ASSET STUDY on

Which, where, when and how much flexibility and storage do we need to meet 2030 goals?

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Legal Notice

Luxembourg: Publications Office of the European Union, 2020

PDF ISBN 978-92-76-24731-9 doi: 10.2833/704092 MJ-03-20-696-EN-N

About the ASSET project

The ASSET Project (Advanced System Studies for Energy Transition) aims at providing studies in support to EU policy making, research and innovation in the field of energy. Studies are in general focussed on the large-scale integration of renewable energy sources in the EU electricity system and consider, in particular, aspects related to consumer choices, demand-response, energy efficiency, smart meters and grids, storage, RES technologies, etc. Furthermore, connections between the electricity grid and other networks (gas, heating and cooling) as well as synergies between these networks are assessed.

The ASSET studies not only summarize the state-of-the-art in these domains, but also comprise detailed qualitative and quantitative analyses on the basis of recognized techniques in view of offering insights from a technology, policy (regulation, market design) and business point of view.

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This study has been developed as part of the ASSET project by a consortium of Tractebel Impact , E3-Modelling and Guidehouse.

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Executive summary

The flexibility of a power system is its ability to accommodate both predictable and unpredictable changes in generation (e.g. coming from variable RES) and demand in a way that meets reliability standard and avoids (costly) curtailment. The ability of a power system to cope with large changes depends on the availability of flexibility means. Flexible thermal plants, storage technologies, demand response and RES with a better controllability can constitute important flexibility means. Furthermore, interconnections and reinforcements of the electrical grid are also a way to provide flexibility to the system, as it can help to balance the system over a wider area with smoother variations. In addition, the coupling of the electricity grids with the gas and heat grids can also provide additional flexibility through conversion and storage of energy which can be used to generate demand or generate electricity (power-to-gas and gas-to-power for instance).

Although the limited flexibility of power plants is not a new fact, traditional power systems with low variable renewables rarely faced problems due to this limited flexibility: the demand changes were largely predictable, and the variation was slow. On the contrary, in a system with high contribution by variable RES such as the future European electricity system, four sorts of variability occur, entailed by the different timescales of the temporal variabilities of RES and load. Firstly, the largely unpredictable variations in short or very short time intervals (e.g. drop of PV generation due to clouds, drop of wind generation due to wind gusts). Secondly, the largely predictable daily multi-hour variability, as for example due to solar. Thirdly, the also largely predictable variability over a few days due to meteorological conditions (e.g. wind regimes) or the weekday/weekend demand structure. Fourthly, the seasonal variability of the solar, wind and demand, that could lead to a weak availability of RES combined with a high load over a significant time period. The four types of flexibility need call upon different resources, in particular in terms of energy-to-power ratio and of time response. The short-term variability requires frequency reserves. The multi-hour daily and the weakly variabilities require power resources able to operate at low cost over a multi-hour schedule and at the same time have high ramping capabilities. The fourth type of variability requires long-term storage and/or thermal generating units in reserve. These variabilities occur in different points of the grid. Because the grid is not a copper plate (even within a country), balancing load and generation at a country level is not enough: congestions and voltage problems could occur at the transmission level or the distribution level. These grids constraints might have a significant impact on the storage/flexibility needs: they might determine where these means should be located, but they might also increase the needs (i.e. if they are not needed at the same time to balance the system at a national level and to solve local issues) and their characteristics (e.g. energy-to-power ratio) might be impacted.

In that context, this study aims at estimating which, where, and how much storage and flexibility will be needed in the European power system to meet 2030 goals, in the context of the EUCO30 scenario used for the examination of the “Clean Energy for all Europeans” package of 2016 -with the techno-economic assumptions used at the time[1]-, while considering the impact of grid constraints on flexibility needs. Although sector coupling can provide flexibility, the focus of this report is on the electricity system only. Consequently, flexible classical power plants, pumped hydro storage, battery storage and demand responses are the main sources of flexibility considered in this study.

As a prerequisite to the actual assessment of the needs, this report starts with a review of the main storage and flexibility means. These means can be divided in three

[1] The projection of storage and flexibility resources has been revised in 2018, using updated technology data, revised assumptions and an enhanced model. The present report does not present the updated results.

main categories: supply side flexibility, demand side flexibility and energy storage. On the supply side, flexibility can be tapped in conventional power plants, with technology developments allowing better ramping capabilities and lower technical minimum, but also directly in variable renewable energy resources. Indeed, they can provide upward and downward regulation, but it entails then a corresponding curtailment. On the demand side, industries can provide centralized flexibility, while households and commerce can provide decentralized flexibility. Finally, the two main technologies of energy storage appearing mature are the pumped hydro storage and the battery storage. In addition to the three main categories of flexibility means, power system transmission and distribution networks must be seen as key enablers of flexibility in the system, allowing the spatial sharing of flexibility resources. Another key enablers of an efficient use of existing flexibility and of investments into flexibility resources are the market and the regulatory frameworks. These two types of key flexibility enablers are analysed in this report.

After the technology review, the study analyses the expected needs of flexibility and of storage in 2030 in the context of the EUCO scenarios, and in particular of the EUCO30 scenario. These EUCO scenarios were prepared recently for the European Commission using the PRIMES energy system model for all EU member-states, and were part of the impact assessment of the proposals included in the "Clean Energy for all Europeans Package". The EUCO policy scenarios are variants built on the EU Reference Scenario 2016 that all achieve the 2030 targets (decided by the European Council) in terms of GHG emissions reduction, increase of renewables and increase of energy efficiency by 2030. The targets for 2030 are part of a longer-term effort that aims at reducing further the GHG emissions, setting a target of 80% GHG emission reduction by 2050. The driver of emissions cut in the power sector is carbon pricing in the ETS market and support schemes for renewables in various sectors. The energy efficiency effort decreases demand for electricity but electrification in heat uses and mobility over-compensate the decrease, and thus demand for electricity increases over time. The majority of the deployment of RES takes place in the power sector that sees a very significant increase of generation from stochastic sources, notably solar and wind. Different phenomena impact the needs for flexibility and for storage. Solar and wind energy sources present a periodicity in generation due to the meteorological conditions (sunlight, windy days, etc.) and partly randomness in generation due to unpredictable meteorological variability. At the same time, as the RES sources are often not dispatchable, the generation mismatches load due to demand for electricity. Therefore, the generation system requires energy for balancing generation from the variable RES. The first part of the analysis analyzes thus the storage and flexibility needs due to this variability at a national level in the EUCO scenarios, considering the limited interconnection capacity between countries. However, even if generation can match the load at a national level, congestions within the transmission or the distribution grid can hamper the transfer of electricity from the generators to the loads. Storage and flexibility means could thus be needed to alleviate these congestions. Consequently, the second part of the analysis focus on the impacts of the transmission and distribution systems on the flexibility needs.

The first part of the assessment of storage and flexibility needs, focusing on the balancing of load and generation at a national level shows that requirements of flexibility in the power system are expected to increase by 2030. It is mainly due to an important increase of variable RES, and primarily of solar PV, because the deployment of wind and in particular of offshore wind is of lower concern regarding the multi-hour flexibility requirement. In the EUCO context, the *needs for short and multi-hour flexibility* are projected to represent 21% of total electricity generation in 2030 in the EU28. Conventional ancillary services (mainly frequency restoration reserve) are able to handle almost half of the flexibility needs in 2030; more specifically by addressing short-term flexibility. However, the variable RES may also require additional services for short-term flexibility that go beyond the conventional reserves, as they may imply rising demand for fast-ramping short-term spinning reserves, in addition to current capabilities. Also, the system would experience by 2030 the emergence of fast-ramping as a systematic feature of the rising multi-hour flexibility. Comparing the flexibility needs in 2030 with the current levels (e.g. in 2015) has not been easy, as lack of data does not allow calculating the flexibility measurements fully. However, a rough estimation indicates that the flexibility needs are in the order of 10% of total electricity generation in 2015 in the EU28, of which a little above half are short-term flexibility needs covered by conventional ancillary services.

The needs for multi-hour flexibility will increase by 28% in absolute value between 2015 and 2030, going from about 3.3% of the total generation to about 4.0%. If we assume a full removal of market distortions, this increase of the needs can be met mainly by an increase of 12 GW of the storage capacity (+26%, mainly batteries and additional pumped hydro storage) covering around 16% of flexibility needs together with demand response, and by the natural replacement of old thermal power plants by new and more flexible thermal power plants. In other words, only a moderate increase of the flexibility means is expected by 2030 to balance the system at a national level. Nevertheless, it must be emphasized that the assumption of full removal of market distortions is a major prerequisite to reach that conclusion. Indeed, the removal of distortions allow for a larger sharing of the resources, which provide increased opportunities for the systems to use the (dispatchable) RES and the flows over interconnections as a source of flexibility: this assumption of perfect implementation of the market design initiative implies an almost doubling of power exchanges between areas within the intraday transactions, compared to a case assuming continuation of market distortions. As a consequence, an imperfect implementation of the market design initiative would result in the need of additional storage and flexibility means at a national level.

The second part of the assessment of storage and flexibility needs, focusing on the impact of congestions within the transmission or the distribution grid can hamper the transfer of electricity from the generators to the loads, shows that grid constraints might lead to significant additional flexibility needs. This is in particular the case for countries that are expected to host a large share of solar PV in their power system by 2030 (Italy, Spain and, to some extent, Germany). In order to quantify the needs, storage is considered to be the only flexibility provider. Nevertheless, it must be emphasized that other flexibility means (e.g. demand response such as load shifting) could also be used in complement or instead of storage.

For the distribution level, although the exact flexibility needs will depend strongly on the split between centralized and decentralized solar PV (i.e. if it is fully centralized, there will be no flexibility need in the distribution system), the analysis shows that, assuming storage it is the only source of flexibility, storage needs should be between 100 GWh and 300 GWh in 2030 (i.e. installed capacity between 50 GW and 150 GW, representing between 4.4% and 13.3% of the total net generation capacity), compared to a current situation with almost no storage within distribution systems. Note that electric vehicles could bring a large part of that flexibility: in the EUCO30 scenario, around 20-30 millions of electric vehicles are expected in Europe by 2030, which could represent a power of about 100-150 GW. Nevertheless, the actual contribution of electric vehicles will depend on the degree of smart charging[2]. This flexibility within the distribution grid could also be brought partially through load shifting (e.g. smart electricity based heating devices). Note that, in any case people will often want to store solar electricity from their solar panels for self-consumption, especially if their electric vehicles are stored in office buildings during the day time.

[2] The study METIS-S13 “Effect of electromobility on the power system and the integration of RES” analyses the role of smart charging.

At the level of the transmission system, storage could appear as an alternative to grid reinforcement, especially when the underlying congestions appear on long distances, which means that the comparison of cost-benefit analyses of storage and of transmission reinforcement could reveal storage as the best option, and when permitting issues are hampering transmission projects. The order of magnitude of the additional storage need (batteries) at transmission level would be of a few GW and a few tens of GWh, but the current organization of the power market in most Member States (as it stands before the transposition of the new market design rules) does not encourage such investments.

In a nutshell, in the framework of the EUCO30 scenario, additional flexibility/storage in 2030 is expected to be mainly needed at the level of the distribution system and mainly in some specific countries. A moderate increase of storage and flexibility means to balance the system at a national level and to manage congestions within the transmission system is expected. However, it must be noted that there is some uncertainty about the exact way the power system will evolve by 2030 and storage and flexibility needs might thus be slightly different from the values given in this report.

Finally, it must be emphasized that the share of variable RES will continue to increase and that a clear non-linear dependence of the flexibility needs on the deployment of variable RES exists. It will thus be important to prepare the system to absorb these large amounts of variable renewable energy sources during the upcoming decade.

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Introduction

The flexibility of a power system is its ability to accommodate both predictable and unpredictable changes in generation (e.g. coming from variable RES) and demand in a way that meets reliability standard and avoids (costly) curtailment. The ability of a power system to cope with large changes depends on the availability of flexibility means. Flexible thermal plants, storage technologies, demand response and RES with a better controllability can constitute important flexibility means. Furthermore, interconnections and reinforcements of the electrical grid are also a way to provide flexibility to the system, as it can help to balance the system over a wider area with smoother variations. In addition, the coupling of the electricity grids with the gas and heat grids can also provide additional flexibility through conversion and storage of energy which can be used to generate demand or generate electricity (power-to-gas and gas-to-power for instance).

The fact that some power plants have a limited flexibility (e.g. ramping up and down constraints, minimum up and down times) is not new. However, traditional power systems with low variable renewables rarely faced problems due to this limited flexibility. Indeed, the demand changes were largely predictable, and the variation was slow. The baseload plants (e.g. nuclear, coal and some CCGT units), which are inflexible, were first in the merit order as having the lowest variable costs and the mid peak load plants (e.g. some CCGT and OCGT units) followed in the merit order, thus had to shut down and start up, but at well planned time intervals. On the contrary, in a system with high contribution by variable RES such as the future European electricity system, four sorts of variability occur, entailed by the different timescales of the temporal variabilities of RES and load. Firstly, the largely unpredictable variations in short or very short time intervals (e.g. drop of PV generation due to clouds, drop of wind generation due to wind gusts). Secondly, the largely predictable daily multi-hour variability, as for example due to solar. Thirdly, the also largely predictable variability over a few days due to meteorological conditions (e.g. wind regimes) or the weekday/weekend demand structure. Fourthly, the seasonal variability of the solar, wind and demand, that could lead to a weak availability of RES combined with a high load over a significant time period. The four types of flexibility need call upon different resources, in particular in terms of energy-to-power ratio and of time response. The short-term variability requires frequency reserves. The multi-hour daily and the weakly variabilities require power resources able to operate at low cost over a multi-hour schedule and at the same time have high ramping capabilities. The fourth type of variability requires long-term storage and/or thermal generating units in reserve. These variabilities occur in different points of the grid. Because the grid is not a copper plate (even within a country), balancing load and generation at a country level is not enough: congestions and voltage problems could occur at the transmission level or the distribution level. These grids constraints might have a significant impact on the storage/flexibility needs: they might determine where these means should be located, but they might also increase the needs (i.e. if they are not needed at the same time to balance the system at a national level and to solve local issues) and their characteristics (e.g. energy-to-power ratio) might be impacted.

In that context, this study aims at estimating which, where, and how much storage and flexibility will be needed in the European power system to meet 2030 goals, in the perspective of the EUCO30 scenario- a scenario developed for the modelling exercises for the “Clean Energy for all Europeans” package and maintains the techno-economic assumptions used in 2015/2016 for that study[3]. Although sector coupling can provide flexibility, the focus of this report is on the electricity system only. The main sources

[3] The projection of storage and flexibility resources has been revised in 2018, using updated technology data, revised assumptions and an enhanced model. The present report does not present the updated results.

of flexibility considered will thus be the thermal power plants, the hydroelectric power plants, the dispatchable RES, demand response, pumped-hydro storage and battery storage. Different aspects of the European power system are considered in the estimation of the storage and flexibility needs: first the necessity to balance the load and the generation at a national level with the possibility to use interconnectors as a source of flexibility, and then the additional needs entailed by congestions in the transmission and in the distribution grids.
This report is then structured as follows. Because the optimal combinations of flexibility and storage solutions to meet the needs depend on their characteristics and costs of storage and flexibility means, chapter 0 first reviews these means. Then, chapter 0 evaluates the storage and flexibility needs. Finally, chapter 0 concludes. Two appendices complement these chapters: appendix 1 gives additional details on energy storage technologies and appendix 2 provides details about the methodology followed to assess storage and flexibility needs

Storage and flexibility means

Not only the flexibility needs of a power system are manifold, but also the means to provide flexibility. In addition to the supply side as traditional source, power system flexibility may also be provided by the demand side and energy storage. The electricity networks and markets play a key role in enabling flexibility and improvements in these areas, thus, are of importance, too.

General power system flexibility needs

Understanding the impact of variability on different operational timeframes is necessary to comprehend the flexibility requirements for systems with higher variable renewable energy (VRE) penetrations, which arise across all timeframes, see *Figure 1*. Adequacy for systems with high VRE penetration will require greater emphasis on ensuring sufficient flexibility. The seasonal behaviour of VRE should be incorporated to the long- to midterm scheduling to ensure that the system has the sufficient resources to adapt to these changes. Operational planning flexibility (day-ahead and intra-day) is key for ensuring that sufficient flexibility resources are online to enable secure operation under forecast uncertainty. Finally, operational flexibility is key for balancing net demand forecast errors and fluctuations.

