the U.S. long duration flow battery manufacturer ESS Inc. has recently installed its storage system at a technology recycling company in Pennsylvania, USA (ESS Inc. 2022).

[44] The battery system procured by Google has a 2.75MW/5.5MWh power to storage ratio that translates into a storage duration of roughly 2 hours.

lasting on average compared to many European countries[45]. Since major operators of data centres, such as Microsoft, Amazon, and Google, have committed to ambitious decarbonisation targets, the business case for energy storage in data centres can be expected to further increase in relevance.

There is so far no application of LDES for the provision of back-up electricity supply to hospitals known to the authors of this study. However, the usage of li-ion batteries in the health sector is suggested in the literature and already explored by some hospitals (cf. Mustafa et al. 2022, BBH 2022).

Across all C&I behind-the-meter storage applications, safety considerations can be another motive for companies to opt for an LDES system instead of a li-ion battery. While li-ion batteries can pose a fire hazard when overheated, there are LDES technologies available that consist of non-flammable and non-toxic materials. Amsterdam Airport Schiphol recently decided to deploy long duration flow batteries to replace diesel ground power units that are used to supply airplanes with electricity during ground time. According to the supplier ESS Inc., its LDES solution was selected for its superior safety performance (ESS Inc. 2023).

Figure 30 provides an overview of the market maturity of the C&I customer energy management LDES business model in the countries evaluated in this study based on market insights from Aurora's country experts.

	Market maturity rating	Reasoning
Germany	Very limited market interest	▪ Very limited market interest for this business model
France	Very limited market interest	▪ Very limited market interest for this business model
Italy	Very limited market interest	▪ Very limited market interest for this business model
Spain	Some interest	▪ No knowledge of announced projects but there is interest in the market as evidenced by a study currently conducted by Aurora for Breakthrough Energy
Great Britain	Some interest	▪ No knowledge of announced projects but some interest in the market, as evidenced by a recent inquiry about Aurora's capability to model this LDES business case

Very limited market interest · Some interest · Project(s) announced / under development · Project(s) finalised · Mature market

Figure 30: Assessment of market maturity for the C&I energy management LDES business model

[45] The average total duration of power outages per customer and year in 2020 was 1.3 hours in the US and only 0.3 hours in Germany (Worldbank 2023).

6.4.4 Regulatory best practices in the evaluated countries

Policies and regulations can have an impact on the attractiveness for companies to install a behind-the-meter energy storage facility. Drawing from the detailed analysis in the first part of the study, Table 31 provides an overview of policy measures that can provide an incentive for the C&I storage business model.

Best practices	Countries in which best practices are fulfilled
Policies that incentivise the self-generation of renewable electricity (e.g., through feed-in tariffs, net metering schemes or tax exemptions)	Germany, France, Italy, Spain, Great Britain (although to a lower degree)
Network tariff methodologies that increase the cost minimisation potential of load-shifting (ToU network tariffs)	France, Spain, Great Britain

Table 31: Regulatory best practices for behind-the-meter storage

6.5 Storage-as-transmission asset

LDES systems could be used by grid operators as an integral part of the power system infrastructure. The services performed by the storage assets overlap in part with the ancillary services applications described under the stand-alone LDES business model. However, the motive is different because instead of generating revenues, grid operators would use LDES systems to reduce the costs associated with operational management of the grid and to avoid investments in grid reinforcement and expansion. Besides, the rules for the ownership and operation of the storage asset by grid operators have specific implications for the combination options of possible applications.

6.5.1 Potential applications

6.5.1.1 Reduction of congestion management and grid upgrade costs

As described in chapter 4.5, grid operators in zonal electricity markets must increasingly intervene in market-based dispatch with congestion management measures in order to avoid grid congestion and ensure system stability. In a cost-based congestion management system (as in Germany), the costs arising from congestion management are first borne by the network operators and then passed on to the consumers via network charges. In Germany, the costs for congestion management increased significantly over the last few years and amounted to 2.3 bn € in 2021 (BDEW 2022).