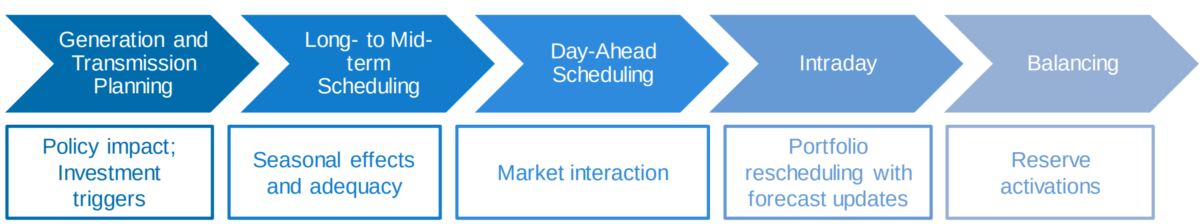

Figure 1: The impacts of variable renewables on the flexibility timeline. Based on Holttinen et al., 2013 [1].

The need for long-term flexibility options is increased with increased VRE penetration levels. For low VRE penetration levels, impacts are mainly visible in the shorter timeframes (operational flexibility, provision of balancing capability). Apart from market role (demand, supply, grid), we will present the overview of technologies in division for

a. **daily flexibility**, resulting from variations during the day, mainly caused by changing demand and solar PV infeed;
b. **weekly flexibility**, caused, e.g., by wind infeed;
c. **annual flexibility**, caused by electric heating patterns as well as wind and sun patterns.

Technology overview

The following sections provide an overview of flexibility technologies in the following categories:

- Demand
- Supply
- Energy storage
- Grid
- Market & regulation.

As shown in

Table 1: Overview of flexibility options across timeframes

, the different technologies are best suited for different timeframes.

Power system segments	Time scale		
	Daily flexibility	Weekly flexibility	Annual flexibility
Supply	§ Active power control of variable renewables § Conventional generation, especially gas power plants	§ Conventional generation	§ Conventional generation
Demand	§ Industrial demand side flexibility § Small-scale demand side flexibility § Power-to-heat		
Energy Storage	§ Batteries § Flywheels § Superconducting magnetic energy storage (SMES) § (Super-/Ultra-) Capacitors	§ Pumped hydro storage § Compressed air energy storage (CAES) § Heat storage (latent HS)	§ Power-to-gas § Heat storage (sensible HS)
Grid	§ Increased market capacity by coupling of EU transmission grid (interconnectors), and clear capacity calculation approaches § Increased grid/market capacity by PST and FACTS and dynamic line ratings § Higher system efficiency by advanced grid planning and operational tools		
Market & regulation	§ Market coupling § Access and prequalification criteria for ancillary services of aggregated resources		

	§ Scheduling times and gate closure tuned to allow for short to real-time updates of market actors § Complemented with long-term incentives/stability for investors § Transparency

Table 1: Overview of flexibility options across timeframes

Flexibility from variable renewable energy

Despite being the new additional source of variability in power systems, also variable renewables themselves are able to provide flexibility to the power system by so-called active power control.

Active power control of variable renewable power plants refers to the adjustment of the renewable resource's power production in various response timeframes to assist in balancing the system generation and load or congestion management. Wind turbines and PV installations have the technical capability for providing fast response to regulation signals (automatic or remote). By curtailing power production, these installations can provide down regulation. Up regulation can be provided, by operating units at generation levels below that which could be generated at a given time and increasing to the normal level as needed. Especially the second option comes at the expense of an overall reduction in VRE output and economic loss which makes its less attractive presently.

VRE are seen as key drivers for the system transformation and the need for new flexibility resources. Their participation in provision of flexibility can thus be a solution with major potential, especially for system with very high VRE shares. However, there are several challenges to implementing greater VRE controls. First, due to their stochastic nature, provision of flexibility from VRE is related to uncertainty. In addition, even though the installations have the technical potential to perform this task, often the regulatory / market environment present significant barriers. The actual use of the communication infrastructure between grid operator and power unit and the operational framework can pose key limitations to the realisation of this option as well. For example, in systems where renewable energy is subsidised, the renewable producer operates VRE to maximise the produced energy and has no incentive to curtail production.

Although, this option faces political and perceptual challenges associated with "wasting" clean energy, there can be significant cost savings for the power system by more intelligently operating renewable resources. For example, to the extent rapid changes in wind or solar output are expected due to large-scale weather fronts, or partly cloudy conditions, units can be constrained to more limited operating regimes—limiting lost generation to the so-called "tail events" for which large levels of balancing reserves would otherwise be needed. Nevertheless, active control of renewable generation is a common practice in smaller systems (e.g. islands) with limited flexibility resources, and in areas with high congestion levels.

Variable Renewables	Today	2030
Flexibility	Reaction time 100 %/min	Reaction time 100 %/min
Efficiency	N/A	N/A
Investment costs	Solar PV: 900-1500 €/kW Wind onshore: 1000-2200 €/kW Wind offshore: 3400-4700 €/kW	Solar PV: 800-1400 €/kW Wind onshore: 900-1800 €/kW Wind offshore: 2900-4500 €/kW
Variable costs	Annual O&M costs: ~2 % of investment costs	
Lifetime	Solar PV: 30 – 40 years Wind turbines: 20 – 25 years	Solar PV: 30 – 40 years Wind turbines: 20 – 25 years
Operational constraints	Availability directly depending on the natural resources sun and wind	

Installed capacity today	EU-28 in 2017 Solar PV: 104 GW Wind onshore: 152 GW Wind offshore: 14 GW Except for residential sources (part of the PV fleet), most of it can be considered a flexibility provider	
Maturity	High: VRE technologies have seen a strong (technological) development in the last decades. While there is still some room for improvement in technology and costs, it is little compared to past advancements.	
Environmental effects	Low	
Barriers	Economic barriers: opportunity costs due to lost production, depending on the payment for generation, curtailed installations have to be compensated, high technical and administrative effort for pooling small units Technical barriers: Specific technical equipment is needed to control installations remotely Political challenges: Lack of public acceptance (wasting "free" electricity)	
Potential flexibility functions	Due to marginal cost of zero, active power control (APC) of variable renewables can be used as a cost effective ancillary service like providing negative reserve control. Reduction of peaks in production due to a small level of curtailment can decrease the need of additional grid capacity With high penetration levels, APC can solve the problems in balancing the power system due to high feed in of VRE.	

Sources: [2], [3], [4], [6], [7].

Demand side flexibility

The demand side offers significant potential for low-cost flexibility and is the only flexibility option, apart from local storage, that can deal with certain impacts of a large share of distributed generation. However, the actual use of demand-side flexibility to date remains limited in various EU countries.

Demand side flexibility can be divided into large-scale industrial flexibility, e.g. active management of industrial load participating in balancing services, and small-scale flexibility potential inherent in the electricity demand of households and commerce, e.g. shifting of small electricity demand by a few hours.

Demand side flexibility - industry & commerce

Industrial demand is shaped by the characteristics of specific industrial processes and can vary among industries. Some industrial installations involve processes that offer a level of flexibility-- the potential to shift energy requirements of the process in time. Examples of such processes include electrolysis (high DR potential, very high intensive installations), cement and paper mills, electric boilers, and electric arc furnaces.

The provision of flexibility costs are generally modest if the primary process is not disrupted. Costs generally relate to change of shifts in personnel, installation of communication and control equipment, and potentially additional on-site storage of intermediary products. Costs associated with reduced production can be high and are usually avoided. The potential of the option is high and is easy to realize. However, its realization will depend on sufficient incentives. The framework conditions of the Clean Energy Package should cater for fair remuneration of flexibility.

Industrial Demand	Today	2030
Flexibility	Reaction time 20 – 100%/min Maximum period of shifting 1 – 24 hours	Reaction time 20 – 100%/min Maximum period of shifting 1 – 24 hours
Efficiency	95 - 100%	95 - 100%

Investment costs	Can be very low; reference value: 15 k€/MW/year	
Variable costs	Varies strongly	
Lifetime	N/A	
Operational constraints	Boundaries for flexibility set by production processes and proceedings within the companies.	
Installed capacity today	~20GW in EU [8]	
Maturity	Moderate, some industrial customers already provide interruptible loads on balancing markets	
Environmental effects	Low	
Barriers	Economic barriers: development of potential relies on electricity cost sensitivity and on price spreads in the electricity market. In most of the European markets, overcapacity prevents price peaks. In most of the industrial entities, the high organisational effort is not worth the cost savings by shifting demand to low price hours. Technical barriers: potential barriers for specific implementations can be uncertain potential, quality losses in products, short period of shifting, structure of demand (efficient usage of production capacity). Political barriers: some markets punish time differences in demand, e.g. by higher grid fees.	
Potential flexibility functions	Short-term and cost-efficient solution, additional potential for complete shut-down in minutes, but at much higher costs (value of lost load).	

Sources: [9], [10], [4].

Demand side flexibility - households & heat pumps

In the domestic and in the service sector, demand management can especially be applied in cross-section processes such as providing heating and cooling. This includes different levels of electricity demand, e.g. selective timing of the cooling of cold storage warehouses as well as automatic adjustments in the demand of refrigerators.

Other potential demand management technologies include air conditioning, compressing air for mechanical use or even rescheduling of washing processes in households. Some municipal water systems can provide the direct equivalent to pumped storage hydro by timing the reservoir refill to the needs of the power grid. Pooling of different demand potentials makes use the inherent reservoir storage. Demand management programs can enable two-way communication with loads even at residential level. The potentials are very high, but the enabling IT infrastructure and the constraints due to the primary use of controlled devices can present significant challenges still if full roll-outs still need to be done.

Small-scale Demand	Today	2030
Flexibility	Reaction time 100%/min Maximum period of shifting 1 – 24 hours	Reaction time 100%/min Maximum period of shifting 1 – 24 hours
Efficiency	95 - 100%	95 - 100%
Investment costs	Varies strongly, can be very low; reference value: 34 k€/MW/year	
Variable costs	Varies strongly	
Lifetime	N/A	N/A
Operational constraints	See barriers	
Installed capacity today	Low	
Maturity	Low	
Environmental effects	Low	
Barriers	Economic barriers: Necessary investments in IT infrastructure and data processing, few real time pricing tariffs available and market prices not visible to retail level. Accessing kilowatt-level for pooling loads can be very labour intensive, may have relatively high initial costs, and can take substantial resources to maintain, depends on the primary use of the equipment, which is not designed for flexible operation. It is expected that the implementation of the Clean Energy package will help to alleviate these barriers. Technical barriers: uncertain potential, missing communication	

	infrastructure Political barriers: Lack of acceptance or support, data security issues, coordinating utility interests and consumer interests can be a challenging paradigm shift. Especially for small-scale demand response other barriers including comfort, acceptance, privacy, awareness, and others can be significant.
Potential flexibility functions	Demand management might turn out to be the game changer in electricity markets, when flexible demand sets the marginal price in wholesale markets.

Sources: [9], [10], [4].

Power-to-heat

Electricity can be used to replace other fuels such as gas or oil for residential heating purposes. One option is direct resistance heating: an electric current through a resistor converts electrical energy into heat energy. Flexibility is provided by selectively energizing heaters and storing the generated heat for later use.
Thermal energy can be relatively efficiently stored in a number of ways, most commonly including insulated ceramic brick containers and hot water tanks. Heat is released as needed by the end user from storage. Electric heat pump technology offers a more efficient technology to convert electricity to heat. Heat pumps effectively move heat energy from a source of heat (e.g., ambient air) to the end use or storage.
Heat pump technology is most familiar in air conditioners and refrigerators. The principle is the same but the direction of heat flow is out of the ambient air from the conditioned space in cooling applications, whereas the flow is into the heated space in heating applications. Heat pumps are in fact reversible and can perform both heating and cooling functions—simultaneously in some applications.

Power-to-heat	Today	2030
Flexibility	Reaction time Up to 100%/min Maximum period of shifting Up to 24 hours	Reaction time Up to 100%/min Maximum period of shifting Up to 24 hours
Efficiency	Resistance Heating transfers 1 kWh of electricity to 1 kWh of heat. Efficient heat pumps with ground storage are up to 5 times more efficient.	
Investment costs	530 – 2560 €/kW for heat pumps	
Variable costs	1000 Euro/Liter – 50 Wh	
Lifetime	15 – 20 years	
Operational constraints	See barriers	
Installed capacity today	Unknown, yet high. Differs greatly between European countries, with France and Sweden being examples for very high shares of power-to-heat.	
Maturity	High	
Environmental effects	Low	
Barriers	Economic barriers: high costs for electricity if extracted from grid, especially for resistance heating (taxes and levies, grid fees). Efficiency of heat pumps a driver for their implementation Technical barriers: constrained due to primary operation (temperature limits), efficiency dependent on ambient air temperatures, use limited to specific period of the year Political barriers: fees, taxes, levies	
Potential flexibility functions	The electrification of the heat sector shifts demand from the heat to the power sector and can simultaneously add significant flexibility to the system. Combining thermal storage with electric heat has the potential to vastly increase the flexibility of the power grid, builds an optional place to put temporary surpluses of power from VRE, and reduce carbon by displacing fossil-fuel heat sources.	

Sources: [4], [11], [12].

Energy storage

Energy storage is an energy technology, which includes the following three processes: Charging, Storing and Discharging. Energy storage can therefore be seen as both generation and demand in the system, allowing the time-shifting of energy between periods of over- and under supply from VRE. Key options here are Capacitors, Superconducting Magnetic Energy Storage (SMES) and Flywheels for ultrafast charging and very short storing of energy; batteries (usually) for longer time storage (up to daily); and compressed air energy storage (CAES), pumped hydro storage and power-to-gas for longer duration cycles up to weeks. This section describes the main technologies for energy storage that will be considered in the assessment of the needs in chapter 0. Other technologies are described in Appendix 1.

Batteries

The relevance of batteries used in the energy system has increased drastically over the last years. 95% of the total deployed battery capacity in the European grid (approx. 350 MW) was installed between 2015 and 2018 [11]. The reason for the increased deployments is, that batteries can be used very flexible in a high number of different applications. Such applications vary from small decentral systems to reduce electricity costs / network tariffs by shifting demand and decentral PV supply for residential and commercial customers to large, utility scale applications to provide system services and to take part in electricity markets (e.g. frequency control, capacity markets). Batteries are light and are stackable, and they can be moved from one place to another[4], meaning that energy or power ratings can easily be added or subtracted to a storage system. The cost of battery storage has dropped drastically and faster than expected due to economies of scale (driven also by batteries produced for consumer electronics and electric vehicles) and research efforts.

There is a great variety of battery technologies with different advantages and disadvantages as well as diverse technology/market readiness levels (see technology factsheet). All battery technologies function with the principle of converting electricity to chemical potential for storage and then back to electricity. Batteries can be broken down into three main categories:

1. Conventional batteries, that are composed of cells which contain two electrodes (e.g. lead acid, lithium ion),
2. High temperature batteries that store electricity in molten salt (e.g. NaS (sodium-sulphur))
3. Flow batteries that make use of electrolyte liquids in tanks, energy and power ratings can therefore be decoupled (e.g. Zinc-Bromine Redox-Flow, Vanadium Redox-Flow). [4]

Most deployed and announced grid applications in Europe are currently using Lithium-ion system (Li-ion) and Sodium-sulphur (NaS) batteries. Lead-acid batteries are very mature technologies that have been used for centuries and are mostly used to provide back-up services. [11]

Research on batteries is ongoing to further increase energy and power density, reduce costs and ensure safe and durable operation of batteries. By experimenting with new anode and cathode materials or by enhancing the design and set up of the modules, new technologies with different characteristics are tested and introduced to the market.

Batteries	Today	2030
Flexibility	Energy/power ratio (e.g. MWh/MW, discharge time) Usually from 4 to 1 (up to several hours); depending on application and technology	

[4] This is obviously not the case for pumped hydro storage.