One possibility to reduce or avoid grid congestion is the reinforcement and expansion of power lines. However, this is very cost-intensive, and progress is slow in some countries due to NIMBY problems and other issues. Another option to tackle the problem of grid congestion is to maximise the utilisation of the existing grid infrastructure by using energy storage as storage-as-transmission assets (SATA), also called *grid boosters* (Consentec 2023a; BMWK 2020).

Currently, TSOs operate transmission grids in a preventive way to ensure that even in the event of a single fault (such as a failure of a power line), the system can still be maintained within its operational limits (such as the maximum loadings of transmission lines and voltage corridors). As a result of the principle of preventive power system operation, transmission lines are typically not fully utilised in normal operation but only with a normal loading of below roughly 70% to ensure that spare transmission capacity is available if required in a contingency event (Consentec 2023a).

By transferring grid security requirements to storage systems, grid operators could shift from the preventive operation design to a reactive system operation design (i.e., after a fault occurred). This means that transmission lines could be operated closer to their maximum loading without undermining system security and as a result, grid congestions would become less frequent or even be avoided (Consentec 2023a). In the rare event that a system malfunction would cause the loading on a transmission line to reach critical limits, the SATA could be activated in conjunction with derating of generators to reduce the loading on the system. See Figure 31 for a visualisation of the functioning of the reactive grid operation concept.

	Preventive grid operation	Reactive grid operation
Normal operation	▪ Transmission capacity not fully utilised, therefore congestion management measures are necessary	▪ Fewer or no congestion management interventions necessary
Malfunction	▪ No additional measures necessary	▪ Automatic and coordinated activation of SATA and derating of renewable generation

Table 32: Comparison of preventive grid operation and reactive grid operation methods (Source: Consentec 2023a)

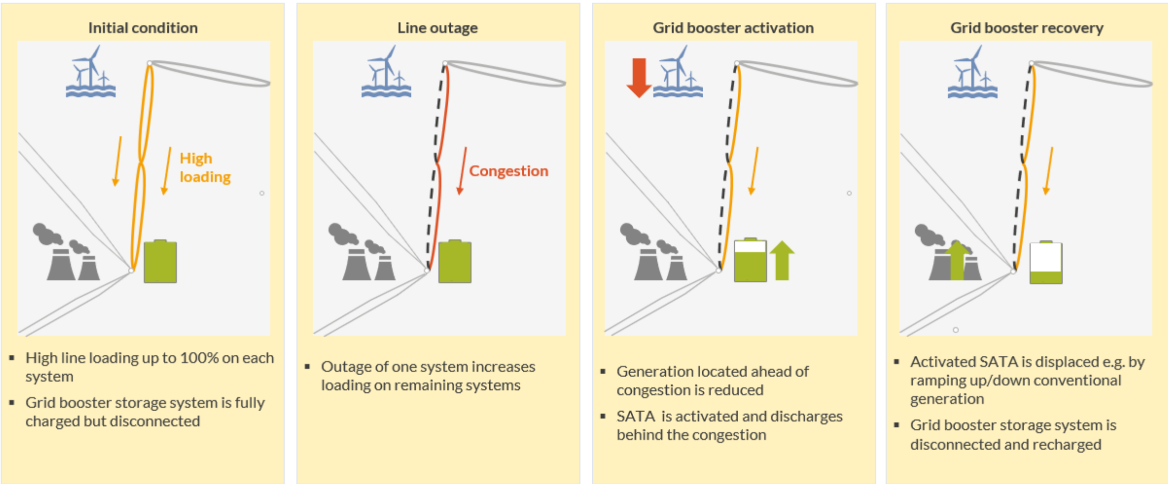

Figure 31: Schematic illustration of the reactive grid operation concept (Source: Consentec 2023a)

The benefits from the reactive grid operation would be lower congestion management costs (i.e., lower grid fees for consumers). Furthermore, the freed-up transmission capacity could allow more renewables to be connected to the grid. In some instances, reactive grid operation might even be sufficient to ensure that the existing grid infrastructure can match increasing demand and renewable generation. In this case, further significant cost savings would result from avoided investments in grid expansion.

6.5.1.2 Other applications

Next to their core application of ensuring grid stability in the event of system contingencies, SATAs could technically also provide other non-frequency and frequency ancillary services or participate on wholesale markets (Consentec 2023b; Fluence 2022). However, due to the unbundling requirements described in the first part of the study, grid operators in the EU and GB can only own and operate storage systems under specific derogations and are not allowed to participate in wholesale electricity, ancillary services, or capacity markets. The regulatory framework therefore constrains many other applications for SATAs. The provision of non-frequency services such as reactive power and black start is the most conceivable, as these are not procured on a market basis in most countries and therefore the self-provision by network operators would not cause market distortions (Consentec 2023b).

6.5.2 Combination of applications

In a recent study, Consentec (2023b) explained in detail how the main function of SATAs could be combined with various other applications ranging from other non-frequency ancillary services to the participation on frequency and balancing markets and even wholesale markets. However, as described above, the unbundling requirements for regulated grid operators currently constrain such revenue stacking options. Consentec (2023b) suggest that allowing for joint ownership models between TSOs and private market participants could be a regulatory option to enable full potential of the SATAs' flexibility services.

6.5.3 Assessment of the attractiveness of the business model

Using energy storage assets as integral part of transmission infrastructure is still a relatively novel concept. In Germany, a *grid booster* initiative was introduced in 2019 as an innovative concept of the Network Development Plan 2030 (BMWK 2020). Initially, two pilot projects with a combined capacity of 350 MW were planned. Since then, two more projects were announced. Recently, energy storage system manufacturer Fluence was awarded with developing one of the grid booster projects for the

German TSO TransnetBW which is expected to be completed in 2025 (Fluence 2022). Similar SATA projects or initiatives are currently under development in Lithuania, Australia, and Chile (Energy Storage News 2023e, Consentec 2023a).

So far, all the announced SATA projects deploy li-ion batteries. Since the use of storage for reactive grid operation requires very fast deployment, LDES systems would have to achieve ramp-up times comparable to li-ion batteries to be competitive. According to Consentec (2023b), the reaction time required will be as short as several tens of seconds. At the same time, the grid booster application does not necessarily require a long storage duration, as the energy storage facility only needs to maintain grid stability until a conventional power plant can be ramped up. For these reasons, it is rather unlikely that the use as SATA is a promising business model for LDES technologies at large scale. In regions in which conventional power plants are not available or will be retired, LDES could potentially be an option to be considered.

	Market maturity rating	Reasoning
Germany	◯	▪ Very limited interest for LDES in this business model
France	◯	▪ Very limited interest for LDES in this business model
Italy	◯	▪ Very limited interest for LDES in this business model
Spain	◯	▪ Very limited interest for LDES in this business model
Great Britain	◯	▪ Very limited interest for LDES in this business model

◯ Very limited market interest ◔ Some interest ◑ Project(s) announced / under development ◕ Project(s) finalised ● Mature market

Figure 32: Assessment of market maturity for storage-as-transmission asset LDES business model

6.5.4 Regulatory best practices in the evaluated countries

Against the background of the unbundling obligations resulting from market liberalisation for grid operators, a clear set of regulations is necessary for the using energy storage systems as SATAs. At EU level, this has been achieved with Art. 36 and 54 of the Electricity Market Directive. It is therefore important that the respective national laws and regulations are adapted accordingly to provide grid operators with a basis for making investment decisions in energy storage assets.

Furthermore, it is conducive if countries encourage innovative grid reinforcement measures as a complement to traditional grid expansion. In Germany (and in Austria and Switzerland), TSOs are obliged to consider network optimisation and reinforcement measures before planning new transmission lines (Consentec 2023a).

7. Conclusion

The liberalisation of electricity sectors across Europe has led to an increasing harmonisation of power markets and generally improved the market access conditions for operators of energy storage assets. In recent years, EU legislation has also strengthened the role of energy storage and addressed some of the major regulatory barriers to its deployment (such as lack of definition, double charges, and unclear ownership rules for grid operators).