Efficiency	85-95%
Investment costs	Depending on power and energy levels: Lead-based: < 120-200 €/kWh Li-ion: 200 - 500 €/KWh Redox Flow: 80 – 500 €/kWh; 250 – 600 €/kW
Variable costs	Unknown
Lifetime	10 - 20 years; 5,000 - 10,000 cycles
Operational constraints	§ Hardly limited by resource availability, but potential resource bottle necks due to sourcing in politically instable countries § Limited by costs compared to other flexibility options § Limited by battery Li-Ion production capacities (current EU capacities 2 GWh/year, announced: > 60 GWh/year in Europe) § Limited by revenues and feasible market options (e.g. Frequency containment reserve (FCR) market limited to 3 GW in Europe by design
Installed capacity today	EU-28: ~0.9 GW
Maturity	§ **Mature**: Lead-acid, Nickel-based § **Commercial**: Li-ion, NaS (sodium-sulphur) and NaNiCl2 (Zebra), Flow batteries (Zinc bromine, Vanadium), Zinc-air, Li-polymer § **Demonstration**: Advanced lead-acid, Na-ion, Hydrogen bromine flow batteries, LiS § **Prototype**: FeCr (iron chromium) § **Laboratory:** Advanced Li-ion, new electrochemical couples (other Li-based), liquid metal batteries, Mg-based batteries, Li-air and other Metal-air batteries, Al batteries, nonaqueous flow batteries, solid-state batteries, batteries with organic electrodes § **Idea /concept:** Solid electrolyte Li-ion batteries, rechargeable Me-air batteries (Mg-air, Al-air and Li-air)
Environmental effects	Low
Barriers	Economic barriers: High investment costs with short lifetimes, some resources have been scarce, e.g. Lithium Technical barriers: Stability of some batteries are a concern, NaS: high temperature needed to keep salt molten (>300°C)
Potential flexibility functions	Mainly small-scale application at moderate level of RES penetration. High potential for technical development and cost-reduction Could be used at residential/building and distribution grid level, while complementing pump storage and other “big scale” technologies work on the transmission grid level Li-ion: High energy density, Power quality, Network efficiency, Off-Grid, time shifting, electric vehicle Lead Acid: Off-Grid, Emergency supply, time shifting, power quality

Sources: [13], [14], [15], [12], [11].

Pumped Hydro Storage

Pumped hydro stores energy mechanically, by using electricity to pump water from a lower reservoir to an upper reservoir and recovering the energy by allowing the water to flow back through turbines to produce power, similar to traditional hydro power plants. Pumped storage technology is mature, has low O&M costs and is not limited by cycling degradation. Capital costs tend to be high and very specific siting requirements are needed. Costs are highly situational, depending on size, siting and construction.
Most energy storage installed and operational in Europe and worldwide are pumped hydro storage system. They account for more than 90% of the total storage capacity worldwide.

Pumped Hydro Storage	Today	2030
Flexibility	Energy/power ratio (e.g. MWh/MW, discharge time) Several days	
Efficiency	70 - 85%	
Investment costs	New installations: 350 – 2,000 €/kW Extension of existing plants: 850 – 1,300 €/kW Small Scale: 1,875 – 3,225 €/kW	
Variable costs	103.5 – 322.5 €/kWh (Large - small scale)	
Lifetime	>50 years	
Operational constraints	See barriers	
Installed capacity today	EU-28: 45.3 GW	· Theoretical EU potential: 54 TWh, when a maximum distance of 20 km between the existing reservoirs is considered · Realizable potential (including constraints such discounting populated areas, protected natural areas or transport infrastructure): 29 TWh · Potential is between 2 and 3.5 times the existing pumped hydro storage capacity.
Maturity	§ Very mature, largest capacity additions in Europe between 1970s and 1980s	
Environmental effects	Low	
Barriers	Economic barriers: Long return of investment (> 30 years) Technical barriers: low energy intensity, very specific siting requirements, only possible at limited number of sites Political barriers: low public acceptance or support due to substantial environmental impact, high requirements in approval process	
Potential flexibility functions	Mostly used as an energy management technology, ideal for load levelling and peak shaving, time shifting, power quality measures, and emergency supply	

Sources: [12], [15], [16], [11], [3].

Power-to-gas (Gas storage)

Large amounts of energy can be stored in the form of gas (hydrogen and other synthetic gases). In a first step an electrolyser technology uses electricity to split water (H2O) into hydrogen (H2) and oxygen (O2)[5].

[5] Also other technical gasification solutions exist to make synthetic fuels; these are not considered in this report.

Hydrogen can then directly be used or be further combined e.g. with carbon to create methane. Methane is the main constituent of natural gas and therefore the synthetic gas can be injected to the existing infrastructure for natural gas (gas grid and gas storage). The gases have numerous potential uses: they can either be burned in gas turbines to produce electricity or they can be further treated to be used as synthetic fuels (e.g. for the transport sector) or in industries.
The advantage of the technology is that large amounts of energy can be stored over long periods of time. Storage capacities such as caverns or the gas infrastructure are proven technologies for several decades and are considered as a safe and cost-effective solution for large-scale storage.

Power-to-gas (Gas storage)	Today	2030
Flexibility	Energy/power ratio (e.g. MWh/MW, discharge time) Days to months	
Efficiency	30-45%	
Investment costs	~3600 €/kW	
Variable costs	20 – 40 $/GJ green hydrogen (fixed h/year + electricity cost component $/kWh)	
Lifetime	10 – 30 years; 1000 – 10000 cycles	
Operational constraints	See barriers	
Installed capacity today	Low, around 21 MW	
Maturity	§ Different maturity levels exist for different electrolyzing technologies, different conversion and different types of utilization § Alkaline electrolysis is a mature technology, while for other conversion systems such as proton exchange membrane (PEM) cells only some pilot plants exist § There is good experience of hydrogen / methane used in industry, while the transformation of the P2G products back into electricity or to use as alternative fuels is currently in the demonstration phase.	
Environmental effects	Low	
Barriers	Economic barriers: still high costs, technological innovation necessary Technical barriers: low efficiency, external source of CO2 necessary or extraction from the air (further reduction in efficiency)	
Potential flexibility functions	Seasonal storage, likely to be used in the transportation sector first. The technology raises the prospect of relying on 100% renewable resources by storing surplus electric power in the gas infrastructure and relying on natural gas power plants when VRES generation is low.	

Sources: [12], [15], [16], [11].

Grid

Power system transmission and distribution networks are a key enabler of flexibility in the system, allowing the spatial sharing of flexibility resources. Strengthening the network and alleviating congestion effectively reduces VRE variability by netting often-offsetting changes in generation over larger geographic areas. Key options here are increasing the capacity of network lines (HVAC or HVDC technology) or improving the network utilisation by adding power flow control devices (like Phase Shifting Transformers, FACTS devices, HVDC lines).

Increased market capacity by coupling of EU transmission grid (interconnectors)

The market size can be extended by integrating neighbouring markets. Prerequisite is the physical access to neighbouring markets via grid capacity and the existence of market rules that allow the efficient cross-border trading of flexibility. In market coupling, instead of explicit trading of transmission capacity between markets, total supply and demand are matched over different market areas to use existing grid capacity in the most efficient way.
In Europe, TSOs invest heavily in cross-border transmission lines and cables as well as transformer stations, which are mature and well-established technologies. Cost for selected projects range from 2 million to 3.8 billion €.

Increased market capacity by PST and FACTS

Congestions in meshed networks can be resolved by redirecting power through alternative pathways. For active power control, Flexible AC Transmission Systems (FACTS) can be installed. FACTS include a wide range of power electronic technologies which are used to enhance the flexibility of power transmission. Phase-Shifting Transformers (PST) are a key technology that allow to control the power flow without generation rescheduling or topological changes. PSTs can introduce a phase shift between voltage phasors, independently from the throughput current. PSTs do not increase the capacity of the lines themselves, but if some lines are overloaded while capacity is still available on others parallel to them, optimising the power flows with PSTs can increase the overall grid capacity.
PST are a mature technology, used by TSOs in Europe for power flow control through preventive or curative strategies. However, the speed of phase shifting transformers for changing the phase angle of the injected voltage via the taps is very slow. Phase shifting transformers and similar devices using mechanical taps can only be applied for very limited tasks with slow requirements under steady state system conditions.
TYNDP examples of FACTS and PST show a capacity range of 450 - 1630 MVA as well as costs of 13 – 35M€ per project. While they can be considered mature technologies and have been used by European TSOs for more than 15 years now, the potential range of application for FACTS and PST is limited. They can only be applied for very limited tasks and require slow operation under steady state system conditions.

Dynamic line ratings

Dynamic Line Rating (DLR) also known as Real Time Thermal Rating (RTTR) of lines or cables is rather mature technology where the thermal rating is controlled in real-time. It aims at maximising the transmission capacity while respecting the safety margins (e.g. sag). This is possible through improving the observability and thus relating to the actual temperature rather than the current rating. Enhancements of +40% to +100 % compared to static line rating have been observed
Technologies that enable DLR are sensors (ambient temperature, line temperature, wind speed, tension, sag, irradiation, power angle) and monitoring systems, including communication.
The following DLR types exist:

- Weather forecast (WF): Real-time weather data is collected near the conductor or transformer and ratings are set according to the forecast
- Conductor temperature evaluation (CTE): Conductor temperature is measured with the help of temperature sensors and ratings are adjusted accordingly
- Tension monitoring (TM): Calculation of sag through measurement of tension

(Usually applied in combination with weather monitoring)

- Line sag measurement (CSM): Accurate measurement of the line sag through measuring the sag in the most critical parts of the transmission corridor
- Clearance-to-ground measurement (CTGM): Measurement of clearance to ground instead of sag
- Full scale monitoring (FSM): This method can be combination of several cases proposed above. Numerous sensors are placed along the line which makes this the most expensive and precise method.

Dynamic line rating is a mature technology that is already applied in Europe. Investment costs of project examples range from €1.27 million for three 239 kV transmission lines of the NYPA project to €6.5 million for five 345 kV lines and three 138 kV transmission lines of a project in Texas, while related cost reductions are estimated as a multiple of the investment costs.

Higher system efficiency by advanced grid planning and operational tools

Advanced software and integrated planning solutions can be used to improve the integration of distributed energy resources (DER). All methods have the goal to increase the flexibility and the utilization of the grid and to decrease costs. The following concepts fall under this category:

- *Probabilistic Grid Planning Criteria*: With new loads and fluctuating infeed, static grid planning does not enable the desired utilization of the grid. Probabilistic methods using stochastic inputs to assess reliability are better suited to deal with uncertainties like location of future generating units and has the potential to increase the grid's utilization and thus decrease costs while maintaining the high security standard.
- *Large-scale DC Overlay Grid concepts*: DC overlay grids are evolutions of the AC interconnected system developed over past decades. Due to a strong shift in type and location of generation, an incremental evolution of the AC system does not always give the most cost-effective and timely solutions. Integrating DC corridors in the meshed AC system can be a solution.
- Enhanced Operational Planning Processes
- *Enhanced Load Forecasting*: Enhanced load forecasting goes beyond the traditional method based on economic activity and temperature forecast. New methods try to leverage the power of big data and predictive analytics to better understand customer decision-making and sensitivity to variable prices. Customers get clustered and the forecast is probabilistic based on the likelihood of customers adoption of a technology and reaction to variable prices
- *Enhanced RES Infeed Forecasting* (wind only) can be classified into
    - Physical / deterministic method using meteorological data to obtain wind speeds forecast and convert it into wind power. Forecast are based on numerical weather predictions (NWP) using weather data like temperature, pressure, surface roughness and obstacles
    - Statistical method based on historical data without considering meteorological conditions. It usually involves artificial intelligence (neural networks, neuro-fuzzy networks) and time series analysis approaches (machine learning)

  - o Hybrid method combining physical methods and statistical methods using weather forecasts and time series analysis approaches (machine learning) [1]"

- § Enhanced Market Modelling Tools
- § Enhanced Grid Congestion Forecasting

These concepts bare great potential for improved grid operation, which are highlighted by pilot projects. The mean prediction errors dropped from 10-20% to 2-5% with advanced RES forecasting in Petrolina, Brazil, while the German Study "Network Stress test" found that with Probabilistic Grid Planning Criteria up to 85 % of congestions can be avoided.
Single technologies as ,e.g., enhanced RES forecasting are commercially available. Global demand is expected to grow with 70 GW of wind power plants per year and is expected to reach a cumulated capacity of 800 GW by 2021. Other tools like prototyping for Enhanced Load Forecasting show some successfully implemented pilots in the USA.

Market & regulation

Markets and regulation are the key enabler of an efficient use of existing flexibility and incentivise additional investments into flexible capacity.
The operation of modern power systems is defined by the trading of electricity in a set of interconnected liberalised markets. Electricity markets are generally divided in long term (futures), day-ahead and intraday spot markets. Short term flexibility is traded in balancing markets, which are responsible for the organisation of the control power required to physically balance short term deviations between demand and supply.
There are specific market improvements in the design and operation of markets that can help uncapping the system flexibility potential. The effectiveness of these rules depends on the specific characteristics of a system.

Market coupling

The market size can be extended by integrating neighbouring markets. Prerequisite is the physical access to neighbouring markets via grid capacity and the existence of market rules that allow the efficient cross-border trading of flexibility. In market coupling, instead of explicit trading of transmission capacity between markets, total supply and demand are matched over different market areas in order to use existing grid capacity in the most efficient way.

Prequalification standards

Market actors have to fulfil specific prequalification standards before they are allowed to trade on electricity markets. Especially in balancing markets, these standards comprise a number of technical characteristics that have to be met, e.g. minimum sizes of bids. Pooling of small entities opens the market to bids from additional flexibility options, including demand side options and controlled generation of VRE.

Scheduling times

Services on electricity markets are traded in defined time blocks. Shorter scheduling periods for fulfilling the contract opens the market especially for VRE and for bids from the demand side. VRE and demand side actors often provide flexibility only for a certain time frame, e.g. in day-time. If the predefined time blocks are too long (e.g. 12 hours, or one week), these flexibility options are excluded from the market. Note that the implementation of the Clean Energy package should help to shorten the scheduling periods. Allowing transactions within operating periods can further reduce the need for control power and increase schedule accuracy.

Gate closure

VRE forecast accuracy increases over time: the closer the fulfilment period, the better the forecast. Delaying gate closure closer to real-time includes better forecasts for VRE. With lower uncertainty, the need for balancing reserves decreases.

Capacity payments

Some flexibility options have low variable costs, but high investment costs. Compensation by marginal costs does not give incentives to develop these sources of flexibility. Capacity payments may open the market for additional flexibility options, but should basically be used as a last resort, when other options do not work, in line with the Clean Energy Package. Strict conditions are to be respected to ensure market distortions are excluded/minimised.

Transparency

Market results, such as reserve and imbalance prices, should be published as soon as possible. Time lags hinder adjustments by market actors.

All suggested improvements can open the market to new actors. A large number of suppliers in the market brings prices for balancing reserves down.

Storage and flexibility needs

Introduction

This chapter analyses the expected needs of flexibility and of storage in 2030 in the context of the EUCO scenarios, and in particular of the EUCO30 scenario. These EUCO scenarios were prepared for the European Commission in 2015/2016 using the PRIMES energy system model for all EU member-states, and were part of the impact assessment of the proposals included in the “Clean Energy for all Europeans Package”. The EUCO policy scenarios are variants built on the EU Reference Scenario 2016[6] that all achieve the 2030 targets (decided by the European Council[7]) in terms of GHG emissions reduction, increase of renewables and increase of energy efficiency by 2030. The targets for 2030 are part of a longer-term effort that aims at reducing further the GHG emissions, setting a target of 80% GHG emission reduction by 2050.
The EUCO scenario exercise was prepared in 2015/2016 and was used as a basis for the work undertaken in this study in spring/summer 2018 before the preparation of the “Clean Planet for All Communication”[8]. The EUCO scenarios were based on the best-available knowledge on techno-economic assumptions of the time, including projection of technology costs, assumptions about maturity levels, efficiencies, etc. and their developments over time. The results of this modelling exercise reflect the

[6] https://ec.europa.eu/energy/sites/ener/files/documents/ref2016_report_final-web.pdf
[7] http://www.consilium.europa.eu/uedocs/cms_data/docs/pressdata/en/ec/145397.pdf
[8] https://ec.europa.eu/clima/policies/strategies/2050_en

achievement of RES and EE targets for 2030, as defined in the EUCO scenarios, before the agreement on new targets during the summer of 2018 for renewable energy and energy efficiency (confirmed by parliament in November 2018). An update of the modelling exercise has been performed in preparation of the Communication a “Clean Planet for all”[9], which was undertaken after the completion of this study. The scenarios for the “Clean Planet for All” use an updated version of the set of techno-economic assumptions[10]. The trajectory of costs for renewable energy technologies for power generation follow a stronger decrease, which reduce the RES technology costs already in 2030. Costs for storage technologies, mainly batteries, are also lower due to the latest developments in the R&D, as observed in the current years and a higher maturity level is assumed to achieved already in 2030. The scenarios developed for the “Clean Planet for All” Communication reflect the achievement of the updated 2030 targets, and embed these targets in a long-term transition towards deep emissions cut by 2050. Consequently, the updated modelling shows a different development of storage and a different management of flexibility in 2030, compared to the EUCO scenario context. The difference is the higher use of batteries and a higher easiness in addressing flexibility requirements driven by the fast growing variable renewables. The present report does not include the updated modelling results.

The driver of emissions cut in the power sector is carbon pricing in the ETS market and support schemes for renewables in various sectors. The energy efficiency effort decreases demand for electricity but electrification in heat uses and mobility over-compensate the decrease, and thus demand for electricity increases over time. The majority of the deployment of RES takes place in the power sector that sees a very significant increase of generation from stochastic sources, notably solar and wind. More specifically, the EUCO30 scenarios involve GHG emissions reduction of 40% in 2030 (compared to 1990), 27% RES in total gross demand for energy and 30% lower total primary energy by 2030 relative to a projection performed using PRIMES back in 2007.[11]

Different phenomena impact the needs for flexibility and for storage. Solar and wind energy sources present a periodicity in generation due to the meteorological conditions (sunlight, windy days, etc.) and partly randomness in generation due to unpredictable meteorological variability. At the same time, as the RES sources are often not dispatchable, the generation mismatches load due to demand for electricity. Therefore, the generation system requires energy for balancing generation from the variable RES. The variability of RES often implies that the balancing energy must have the power to increase or decrease rapidly, as well to have fast responsiveness. The first part of this chapter, section 0, will thus analyze the storage and flexibility needs due to this variability at a national level in the EUCO scenarios, considering the limited[12] interconnection capacity between countries based on the hourly analytical

[9] See footnote 8

[10] The assumptions for the Clean Planet for All communication were consulted and published within another ASSET study: “Technology Pathways in Decarbonisation Scenarios” https://ec.europa.eu/energy/sites/ener/files/documents/2018_06_27_technology_pathways_-_finalreportmain2.pdf

[11] Although during the summer of 2018 the renewable targets have been updated, this study remains nonetheless valid as it provides an indication of why and in what order of magnitude flexibility and storage are needed to the horizon of 2030.

[12] The interconnection capacity in Europe is physically limited to existing lines (the model takes in account projected developments according to the TYNDP of ENTSO-E); interconnector capacities are limited by their nominal capacity constraints and the NTC values. To different cases of interconnector capacity are analyzed within this study.

simulation of the interconnected power systems performed using the PRIMES-IEM[13] (internal electricity market) simulator which has been used to assess policy options of the new electricity market design that was part of the "Clean Energy for all Europeans" proposal of end 2016. However, even if generation can match the load at a national level, congestions within the transmission or the distribution grid can hamper the transfer of electricity from the generators to the loads. Storage and flexibility means could thus be needed to alleviate these congestions. Consequently, sections 0 and 0 analyze the impact of the transmission system and of the distribution system, respectively. Finally, section 0 synthetizes the needs.

Storage and flexibility needs to balance load and generation at a national level

Introduction

The aim of this section is to measure flexibility needs in the context of the EUCO scenarios to assess whether flexibility is a challenge for the power system and the resources that provide flexibility services. We use the projections based on the full PRIMES energy system model and on the hourly simulations of the power system performed using the PRIMES-IEM model. The latter uses the PRIMES-based projection as a setup of boundary conditions and on this basis it performs more detailed high-resolution simulation of the sequence of the wholesale and balancing markets and the system operation. The hourly simulation includes random events to simulate randomness of RES availability, represents in detail the technical operation constraints of individual power plants and performs a pan-European market coupling, across all market stages, through power flows over the interconnections. Based on the results of the PRIMES-IEM simulation, which performs a detailed, market-oriented, simulation of the EUCO scenario for the year 2030, we calculate flexibility metrics to evaluate the flexibility and storage needs related to the achievement of the 2030 targets.

Market design cases simulated using the PRIMES models

In the context of the EUCO30 scenarios, we evaluate the flexibility requirements in two cases, which reflect different market designs, as defined in the impact assessment studies for the electricity market design[14] that accompanied the "Clean energy for all European" policy proposal.

The first case (Option Case 0) reflects a business as usual continuation of the electricity market practices that prevail currently. The study has identified several market distortions in the current practices, which by assumption continue to prevail until 2030. The distortions are of three categories. The market couplings do not fully apply to intra-day and balancing markets, renewables and demand do not participate in the markets as they should, and most importantly the wholesale markets do not make available the full technical capacity of interconnectors. The distortions imply market inefficiencies, as identified in [1]. More specifically, the Net Transfer Capacity (NTC) [15] values as set by the national TSOs underestimate the maximum allowable

[13] A model description of the PRIMES IEM can be found in the PRIMES manual: http://e3modelling.gr/wp-content/uploads/2018/10/The-PRIMES-MODEL-2018.pdf

[14] https://ec.europa.eu/energy/sites/ener/files/documents/ntua_publication_mdi.pdf

[15] The NTC values are unilaterally defined by the TSOs, reflecting a national perspective. Currently, the NTC capacity calculation is decoupled from the allocation of capacities, as the capacity limitations are set before the allocation. This, combined with the fact that the TSOs do not operate in a harmonised manner, leads to a significant limitation of the available transfer capacities. On the contrary, when using the flow-based approach the market becomes aware of potential congestions, without limiting the maximum cross-border capacity; unless this limitation is deemed as a

transfer capacity that is available for allocation to power flows derived by the market coupling. Moreover, a considerably high part of the transactions operate outside the wholesale markets implying must-run obligations for a large part of generation capacity, coming as a result of nominations[16] (bilateral contracts outside the market, both nationally and cross-country). A similar implication comes from the priority dispatch of certain generation technologies, such as variable RES, biomass and cogeneration plants, which operate in priority. Thus, the current practices reduce the extent of market coupling and imply a non-optimal allocation of generation and balancing resources both within a control area[17] and between multiple control areas.

The second case (Option Case 2) represents a completely contrasting situation of the market, which corresponds to the achievement of the full reform ambition of the internal electricity market design. In this context, the market design succeeds removing all priority dispatch rules and nominations. Thus, all generation technologies participate, without exemptions, in all stages of the wholesale markets. Also, almost the entire physical capacity of interconnections becomes available to wholesale market-driven power flows between control areas. This becomes possible as a result of full coupling of all market stages, including the intra-day and the balancing markets, and the effective coordination of the TSOs and a full harmonisation of the system management and control practices, as envisaged by the recast of the directive for the internal market in electricity (COM/2016/0864 final/2[18]). The market design based on the Option Case 2 would allow for a close to optimal allocation of resources within and among the control areas. As a result, cross-border flows would increase in all stages of the markets, compared to Option Case 0, and the overall system costs would decrease. The model-based simulations effectively confirm this postulate and measure that the overall cost savings are considerable and owe to the market integration.

As mentioned in the introduction, the scope of this study is to examine the emerging role of flexibility and storage in a decarbonisation context with increasing shares of variable RES and a focus on the year 2030. The projections in the context of the EUCO scenarios, include investment in power generation capacities, interconnections and storage systems among the endogenous variables of the PRIMES model. The investment projections reflect optimisation of the power system and include smoothing of load variability resulting from demand response. The projected power system conditions prevail in both options simulated namely the distorted and the full internal market cases. The EUCO scenarios include targets for RES until 2030, which imply a

necessary action. The FB approach enables to maximise the social surplus via the optimal allocation of interconnection capacities, complying with safety standards of secure network operation at the same time. It must be noted that in the modelling simulation the full implementation of the TYNDP for the ENTSO-E is assumed and is taken into account. Many of the investments in the TYNDP will lead to the decrease, if not removal, of loop flows and also in the reinforcement of the maximum cross-border capacities.

[16] Nominations is a practice of declaring to the TSO power capacity of certain plants and a specific load, usually defined regarding the time profile and the magnitude, as a package which is taken out of the merit order scheduling performed by the TSO. Often a nomination may also involve part of the capacity of an interconnector, in which case the transfer capacity of the interconnector available for the other operations is reduced

[17] The use of the term “control area” refers to a coherent part of the interconnected system, operated by a single system operator. Some countries, i.e. Germany, may have more than one control areas. This definition is in line with the definition of ENTSO – E available online: https://entsoe.zendesk.com/hc/en-us/articles/215954283-What-is-the-difference-between-a-Control-area-a-Bidding-zone-and-a-Country-in-the-data-views-

[18] This study is based on the Commission proposal of the recast of the directive.

RES share in power generation of the order of 50%, including hydro and biomass. The share of variable RES in power generation does not exceed 40% by 2030 in the EUCO scenario used. Such level of RES deployment is ambitious compared to today's levels but is not too high to imply disrupting management of the power system. The optimal development of new power plants and the expansion of interconnections taking into account the level of RES development in the system until 2030, and therefore, from a modelling perspective, the power system is well prepared to manage RES effectively. The model-based analysis has shown that RES levels above 70-75% may call upon disruptive changes in system management such as massive development of storage systems, and in particular chemical storage systems. In this sense, the EUCO scenario context corresponds to a manageable situation regarding RES that does not require development of novel storage systems. Nevertheless, it must be emphasized that the total storage capacity in the EUCO30 increases from 47 GW in 2018 (only pumped hydro storage) to 59 GW in 2030 (pumped hydro storage and battery storage), which means an increase of 26%. The objective of the simulation is to evaluate the cost impacts of non-removing the current market distortions, despite the optimal evolution of the power system to manage the increased RES effectively.

Typology of storage and flexibility needs

Flexibility in power system operation signifies the ability of the system to respond to both predictable and unpredictable changes in generation and demand in a way to meet reliability standards adequately and avoid curtailments of either load or RES. In a system with high contribution of variable RES, three sorts of variability occur. Firstly, largely unpredictable variations of RES may occur in short or very short time intervals, due to meteorological changes of stochastic nature. Secondly, largely predictable variations of RES occur daily over multi-hour or multi-day timeframes, respectively for solar and wind. Thirdly, extreme meteorological events that may be predictable seldom occur, such as an unusual lack of variable RES over a long period. All three variability cases may challenge the system with respect to reliability.

All three cases call upon resources of the system that are part of the flexibility needs of the system. The flexibility providing resources are reserves that the system monitors. The nature of the flexibility reserves may differ depending on the timeframe of their activation by system management commands. The three cases need resources[19] that feature activation performances corresponding, respectively, to: few minutes, multi-hour or multi-day and, to occasional operation (*Table 2*).

1. The **short-term variability** requires spinning reserve and generally resources with fast response, including flows over interconnections, demand response and storage (with adequate features).
2. The **multi-hour or multi- day variability** requires power resources able to operate in a cyclical way and have high ramping capabilities.
3. The **extreme event variability** requires system reserves that are seldom active as last recourse of the system, such as replacement reserves, chemical or other storage with seasonal possibilities.

[19] Some of the resources presented in Table 2 have not reached yet an adequate level of maturity for providing each type of flexibility services. For example, the research focus on smart grid technologies will enable in the future the deployment of demand response, batteries and other technologies for providing spinning reserves by shedding flexible loads. The reader is referred to section 0 for a detailed presentation of each resource type, their maturity level, technical characteristics and barriers.

Short-term (minutes)	Mid-term (multi-hour or multi-day)	Long-term (occasional)
CCGT, Gas Turbine (GT), Hydro power plants with dam, Interconnectors Pumped storage, Batteries, flywheels Demand response	*(directly)* CCGT Hydro plants with dam Interconnectors *(indirectly)* Batteries, pumped storage, Demand response	Power plants in cold reserve, of any type Peak Devices Chemical Storage CAES

Table 2: Categorisation of flexibility resources based on the activation timeframe

The modelling approach used to assess market design options accompanying the emissions reduction policies until 2030 did not have the simulation resolution to analyse the case of very short-term variability. The simulation included hourly stochastic events, including forecasting errors of meteorological conditions and other random events such as outages. Therefore, the study ignored resources that have minute-to-minute response features, which usually serve frequency and voltage control purposes. The simulation of flexibility reserves able to respond in hourly timeframes are typically those that serve meeting requirements for spinning secondary reserves.
The typology of ancillary services as currently practiced does not identify the multi-hour and multi-day flexibility reserves, as such. On-going studies consider adding to ancillary services a so-called flexibility reserve to address multi-hour and multi-day requirements [17] [18] [19]. The common feature of the corresponding resources is the ability to operate in a cyclical way, i.e. with frequent start-ups and shutdowns, and to feature high ramp-up and ramp-down capabilities.

Short-term flexibility

Short-term flexibility describes deviations (upwards and downwards) between the Day-Ahead and the Real time operation of the system over a timeframe from a few minutes up to half an hour. The deviations owe to the occurrence of meteorological forecasting errors, unpredictable fluctuations of load and system resource outages. Owing to market failures, deviations may also occur when the plant scheduling derived from the energy-only market does not fully anticipate the technical constraints involved in the cyclical operation of power plants. The intra-day and balancing markets improve predictability of events [2] and re-schedule plant operations to manage the deviations, which were unpredicted in the plant scheduling defined the day before. From a systems management perspective, spinning reserves, i.e. Frequency Containment Reserves (FCR) and automatic Frequency Restoration Reserves (aFRR), address these short-term deviations.
The increasing deployment of RES, as expected in the EUCO scenarios, imply an increase in the amount and frequency of imbalances due to forecasting errors, despite the expected progress in the forecasting technology. To address this expectation, the

scenario projections assuming an increase in the size of reserves required by the system management, and in particular regarding the reserves that allow for increased flexibility in addressing short-term variability. However, the FCR is not expected to change by 2030, because it is currently sized on contingency events. It is thus mainly the aFRR that is considered to be impacted by the increasing deployment of RES. As a consequence, in the analysis presented in this section, short-term flexibility needs are assimilated to aFRR needs.

The model-based simulation includes a random generator of events categorized in three groups, namely meteorological forecasting errors, load variability and outages of plants or interconnectors. The simulator calculates the deviations between the outcome of the random events and the plant scheduling derived from the simulation of the day ahead markets and nominations. In the next stage, the model simulates the operation of an intra-day market, which activates resources to address the deviations and at the same time meet the system's requirements for ancillary services. The simulator considers the technical possibilities of the system resources to respond to deviations in a short period and keep spinning reserves as needed for the ancillary services. Thus, the simulator can measure the activation of resources to address short-term variability as a short-term flexibility. In doing so, we assume that the Intra-day market[20] provides short-term flexibility in a cost-effective manner, while respecting technical restrictions of plant operations and the economic interest not to deviate from the Day-Ahead plant scheduling excessively. However, the cost-effectiveness of the intra-day operation depends on the resources that are available[21], which in turn depends on the assumptions on whether market distortions prevail or not in 2030. The distortions obstruct achieving optimality fully.

Figure 2 presents a measurement of the size of short-term flexibility services provided in the Intra-Day Market per resource type at EU28 level in the year 2030. The figure distinguishes two cases, namely the option case 0 that includes the distortions and the option case 2 that assumes complete removal of the distortions.