Despite this progress, there are still considerable differences both in terms of the design of power markets in general and specific policies and regulations related to energy storage and its applications as is shown in chapters 4 and 5. With regards to the design of power markets and the mechanisms used for the procurement of ancillary services, the level of harmonisation and access to energy storage varies considerably between the type of market or service. While day-ahead and intraday markets are fully liberalised and to a large extent harmonised, there are still large differences in the design of capacity markets and ancillary services as well as in the access possibilities for energy storage to these markets and services.

Concerning the specific policies and regulations relating to energy storage and LDES there are clear differences between the countries as well. While the barriers mentioned above have been addressed in most national legislations, double grid charges (for the withdrawal and the injection of electricity) are still partly in place in France, for instance. Other countries (Germany and Italy) offer generous exemptions from grid fees and taxes for energy storage facilities. There are also differences in terms of whether the respective governments have defined national strategies for energy storage and whether there are financial support programmes for energy storage in general or even for LDES specifically.

Four potential business models are identified in chapter 6 of this study: (1) Stand-alone grid scale storage; (2) Co-location with renewables plants; (3) and (4) Storage-as-transmission assets (SATA). Based on an analysis of the respective market potentials, including a consideration of the advantages and disadvantages compared to short-duration lithium-ion batteries and an assessment of the project landscape, the business models *stand-alone grid scale storage* and *co-location with renewables plants* currently have the highest potential for LDES.

By creating a market design that provides multiple revenue streams for LDES and introducing policies aimed at promoting energy storage, policy makers and regulators can strongly influence the attractiveness of LDES business models and thereby encourage deployment. There are some general policies and regulations that are beneficial for all LDES business models. These include, for example, the complete elimination of disadvantages for energy storage with regards to grid charges, levies, and taxes. Another best practice is the formulation of an energy storage strategy including concrete deployment targets for energy storage in general or even LDES specifically.

In terms of market design, the establishment of capacity markets is conducive for LDES, as capacity contracts provide revenue certainty over a longer period and the storage depth of LDES is a competitive advantage over short-duration lithium-ion batteries. It is also important that the procurement of ancillary services is further liberalised and harmonised to reduce entry barriers for LDES. As more markets and services are opened to energy storage, regulators should also introduce clear rules and guidelines concerning the combination of various revenue streams (revenue stacking) to allow energy storage operators to maximise the revenue potential of their storage assets. This is important to improve the returns achieved with investments in energy storage projects and thus incentivise merchant buildout. All these aspects are particularly relevant for the stand-alone LDES business model, due to its focus on revenues from arbitrage and ancillary services. Within the geographic focus region of this report, these market design best practices are implemented to the highest degree in Great Britain.

To support the co-location business model, legislators should adopt policies that incentivise the build-out of hybrid plants (e.g., through specific auctions and by facilitating the permitting process). Such policies are in place in Germany, Italy, and Spain. Besides, regulators should set transparent guidelines for the market participation of co-located assets (e.g., for the participation in capacity markets). Finally, the EU requirement according to which co-located generators are not allowed to draw electricity from the grid if they are under a subsidy scheme could be reconsidered, as it severely restricts the possibilities of using the storage asset.

Policies and regulations can also have an impact on the attractiveness to install an energy storage facility for C&I companies. Policies that incentivise the self-generation of renewable electricity (e.g., through feed-in tariffs, net metering schemes or tax exemptions) are one option because energy storage systems are often used in conjunction with self-generation (i.e., to optimise self-generation). Another way to incentivise the buildout of C&I behind-the-meter energy storage systems is to apply time-variable grid charges.

While the market design features and regulatory best practices mentioned above improve the market outlook for LDES, tailored financial support policies will be required to bridge the cost gap to established technologies and accelerate LDES deployment. Some of the countries that were examined in this study are already in the process of launching such support mechanisms or are considering it (Italy, UK).

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