The results of the model show that gas plants and dispatchable RES[22] are the main sources providing flexibility in the Intra-day. Gas plants (mainly CCGT and some peak devices) cover 38-43% of the short-term flexibility, as these plants are able to operate under automatic generation control (AGC) and also have high ramping rates. Dispatchable RES also cover a significant share of the short-term flexibility needs, ranging from 23% to 40% in the two scenario cases. Hydro power plants with a dam (the largest part of dispatchable RES) have high ramping rates and even though the water resource in the dams is limited, they are suitable for covering short-term imbalances on short (within the hour) timescale.

On the other hand, solid-fired and nuclear plants operate as inflexible units. However, these plants also provide short-term flexibility due to a load following operation, but their contribution is much lower than that of gas plants.

It is worth noticing, that the two option cases differ regarding the part of flexibility covered by the inflexible plants. This part is 34% in option case 0 and 22% in option case 2. It is similarly noticeable that the part covered by gas plants is also lower in option case 2 compared to the option case 0. The removal of distortions favours the contribution of dispatchable RES to address short-term flexibility requirements of the

[20] The reader is referred to Appendix 2 for a detailed presentation of the methodology.

[21] We have assumed that short-term flexibility is covered by resources currently used for providing aFRR in the majority of countries. Energy storage systems (e.g. pumped storage plants, batteries) and demand response are assumed to provide only FCR and multi-hour flexibility, and thus not short-term flexibility assimilated to aFRR..

[22] The term "dispatchable RES" refers to hydro power plants with a dam and plants using biomass, biogas etc. It refers to power plants which are inherently dispatchable without additional options.

system. At the same time, the total amount of these flexibility services is lower in option case 2 than in case option 0.

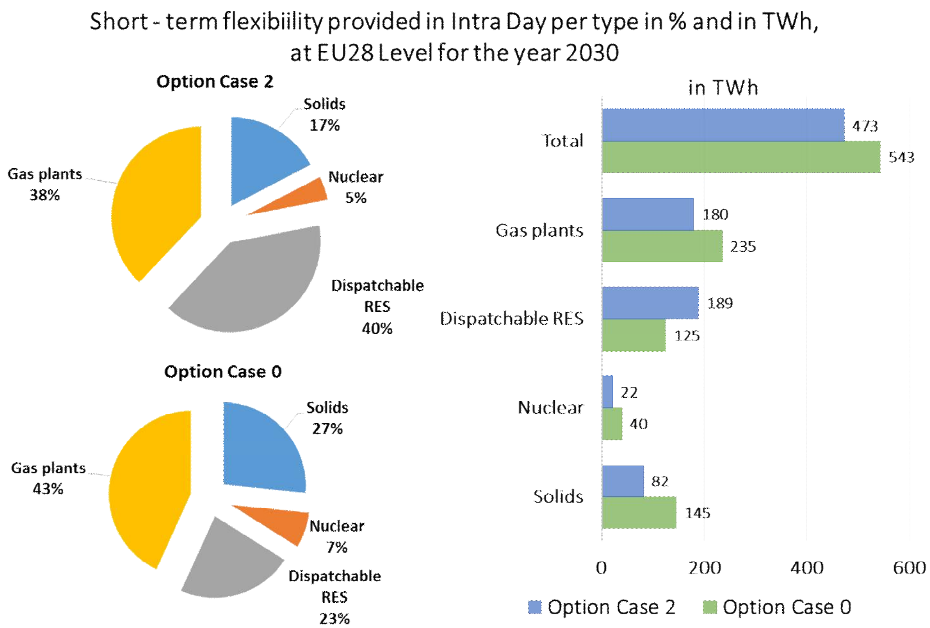

Figure 2: Mix of resources in the supply of flexibility

The decreased short-term flexibility therefore comes because of the implementation of the full coupling of the intraday markets, as assumed in Option Case 2. In the same option case, the assumption of a removal of NTC restrictions and the harmonised cooperation between the TSOs allow for providing the entire physical capacity of interconnectors to the markets (both Day Ahead and Intra Day) for flow-based allocation.

In this sense, the results of the simulation provide evidence that the cost-efficient sharing of balancing and flexibility resources between the control areas in the interconnected system of Europe is better when removing the distortions. The limitation of the size and variety of balancing and flexibility resources within each control area, as implied by the distortions, oblige the system to increase the use of expensive and polluting resources, such as the fossil fuel plants. The removal of distortions, allow for a larger sharing of the resources, which provide increased opportunities for the systems to use the (dispatchable) RES and the flows over interconnections instead of using the fossil fuel and nuclear plants for balancing. Thus, the increased optimality achieved in option case 2 compared to option case 0 brings obvious benefits regarding the costs and the emissions. Our sensitivity analysis, consisting in evaluating the importance of each type of distortion for achieving the optimality, has shown that the most critical is the exploitation of interconnection to the maximum technical possibilities. Deriving power flows over interconnectors from the sequence of markets (i.e. from all stages, namely day-ahead, intra-day and balancing) without obstruction from unnecessary restrictions is of utmost importance for meeting short-term flexibility requirements cost-efficiently. The cost savings derive both from the reduction of total needs for flexibility services and the reduction of the average variable cost of the resources used to meet the short-term flexibility. The cost savings in option case 2 from the option case 0 are, thus, of the order of 35%, in 2030. Total savings in short-term flexibility needs, measured physically, amounts to 13% between the two option cases.

In the following, we present the simulation results aggregated by groups of countries with geographic proximity. Each country group includes bordering countries, which have similar power mix characteristics and apply market coupling with limited obstructions due to interconnection congestion (e.g. Baltic countries, Germany & Austria, Nordics). *Table 3* shows the assumed country groups.

Country Group	Countries
Baltic	Estonia, Latvia, Lithuania
BENELUX	Belgium, Luxembourg, Netherlands
Central East	Czech, Slovak Republic, Hungary, Poland
France	France
Germany & Austria	Austria, Germany
Iberian Peninsula	Portugal, Spain
Nordics	Denmark, Finland, Sweden
South	Bulgaria, Cyprus, Croatia, Greece, Italy, Malta, Romania, Slovenia
UK & Ireland	Ireland, UK

Table 3: Mapping of country group names and Member States

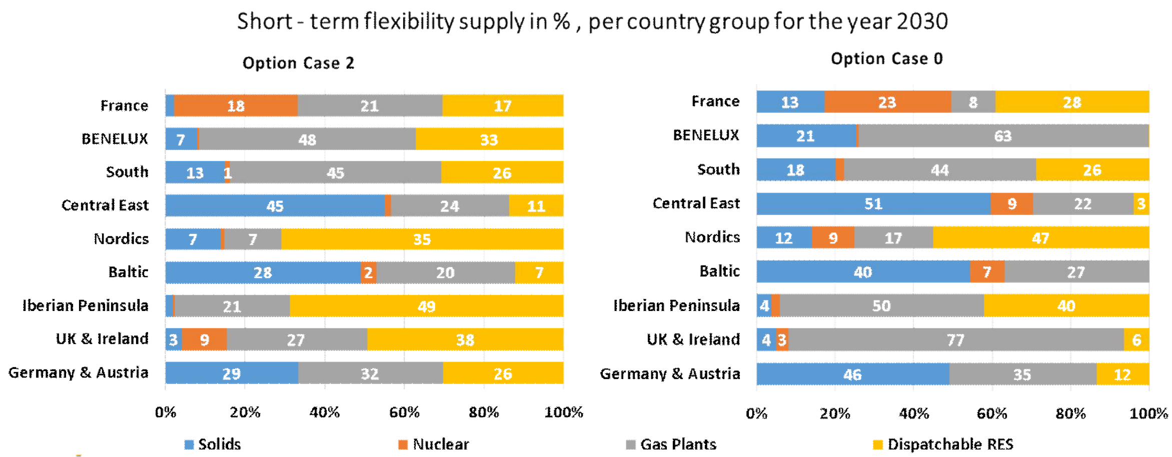

Figure 3: Shares of resources in the supply of flexibility

Figure 3 presents the way of meeting short-term flexibility in each group of countries separately. It can be seen that the comments made for the results at the EU28 level are valid also for the large majority of country groups, with few exceptions. Gas plants and dispatchable RES hold the largest shares in the flexibility supply mix, except in Baltics and Central East. In Central East countries, solid-firing plants dominate electricity generation from fossil fuels, and thus participate in short-term flexibility supply more than in other countries. A similar situation applies to France for the nuclear plants. Among the Baltic countries, shale oil plants categorised in solid-firing plants dominate the Estonian power fleet and thus cover the majority of the flexibility requirements.

The removal of distortions, included in option case 2, implies a significant increase in the part of flexibility needs covered by dispatchable RES in all countries, except in the Nordic area. The increase in the use of interconnections implies higher exports of hydro-based balancing from the Nordic area to other areas, which imply lower availability of hydro within the Nordic area, hence a lower contribution of RES to the balancing in this control area.

Indeed, as *Figure 4* shows, the assumption of Option case 2 favours an unobstructed flow-based allocation of the entire interconnection capacity, thus driving a significant increase in the cross-border exchanges for managing the flexibility and balancing requirements. In fact, the sharing of resources under the assumption of the perfect implementation of the market design initiative (Option Case 2) implies an almost doubling of power exchanges between areas within the intra-day transactions, compared to the option Case 0, which assumes continuation of market distortions.

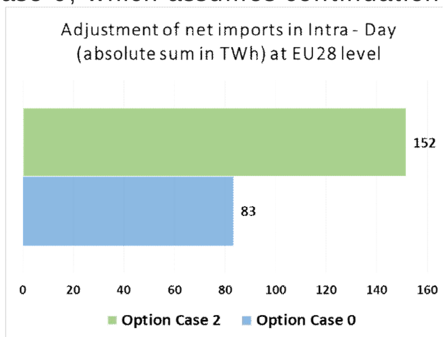

Figure 4: Sum of deviations attributed to cross-border flows in intraday

The increase in short-term flexibility from dispatchable RES under the assumptions of Option Case 2, compared to Option Case 0, also relates to the assumption that the RES participate in the intra-day and balancing markets. In fact, solar thermal, biomass plants and even variable RES plants participate in the balancing to provide upward adjustments in most cases, and thus complement the balancing role of hydro. Therefore, coal and nuclear plants provide lower amounts of short-term flexibility in option case 2 (compared to option case 0). However, the decrease is less significant for the gas plants. The flexibility provided by solid-fired and nuclear plants decreases by 43-45%, while for gas plants the decrease is only 23% approximately. This is due to the operating features of the gas plants that favour cyclical operation, in contrast to inflexible plants.

Mid-term (or multi-hour) flexibility

The concept of multi-hour (or mid-term) flexibility describes the variation of plant operation on a multi-hour timescale within a day or over a few days. The term multi-hour flexibility encompasses upward and downward flexibility. For analysis purposes, we assume that the forecasting of the multi-hour or multi-day variation of the generation by RES is perfect. However, the system needs to schedule adequate dispatchable resources (including demand response and flows over interconnectors) to meet the variation of net load (i.e. load minus variable RES) in a way of avoiding excessive curtailment of RES or curtailment of demand. In other words, the long-term flexibility needs implied by the deployment of RES is independent of stochasticity. In this sense, we disengage the term of multi-hour flexibility from the effect of forecasting errors, which were necessary to take into account to analyse the short-term flexibility category as described in the previous section. Thus, we associate multi-hour flexibility with predictable variability. Based on the modelling of system simulation, we present in this section, a measurement of requirements for flexibility and the mix of resources that ensure the supply of flexibility.

From a modelling perspective, we calculate the requirements for multi-hour flexibility as the sum of upward or downward variations of the net load (load minus variable RES) caused by variable renewable generation. We also add to flexibility requirements the variations of power generation from dispatchable resources that are in the opposite direction of the variation of net load. We similarly add the variations of the flows over interconnections to the flexibility requirements when the flows are in the opposite direction of the variation of net load.

The multi-hour and multi-day variations due to variable RES require a cyclical operation of dispatchable generation sources, which intensifies as the amount of variable RES increases. This is particularly evident for solar PV energy, the variation of which implies that the net load takes the scheme of a duck in a 24-hour timeframe. To meet peaking net load after sunset, the TSO needs to foresee scheduling of dispatchable resources some hours before the sunset, although they are probably not necessary in the mid-day when sun shines. Similarly, the TSO may need to shut down dispatchable resources in the night, when net load is at low levels, to avoid over-generation concerns related to inflexible power plants, such as nuclear plants for example.

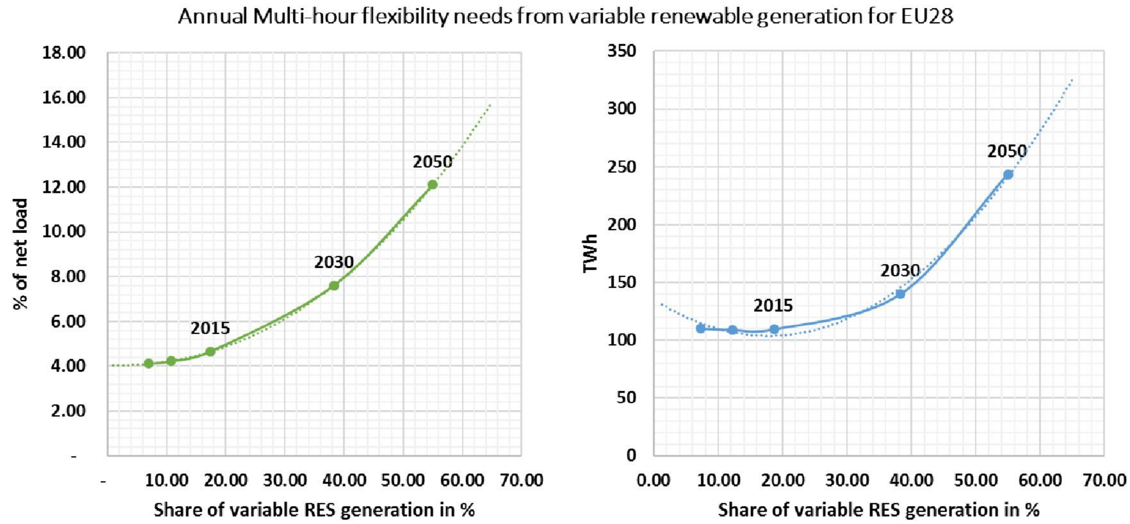

Figure 5: Annual multi-hour flexibility needs in EU28

Figure 5 relates the annual multi-hour flexibility requirements measured as a percentage of net load and in TWh to the share of variable RES in total generation. The figure uses the simulations based on the model applied for several years until 2050 in the context of the EUCO scenario. The figure reports numbers for the EU28. The measurements based on the simulation for the year 2030 estimate that the multi-hour flexibility requirements, caused by variable RES generation, increases by 3pp in terms of percentage of net load and 28% in absolute values in 2030, compared to the 2015 levels, and more than doubles in 2050. By that year, variable RES cover almost 55% of the electricity generation. The curve shown in the figure has a non-linearly increasing slope, implying that multi-hour flexibility coverage may rise concerns beyond certain levels of variable RES. The projections of the EUCO scenario involve for the year 2030 a share of variable RES that is at a moderate level, despite the considerable RES deployment effort until then. The implied increase in multi-hour flexibility requirements is also moderate in 2030 for the projected share of variable RES. Nonetheless, although this results hold true for the EU as a whole, the projections by country may imply that certain countries may face multi-hour flexibility needs well above the EU average, and thus concerns may arise in these countries regarding the pat of flexibility resources in the system. The results provided evidence for this concern in southern European countries that deploy primarily solar PV among the variable RES. The deployment of wind and in particular wind offshore is of lower concern regarding the multi-hour flexibility requirements.
The results confirm the conventional wisdom that renewables are the main drives of the increase in flexibility requirements, as the deviations of the net load, i.e. the deviations caused by the variable output of renewables, represent in both Option Cases the largest share (above half of the total). The hourly variations due to power plants and interconnections are deviations of the day-ahead schedule from the real-time dispatching that go to the opposite direction of the variation of net load, according to the results of model-based simulation and the random generation of events. These deviations relate to the need of cyclical operation of flexible plants to

manage multi-hour flexibility and the possible difficulty of dispatching the minimum technical power of inflexible plants at times of low net load. In real time operation the system strictly respects the technical constraints of operation of the plants and at the same manages their production level to get the required reserves in the form of ancillary services. The plant scheduling resulting from the coupled day-ahead markets do not fully respect the complex operation and scheduling in real time. The differences may cause variation of some plants in the opposite direction than variation of net load during the intra-day balancing. The graphic below includes such variations, and attributes them to plants and interconnections. They are, in general, small in magnitude, especially when disaggregated by type of plant, compared to the flexibility requirements attributed to variation of net load, which in turn depends on variation of variable renewables.

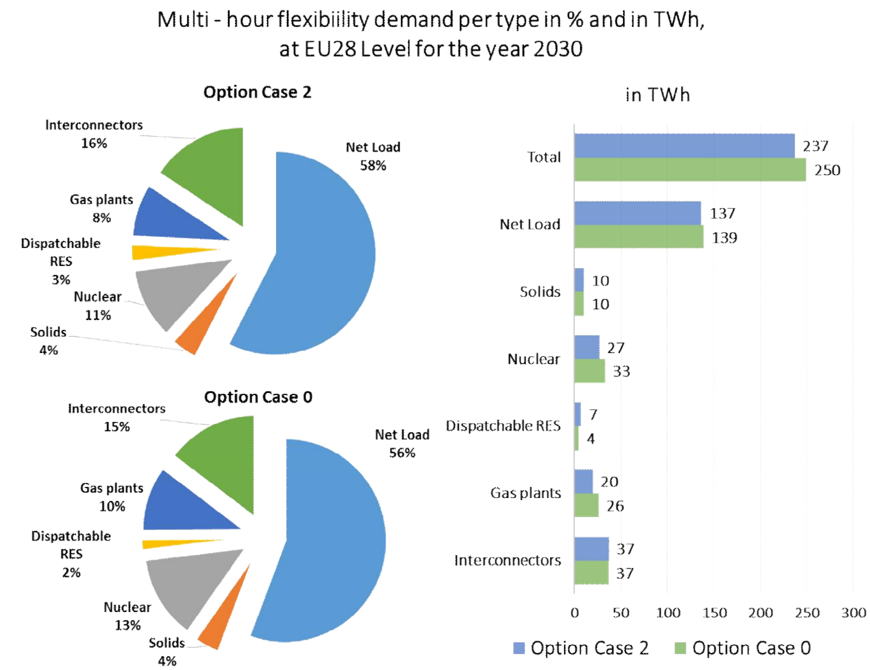

Figure 6: Requirements of flexibility decomposed by origin

The flexibility requirements attributed only to variations of the operation of dispatchable plants represents 27 to 29% of the total requirements of flexibility, with nuclear holding the largest share among the plant types. The variations of net load driven by the variable RES imply load following variation of the operation of inflexible plants and in particular those that operate as base-load ones, such as nuclear plants. It is less of a problem for coal plants because the increase in the ETS carbon prices in the EUCO scenario context imply that coal plants are low both in terms of total operating capacity and operation duration.

The gas plants are those that primarily provide the ramping services to meet flexibility requirements and thus deviate in real time operation from day-ahead scheduling, in a way to be able operating in a cyclical manner as the system requires. This explains that the variations of gas plant operation have also a non-negligible share in total flexibility requirements. In fact, the gas plants provide the majority of ancillary services; thus, they may withhold a part of their capacity for the provision of upward reserves or they may increase their output level above technical minimum output levels to provide downward reserves. This may imply sometimes deviations of the gas plants' output level in the opposite variation of net load because of the multi-hour cyclical scheduling to comply with system requirements. In such cases, the variation of generation of gas plants cause additional requirements for flexibility.

The dispatchable RES, notably hydro plants with a dam, usually operate as “peak shavers”, thus contributing to smoothing of the net load curve. In this sense, the dispatchable RES reduce flexibility requirements and is part of the supply of flexibility.

The flows over interconnectors also cause an increase in requirements for flexibility at a national level. The cross-border flows are responsible for 15 to 16% of total flexibility requirements. The reasons are twofold. Apart from the DC lines, which are dispatchable, the flows over the AC interconnectors are subject to Kirchhoff’s laws, and thus loop flows may occur involving flows that variate in the opposite direction of net load causing additional requirements for flexibility. The second explanation, and the most important one, is the fact that some countries “export” flexibility to neighbouring ones. For the exporting country, this service is accounted in the flexibility requirements, while for the importing country it is flexibility supply. As the imports/exports are flows, generated in one country and transmitted to another, it is reasonable to expect that when the cross-border exchanges increase, driven by the market integration, the flows representing flexibility requirements also increase and imply an increase in the flexibility supply. In other words, higher the cross-border flows higher the trade of flexibility services between control-areas.

A comparison of the two Option Cases regarding the multi-hour flexibility measurement corroborates the view that the implementation of the internal market increases exchange of flexibility cross-border, which can be seen as a sharing of flexibility resources. In Option Case 2, the removal of the currently existing market distortions imply higher availability of interconnection capacity to the markets. Consequently, the multi-hour flexibility requirements at a national level decrease by 5% on average, compared to the “business as usual” Option Case 0. Due to the increase of cross border trade in Option Case 2, the flexibility requirements due to cross-border flows increases because of the increased sharing of flexibility resources. At the same time, the flexibility requirements due to the variation of gas and nuclear plant operation decrease. The elimination of nominations and the increase in available interconnection capacities allows for a smoother operating scheduling of these resources, which decreases the variations in the opposite direction of the variation of net load. In total. The simulation results show reduction of the needs for flexibility, on average, when cross-border flows increase.

The flexibility requirements due to the variations of the net load, because of the variation of stochastic RES, slightly decrease in option case 2 compared to option case 0. The removal of priority dispatch of variable RES in option case 2 increases the occurrence of economic curtailment of RES compared to the option case 0. In both cases technical curtailment may also occur, but the difference concerns economic curtailment. More specifically, at times when RES generation is high (e.g. mid-day when solar PV achieves the highest utilisation rates) if RES have priority dispatch (Option Case 0) the model applies a curtailment penalty, and thus some power plants have to shut down, so as to avoid the curtailment of RES. In later time intervals, when RES generation decreases (e.g. at night when solar PV has zero utilisation factor), these plants have to start-up in order to fill the gap created by the lower output level of RES generation. This dispatching schedule entails high cost due to start-up and a more frequent occurrence of generation variation in the opposite direction of net-load variation. In contrast, the economic curtailment of RES (assumed in case option 2) costs less in terms of the objective function of the model and thus keeping power plants at their technical minimum levels when net load is low is more frequent. In this case, the occurrence of generation variation in the opposite direction of load variation is less frequent.

The main features of the results analysed for the EU taken as a whole, hold true when looking at the flexibility requirements by origin at a country group level (*Figure 7*). The variations of the net load, due to the variable RES, represent by far the largest part of flexibility requirements in all country groups. The size of flexibility requirements associated to net-load variation presents a positive correlation with the share of variable RES in total generation. The cases of the Iberian Peninsula and Germany & Austria represent the highest flexibility requirements and the highest RES shares. In France, however, the part of flexibility requirements attributed to the operation of nuclear plants is significant, having a share ranging from 39 to 44%. The French nuclear plant fleet generates and exports large amounts of electricity, following a base load profile due to their low variable costs, rather than following the fluctuations of net load. Thus, the cases of nuclear generation variation in the opposite direction the variation of net-load occurs more frequently, than in other country groups.

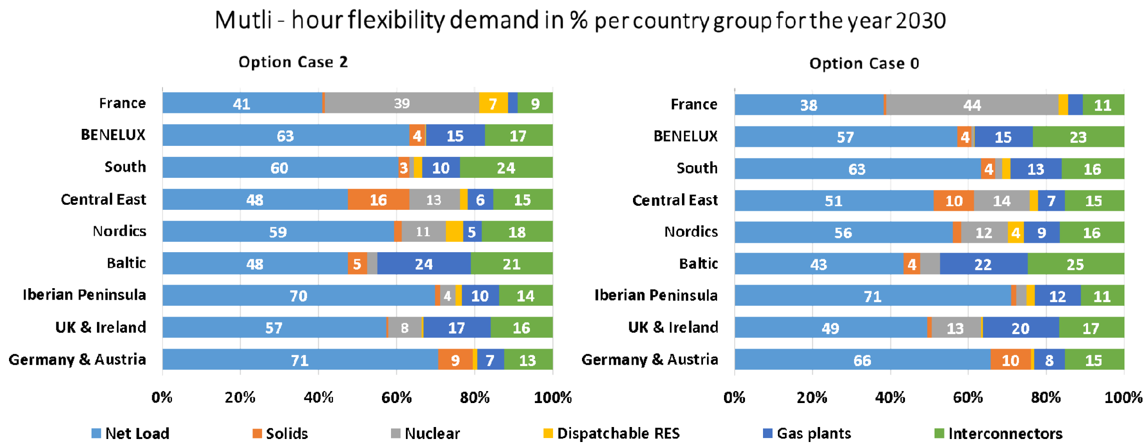

Figure 7: Multi-hour flexibility requirements by origin for each country group

Having discussed the drivers of flexibility requirements, the next part focuses on analysing the resources covering the flexibility needs. According to the model simulations (*Figure 8*), the system employs several resources to cover flexibility requirements. Gas plants, interconnectors and dispatchable RES are, in this order, the main flexibility supplying resources, representing over 68% of the total flexibility needs in both Option Cases. Energy storage systems and demand response and nuclear plants come next, covering 15-16% and 12-13% of the flexibility requirements, respectively. The share of solids-fired plants is only 2 to 4%, being the lowest among all resources.

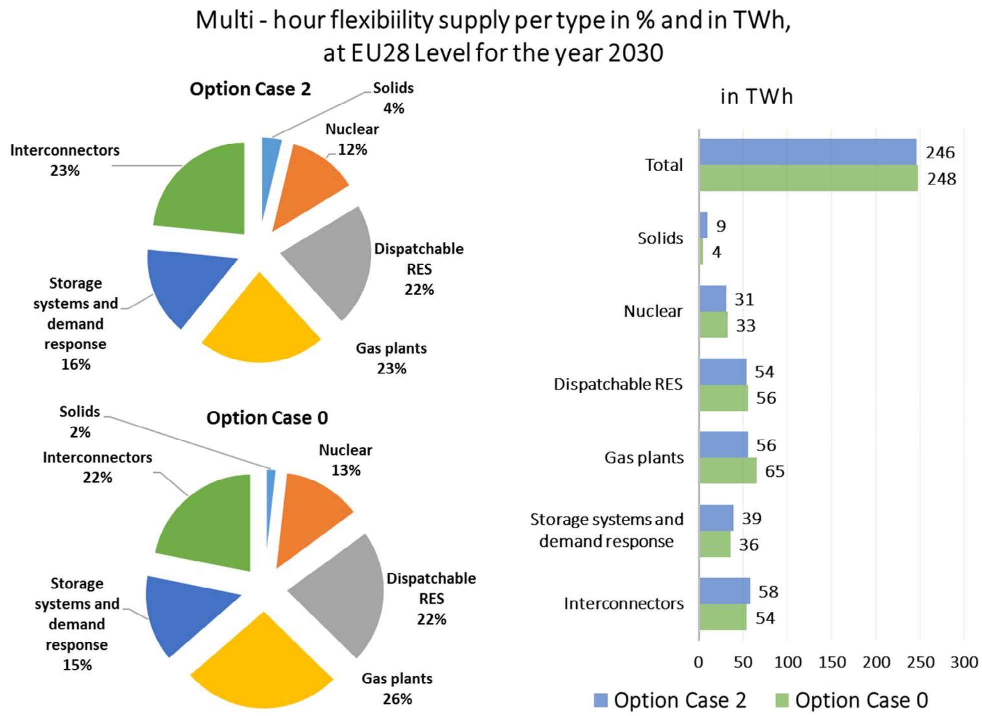

Figure 8: Supply of multi-hour flexibility by origin

Figure 8 shows the contribution of the resources to the coverage of flexibility requirements separately for each group of countries[23]. The mix of resources differs by group of countries, however in most groups gas plants and interconnectors cover large shares. The same applies to storage systems, demand response and dispatchable RES in the country groups that have such resources.

The groups Southern countries and UK & Ireland depend heavily on the flexibility provided by gas plants. The hydraulic resources located in the Iberian Peninsula cover above one third of multi-hour flexibility needs. The results show that the ramping of nuclear plants, although somehow limited, is an important contributor to meeting flexibility in France, covering 40% of the multi-hour flexibility needs. Although in percentage terms this may seem quite high, it represents only 6% of the total generation of nuclear plants, as shown in *Figure 9*. Germany & Austria, along with Nordic countries have a more balanced mix of resources providing flexibility to the system, thanks to the diversification of resources in these countries and the relatively high capacity of interconnection with neighbouring countries. In contrast, the Baltic and Central East countries are likely to depend heavily on cross-border exchanges for covering flexibility needs, as the dominating solid-firing capacity is quite inflexible. On the other hand, Benelux countries primarily employ gas plants, interconnectors and storage systems to cover flexibility needs, as they lack hydropower reservoirs.

[23] As mentioned in the introduction of this chapter, the updated modelling exercise undertaken for the “Clean Planet for All” Communication (2018), includes revised techno-economic assumptions, which show significantly lower costs for many technologies incl. RES technologies and batteries. In the updated scenario exercise the contribution of storage systems is projected to a more prominent role in the supply of multi-hour flexibility. This is caused by the more significant penetration of batteries projected in these scenarios thanks to the faster decline in costs as well as the higher maturity of the technology assumed in this exercise.

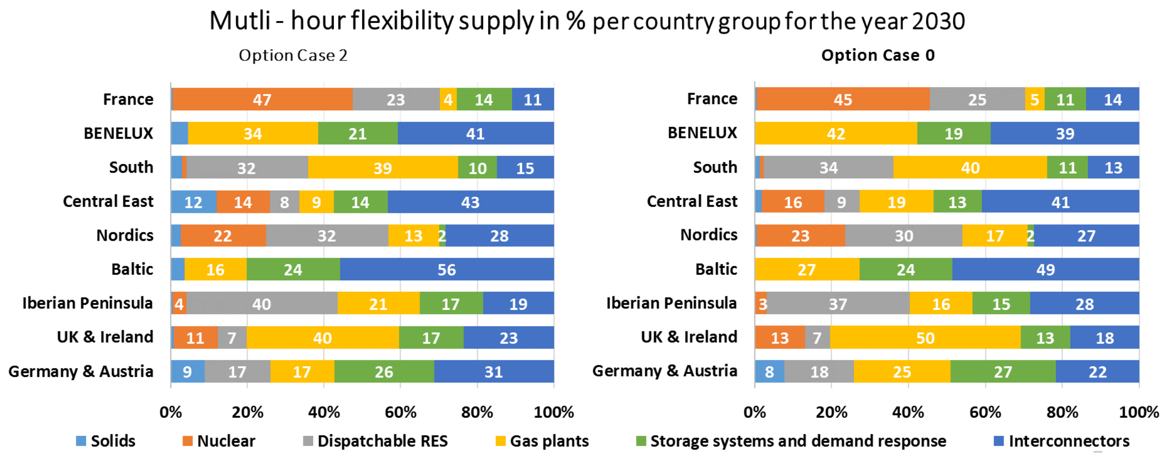

Figure 9: Supply of multi-hour flexibility by origin for each country group

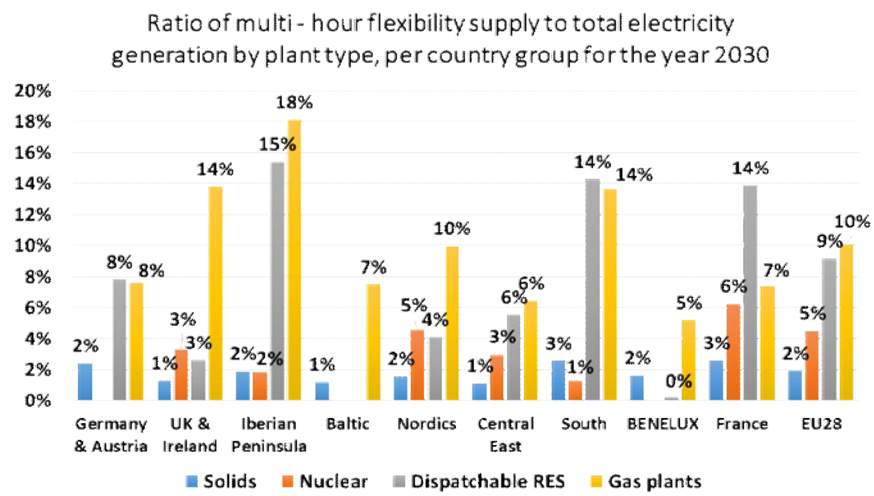

Figure 10: Part of total generation serving flexibility per resource type and per country group (average of the two Option Cases)

Although the flexibility supply mix differs across the groups of countries, the amount of flexibility provision as a share of total generation differs less (*Figure 10*). A high share of flexibility provision within total generation of a power resource indicates its importance in the coverage of flexibility requirements. The results showed that 9 to 10% of the electricity generation from gas plants and similarly of dispatchable RES serve flexibility purposes. The same share is much lower for nuclear and solid-fired plants (2-5%).

The comparison of results between the two Option Cases at the EU28 level shows that flexibility supplied by interconnectors and energy storage plants increases in Option Case 2, compared to Option Case 0, by 6% and 8% respectively. The increased availability of interconnection capacities to the markets, as assumed in Option Case 2, drives a higher role of cross-border flows for the coverage of flexibility needs. The reforms of the internal market enabling the participation of demand response allows for an additional contribution of storage to flexibility coverage. The smoother operation of inflexible power plants, thanks to the better coordination of plant scheduling in Option Case 2 (due to the higher interconnection flows) implies a lower contribution of nuclear and solids plants to the coverage of flexibility needs.

As mentioned above, a power resource may cause an increase in flexibility requirements when its operation variates in the opposite direction of the variation of net load. The same resource may also contribute to the coverage of flexibility requirements when operates in a load following manner, with respect to the variations of net load. Therefore, we can calculate the imbalance of flexibility supply and demand by type of power resource (*Figure 11*).

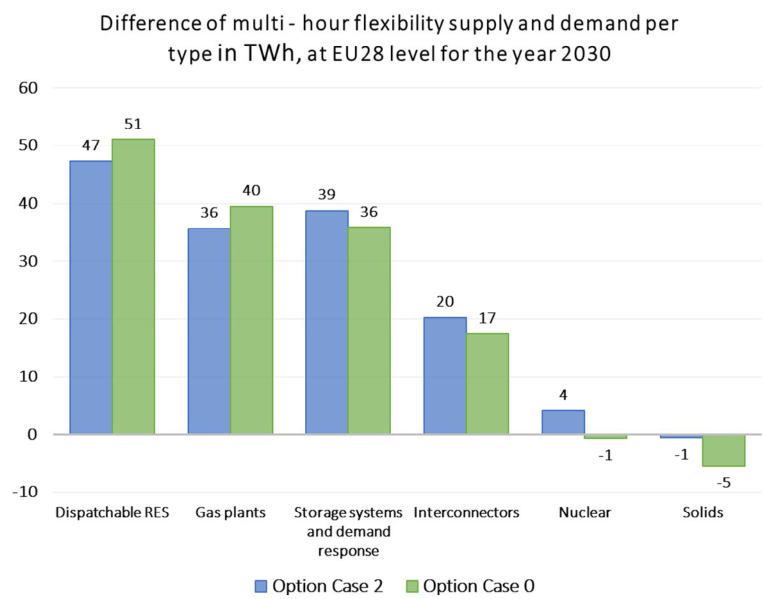

Figure 11: Imbalance between flexibility supply and demand by type of resource

As expected, the dispatchable RES, notably the hydro plants[24] with a dam, supply flexibility much more than the flexibility needs they cause. The same applies to storage systems and gas plants. This verifies their role as flexibility providers in the system. Interconnectors are also significant net providers of flexibility. However. the net amount of flexibility from cross-border flows is lower than that from the national flexible resources. This is due to the fact that exporting flexibility implies lower flexibility resources for the exporter, because there is no possibility, by assumption, to vary net imports or exports of flexibility at the EU level, taken as a whole[25].
The net provision of flexibility by the inflexible plants, such as nuclear and solids, is very small, as expected, and in the case of the latter it is negative, meaning that solids plants cause flexibility more than they provide.

Factors explaining the differences in flexibility needs between the countries

As one of the main goals of this study was the measurement of flexibility needs in the context of the EUCO scenario, the figure below summarises this measurement by

[24] The simulations consider average hydrological conditions calculated on the basis of long time-series quantified using Eurostat data reporting the generation of hydro power plants. We do not introduce stochasticity of water availability in the model because of the complexity. The stochasticity of water availability expands over multiple year timeframes which implies a considerable computer time burden to the model.
[25] According to the assumption of the EU energy system modelling, EU countries are assumed to succeed on achieving adequacy of electricity, meaning net zero imports of electricity at EU28 level.

showing total flexibility requirements as a ratio over total electricity generation. The figure shows the results for the Option Case 2 because this option includes the most economically optimal operation of the market in the EUCO context. The needs for short and multi-hour flexibility represent 21% of total electricity generation in 2030 in the EU28. The same figure ranges between 11.6% and 31.5% among the groups of countries groups (*Figure 12*).

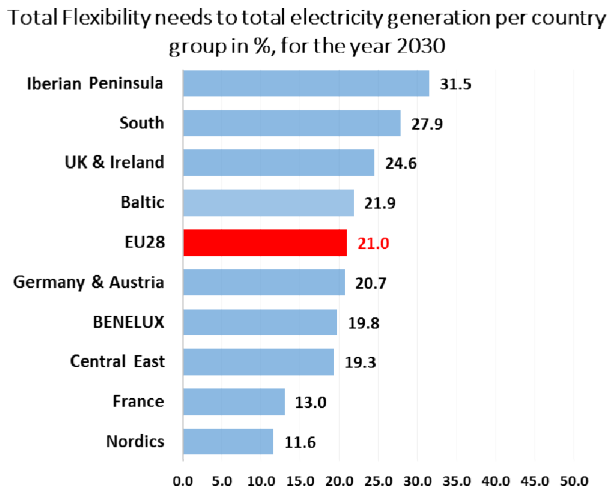

Figure 12: Flexibility requirements compared to total electricity generation per country group

The Iberian Peninsula and the Southern countries have the highest levels of flexibility needs, while France and the Nordic countries have the lowest. The degree of deployment of variable renewables obviously drives up flexibility needs. But also, the share of inflexible power plants in the mix influences the level of flexibility requirements. A country with significant penetration of variable renewables combined with high shares of inflexible plants, has higher flexibility needs, compared to a country with the same or even higher share of variable RES, but with high generation shares from hydro plants with a dam, interconnections and gas-based capacities.
Figure 12 summarises by group of countries the figures for factors influencing the size of flexibility requirements. The Iberian Peninsula requires the highest levels of flexibility relative to total generation because of the high share of RES. The abundance of hydro-resources helps to moderate the amount of flexibility needs but the limited capacity of interconnections with other areas has an upward effect on flexibility needs. The rest of southern countries have also high needs for flexibility because of the high RES shares, but also have significant hydro resources and interconnections which when fully exploited help to moderate flexibility needs. In the case of United Kingdom and Ireland, the high shares of renewables (mostly wind), the significant share of nuclear plants leads, the lack of hydro and the limited interconnections imply high levels of flexibility needs. The Baltic countries have high flexibility needs not because of the RES shares but because of lack of other resources.

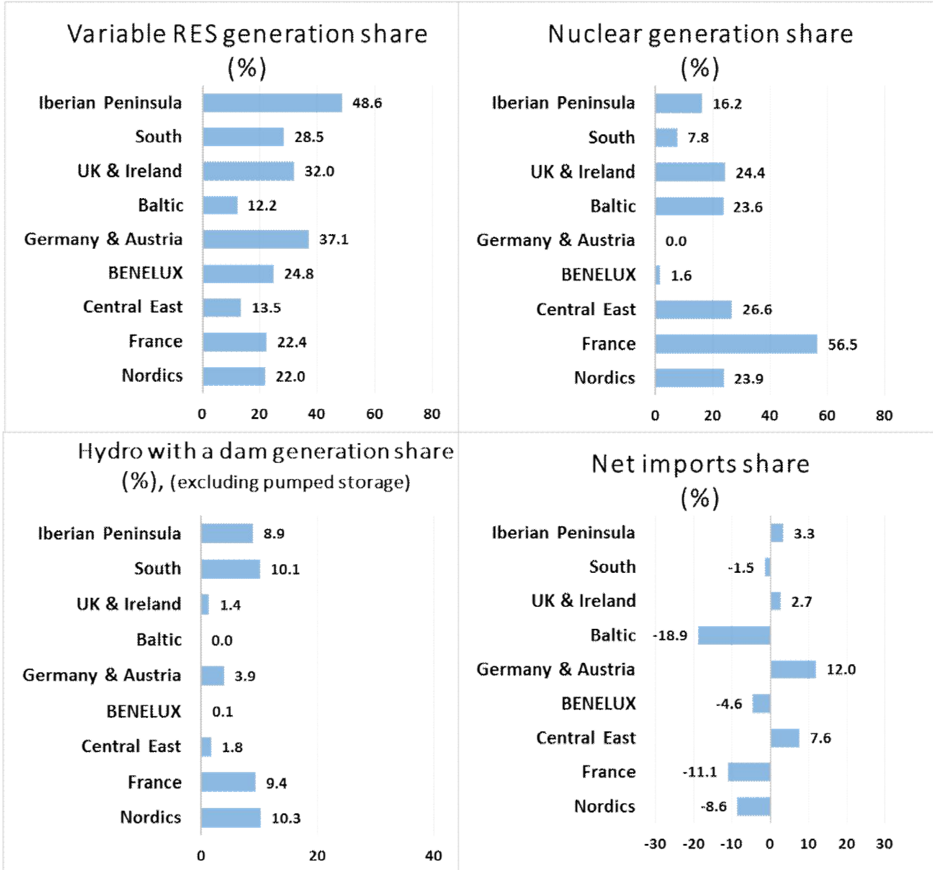

Figure 13: Summary of factors by country-group that have different effects on flexibility requirements

Three regions –Germany and Austria, BENELUX and the Central East region –have very similar flexibility requirements of around 19%-20% in 2030 in the EUCO scenario analysed; however, the reasons for the flexibility requirements are very different.
Germany and Austria, have the second largest variable RES generation share among the country groups (37.1%), however the nuclear phase out in Germany and the high net imports reduce the flexibility needs. The geographic location at the centre of Europe, enables Germany and Austria to use the flows over interconnectors as a balancing resource, limiting thus the need for additional flexibility. Compared to the case of the Iberian Peninsula, and UK and Ireland Germany and Austria are found to need lower amounts of flexibility, nonetheless equal to the one fifth of their total electricity generation. The BENELUX region has a significantly lower share of variable RES. However, the flexibility requirements remain high due to the lack of hydro plants and the existence of nuclear reactors. Comparable flexibility needs were found also in the case of the Central East country group, although the variable RES share is relatively low. The high share of nuclear and coal generation combined with low shares of hydro with a dam explains the size of the flexibility needs in this group of countries.
France and Nordic countries present the lowest needs for flexibility relative to the size of total generation among all country groups. These countries have among the lowest shares of variable RES, and at the same time have high shares of nuclear and hydro resources. In particular, the hydro resources are of great importance for the balancing services and the management of flexibility.

Conclusions

The present study has modelled short and mid-term flexibility from two perspectives: the origins of flexibility requirements and the provision of flexibility services. The context is the scenario EUCO of the “Clean Energy for All Europeans” which foresees a significant increase of variable RES until 2030 that nonetheless reach a level that is manageable from a today’s perspective. The analysis employs the detailed simulator PRIMES-IEM that applies on the entire European interconnected system and represents the sequence of markets, from day-ahead to intra-day and balancing. The simulations assume random events that take place after the day-head scheduling and cause deviations that the system has to balance. The origin of stochasticity refers the meteorology forecasting errors, to demand variations and to outages.

The study measures flexibility using the model-based simulations for the year 2030. The study defines flexibility requirements as the sum of net load variations, which is due to the variable RES, and the sum of opposite variations of power generation units and interconnection flows, which are due to technical constraints of system and plant operation and to possible differences between day ahead and real time system operation.

The measurement of flexibility requirements confirms a clear dependence on the deployment of variable RES and finds a nonlinearly increasing effect of the increase in the share of variable RES on the total amount of flexibility requirements. The deviations regarding the variation of power plants and cross-border flows as causes of flexibility requirements are of less importance in volume terms in comparison to the effects of variable RES. The amount of flexibility requirements projected for 2030 is manageable on the EU as a whole using conventional resources. This is because the level of RES share is relatively moderate in 2030. Sensitivity analysis based on the same model showed that the increase of the RES share, for example towards the longer term, could raise concerns regarding the sufficiency of conventional resources to manage flexibility effectively, and so additional resources would be needed, for example by deploying non-conventional electricity storage. However, the flexibility coverage concerns may be considered as important already in 2030 in some countries, and in particular in the south of Europe due to the deployment of solar PV.

The deployment of wind energy, as in the North, raises different concerns than solar PV regarding flexibility. Wind variability calls upon significant resources with fast response times, whereas the solar irradiation periodicity calls upon resources with possibility of cyclical operation over a multi-hour time framework. Long-term reserves to manage rare situations with lack of both RES are outside the scope of flexibility, as defined in this study, and may call upon strategic reserves.

The study focused on two timeframes regarding flexibility. Firstly on short-term variability occurring in few minutes time intervals. The model applies stochasticity to represent such variability and considers power resources with fast time response and spinning availability as suitable for covering the requirements. Gas plants, hydropower and interconnectors are among the resources covering this need adequately. The increase of variable RES causing the short-term variability implies an increase of the amount of power to have in spinning reserve. This further implies that significant deviations may arise between the scheduling resulting from the day-ahead market and the intra-day and balancing operation. The deviations are likely to drive additional flexibility requirements of non-negligible size. The other timeframe regards multi-hour flexibility caused by the periodicity of RES availability, notably related to solar PV. For analytical purposes, the modelling handles this periodicity as predictable. Resources with multi-hour cyclical operation are necessary to manage the multi-hour flexibility, notably the gas plants, hydropower with reservoir, and interconnections. The storage and demand-response resources are important to reduce the amount of total needs for flexibility but they cannot provide ramping services on a perpetual basis to the system, due to the energy constraints (maximum charge/discharge cycles). Over-generation threats are of important concern in the multi-hour framework regarding inflexible power plants at times of low net load. This is a less important issue for coal plants because their capacity shrinks in the projections to the rising ETS carbon prices. It is however important for nuclear power plants. To manage the rising multi-hour flexibility requirements and at the same time cover a significant part of the ancillary services, the gas plants will have to accentuate the cyclical operation involving faster ramping and more frequent start-ups and shutdowns than usual. This also causes an increase of deviations between the commercial purposes of gas plants and their operation for the provision of system services, including the coverage of multi-hour flexibility. Which market arrangements may address possible missing money issues arising for the gas plants in this context is outside the scope of this study.

The integration of the internal market and the removal of market distortions assumed to characterise the Option Case 2 is of great importance for cost-effective management of the increasing flexibility requirements driven by the increase in variable RES. This has been a clear result of the model-based analysis. The abolishment of restrictions on interconnection capacities and the increase in the market-driven allocation of cross-border flows in all stages of the sequential markets allows for the sharing of flexibility resources among the control areas in Europe, which implies significant cost savings. The limited cross border flows in addressing flexibility in the context of the Option Case 0 implies a stressing of national flexibility resources, obstructs the smooth operation of inflexible power plants and increases the occurrence of curtailments. The rest of the reforms included in the Option Case 2 are also important for addressing flexibility. The demand response, the participation of RES in the balancing markets and the removal of nominations increase the resources that can meet flexibility requirements and allow for an effective management of the resources and a harmonisation of the plant scheduling deriving from the day ahead and balancing markets. These are also important for the cost-efficiency in providing the flexibility services to the system.

The model results confirmed that gas plants, dispatchable RES and energy storage systems and demand-response are in this order the largest contributors to the coverage of flexibility requirements. Another important resource providing flexibility is the use of interconnectors if the market does not limit their capacity and their usage within the markets. The sharing of balancing resources via interconnectors smoothens the pattern of the net load, enables a more optimal allocation of resources and can lead to the reduction of total flexibility needs. As expected, nuclear and solids-fired plants have a minimal contribution to covering flexibility needs.

Impact of the transmission system

Introduction

National transmission systems can currently cause major bottlenecks, leading to curtailment of renewable energy sources and high redispatch costs. The traditional way to alleviate bottlenecks is grid reinforcement. An alternative to grid reinforcement could be the integration of storage to smoothen the renewable energy sources in time. Indeed, these congestions occur when the generation from renewable energy sources is high, while the average capacity factor of PV and of wind in Europe is moderate (e.g. from 10 to 20% for PV, 30 to 40% for onshore wind, 40 to 50% for offshore wind). The purpose of this section is to explore through two specific cases the relevance of using storage as an alternative to transmission grid reinforcement.

Case study 1: Belgium

The EUCO30 scenario expects a significant increase of the offshore wind capacity installed in Belgium in 2030, compared to 2020. However, the existing transmission capacity between the shore and Belgium’s interior (Stevin axis) will be fully used by

2020. A second transmission corridor, a new Stevin – Avelgem – Courcelles corridor will thus be needed to evacuate the additional offshore wind energy, as shown in *Figure 14*. Alternatively, 2 GW of storage could be installed at Stevin to smoothen the power to be evacuated to the Belgium's interior. However, the wind velocity tends to change slowly rather that abruptly with typical diurnal cycles, which means that the required ratio energy to power should be around 12 hours. Using the costs given in section 0, the storage solution would lead to a total cost of several billions of €, while the second transmission corridor would lead to a total cost of less than 1 billion of €, according to the ENTSO-E TYNDP 2018. As such, the storage solution does not appear attractive, except if public opposition to new transmission projects in Belgium hampers the concretization of that second transmission corridor.

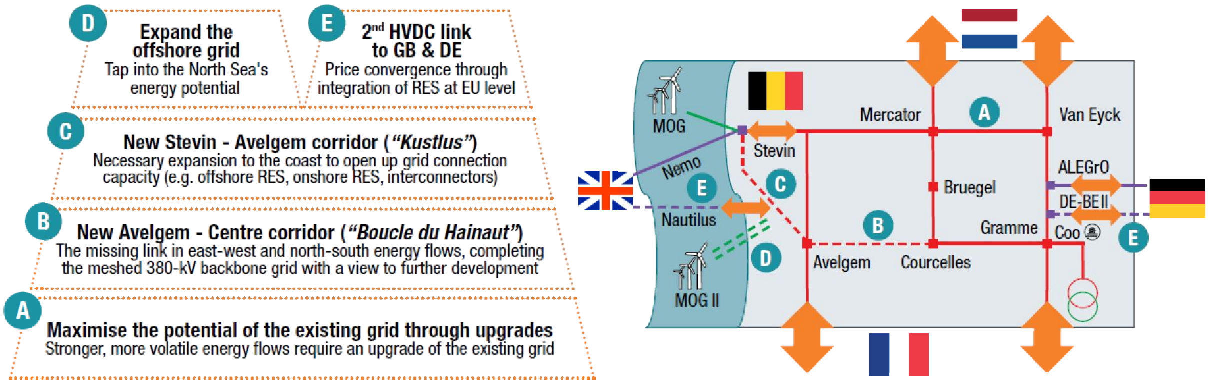

Figure 14: Planned expansion of the expansion of the Belgian 380-kV grid. From [20].

Case study 2: Germany

The EUCO30 scenario expects an increase, moderate but non-negligible (from 7.6 GW to 9.9 GW), of the offshore wind capacity installed in Germany in 2030, compared to 2020. Germany is already suffering from huge congestions between the North and the South of Germany, because the offshore wind is located in the North and the load (and thermal generation) in the South. According to the ENTSO-E transparency platform, the redispatch costs were slightly more than 1 billion of € in 2018. Several HVDC projects are planned to directly connect the North and the South of Germany (i.e. SuedOstLink, SuedLink and Ultranet), as shown in *Figure 15*, but they are suffering from important delays. They are now expected to be commissioned around 2025. If they are actually commissioned by 2030, they should be sufficient to eliminate congestions in the EUCO30 scenario. However, if at least one project is postponed beyond 2030 (or cancelled), several GWs of storage might be needed in the North of Germany. Furthermore, due to the length of the HVDC projects, their cost is substantial. For example, the cost of SuedOstLink is estimated to be around 3 billion of € for a capacity of 2 GW. It means that the cost of a storage unit of 2 GW and of 24 GWh (using also an energy-to-power ratio of 12 hours) could be close to that amount. In other words, storage could be a relevant alternative to long and underground HVDC transmission projects. It must be nevertheless emphasized that, due to the fact that Germany is a unique bidding zone, and due to the bundling of system operator and transmission owner functions in Europe, it would be difficult to find a positive business case for an investor.

Discussion

These two cases show that storage could be an alternative to transmission grid reinforcement, but under two conditions: it must address congestions appearing periodically (e.g. due to PV or wind) to smoothen the power to transfer, and it must address congestions appearing over long distances. If these conditions are not met, its cost would be prohibitive compared to grid reinforcement. The exact needs of storage to mitigate congestions in the transmission system are thus difficult to estimate without a country-by-country detailed analysis, but the case study of Germany can help to derive an order of magnitude. It was shown that a storage capacity of a few GW could be relevant, with an energy-to-power ratio of approximately 12 hours. In terms of annual load, the size of the German power system is approximately one sixth of the EU power system. As a first approximation, the rule of three can tell us that we can expect between a few GW and a few tens of GW. This order of magnitude is consistent but slightly higher than the values given by [21]. Indeed, that reference indicates that the storage needs for transmission asset optimization in Western Europe, representing one third of the total load of the EU power system, is expected to be around 0.6 GW/year in 2026. This difference can be explained by the fact that the two conditions needed for a competitive advantage of storage over transmission grid reinforcement are mainly met in Germany. Based on the analysis of the ENTSO-E TYNDP 2018, two other countries or zones could face congestions appearing periodically and over long distances: Italy and Great Britain, due to their longitudinal structure. Although it does not preclude the use of storage in other countries, the scale is expected to be much lower elsewhere. For instance, the Ringo project in France will lead to the installation of three storage units of 12-15 MW (with an energy-to-power ratio of 2 hours) to solve location congestions in the transmission grid. From these considerations, an upper bound of 10-20 GW can be derived for the needs of storage due to congestions in the transmission system. If an energy-to-power ratio of approximately 12 hours can be useful for the integration of wind energy, a lower energy-to-power ratio (e.g. 4 hours) is sufficient for the integration of solar energy.

It also must be emphasized that the current organization of the electricity market in Europe hampers the development of storage as an alternative to grid reinforcement within a bidding zone: except under specific circumstances, TSOs should not own and operate storage assets to not distort the electricity market, and it is difficult to create a business case for a third-party such as a generating company.

Figure 15: Planned HVDC links in Germany. From [22].

Impact of the distribution system

Introduction

Following the previous section analysing the impact of the transmission system (national level), a complementary analysis is now performed by studying to which extent physical grid constraints impact the storage needs for the distribution system (at subnational level and below). Note that, in this section, battery technology is assumed to be the only source of flexibility to avoid local over-voltage conditions occurring when PV is fed into the grid. Load shifting could be another flexibility option, but it must be emphasized that load curtailment is not an option (i.e. it would aggravate the problem).

To evaluate the impact of the distribution system, the behaviour of several distribution system archetypes will be simulated. Then, the EUCO30 scenario will be transposed to

these archetypes by assuming several different centralized/decentralized fuel mix for the RES penetration. By this way, additional storage/flexibility needs due to distribution grid constraints will be estimated.
It is also important to consider that the analysis only applied to low voltage levels knowing that low voltage is the voltage level that hosts the most congestion issues in distribution networks under high decentralized RES penetration. Therefore, the needs have been evaluated for the integration of PV at low voltage level, other needs inducing indirect impact on the distribution grid have not been considered, such as flexible users in distribution providing adequacy or ancillary services.

Methodology

In this section, the methodology that is used to assess the storage needs at distribution level is described. First, a general overview of our approach is given. Then, a more detailed description of each step and the assumptions that are used behind will follow.

Overview

A general overview of the methodology can be found in Figure 16.

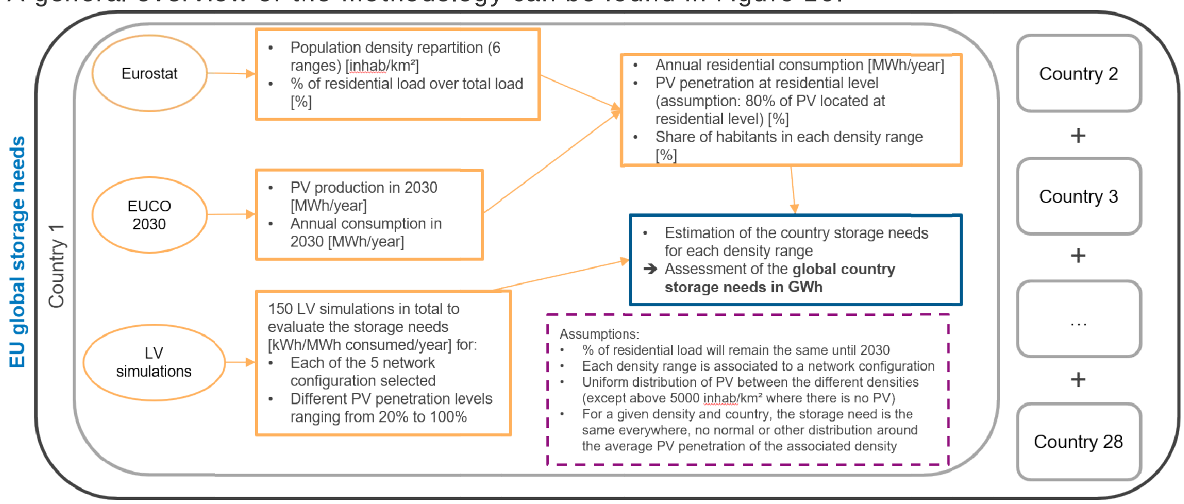

Figure 16: Methodology to assess the impact of the distribution system

Overall, the storage needs are assessed at national level to take into account the local conditions, such as RES targets and the varying fuel mix in RES generation technologies, of each country within the EU. Then, the global needs at EU level are estimated by adding up the needs of each country. For each country, the needs are calculated based on information coming from different, as described in the following sections:

- Eurostat
- EUCO 2030 Scenario
- Low voltage distribution grid simulations

Specific steps and assumptions

As described previously, the storage needs for the whole EU at distribution level are calculated by adding up the storage needs of each country individually. For each country, the steps and assumptions to evaluate the storage needs in 2030 are the following:

1. From Eurostat, the following data have been collected:
   a. The population density repartition with 6 ranges in inhabitants per km²
   b. The percentage of residential load over the total country load. Knowing that most part of the loads connected to the low voltage network are residential, it is assumed that the share of residential load over the total country load is equivalent to the share of load on the low voltage network over the load on the whole electrical network.

   The data coming from Eurostat are current data, it is assumed that they will remain unchanged until 2030.

2. From the EUCO 2030 Scenario, the following data have been retrieved:
   a. The annual photovoltaic production in 2030 at country level (in MWh per year)
   b. The annual consumption in 2030 of the whole country (in MWh per year)
3. Then, using data from steps 1 and 2, the following parameters can be deduced:
   a. The annual residential consumption in 2030 at country level (in MWh per year)
   b. The annual photovoltaic production at residential level in 2030 from which is deduced the PV penetration level at residential level (ratio between annual production and annual consumption at residential level). The annual photovoltaic production at residential level is calculated assuming that 80% of the PV plants will be located at residential level.
   c. The share of inhabitants within each density range (in percentage) is deduced from the population density repartition.
4. A set of 150 low voltage grid simulations was performed to assess storage needs in many different configurations (more information can be found in section 0):
   a. Five different network configurations were simulated to take into account the variation of storage needs due to the network configuration (distance between consumers, cable/overhead line type, etc.)
   b. Different PV penetration levels were simulated for each network configuration, with an annual production ranging from 20% to 100% of the annual load consumption.

   It is assumed that each network configuration is associated to a density range (depending on the length between consumers on the feeder, see section 0). For each simulation, the storage need is calculated in kWh of storage per MWh consumed per year.

5. Thanks to the storage needs evaluated in step 4 and parameters calculated in step 3, the estimation of the storage need for each density range can be calculated. From those figures, the global country storage needs in GWh can be deduced. To calculate the storage needs for each density range, the following assumptions were made:
   a. The PV production is uniformly distributed between the different densities, except above 5000hab/km² where it is assumed that the PV penetration is neglectable due to very high population density.
   b. For a given density and country, the PV production is uniformly distributed, which leads to the same storage need everywhere, i.e. no normal or other distribution around the average PV penetration of the associated density.

The process and methodology to calculate the storage needs in 2030 is the same for every country. After having calculated that, the global storage need for EU is estimated by summing up the storage needs that have been found for each country.

Distribution grid simulations

As briefly discussed in previous section, the storage needs are assessed through low voltage distribution grid simulations using a software tool. It is more specifically evaluated from a PV hosting capacity perspective in residential distribution networks. Indeed, the goal is to calculate the volume of storage needed for different hosting capacities while keeping a limited amount of curtailment. To do so, the strategy is the following:

- Five representative configurations of typical low voltage networks are selected, each of them is linked to a density range.
- An assumption is made on the acceptable level of PV curtailment (due to congestion issues such as over-voltage issue or cable capacity issue): max 3% of the yearly production can be curtailed. This limit is used to calculate the hosting capacity.
- Load profiles are typical electricity demand profiles from West Europe (Belgium) without electrical heating and without air-conditioning.
- The hosting capacity is evaluated (without storage) at low voltage level from 20% PV penetration to 100% PV penetration for the different representative LV configurations
- For each network configuration, the storage needs to reach the different levels of PV penetration (from 20% to 100%) is calculated with the constraint of respecting the maximum amount of curtailment. This is calculated by finding the storage size (in kWh of storage per MWh consumed per year) that allows staying below 3% curtailment for a given PV penetration (hosting capacity).

Then, as explained in the methodology, based on the density repartition (Eurostat) and PV penetration level in 2030 (EUCO2030 scenario), the storage needs can be extrapolated for each country.

Software tool description

The software tool used for the simulations is a distribution network simulation tool [23]. This tool is used to optimize and analyse the planning and operation of distribution networks. The optimization can use smart solutions, such as demand response, batteries, EVs, etc. to decrease/avoid congestion issues on the network at the lowest cost.

The tool uses a state-of-the-art multi-period AC Optimal Power Flow (OPF) calculation method. OPF problems have been formulated to optimize operational dispatch choices (i.e. decision variables) with the objective of reaching the lowest operation costs under different constraints (load flow equations, voltage and current limits, production assets limits, etc.).

The structure of the tool is focused on radial networks to optimize the calculation speed for radial distribution networks. A convex relaxation method (SOCP) is used, the exactness of which is achieved by minimizing the error on the inequation used to relax the problem. This method is complex but allows reaching the exact solution because no assumption is made on the load flow equations. The tool includes a library of flexible models for generic loads and generators, as well as a library of technology-specific models for PV, wind, EVs and stationary battery storage.

The OPF calculation core tackles low voltage and medium voltage studies, both simultaneously and separately. The mathematical methods used are validated, robust and have sufficient numerical performance to simulate radial networks of different voltage levels, with combinations of cables and lines, and for varying X / R ratios.

Selection of the networks

The selection of representative network configurations is based on the LV circuit length per LV consumer provided by the JRC in the *Distribution System Operators Observatory* [24]. This report provides information and distribution functions of various indicators (such as the LV circuit length per LV consumer used in this report) for distribution networks in Europe (data provided by many DSO from the different EU members).

The distribution of LV circuit length per LV consumer in EU can be found in Figure 17. As can be seen in this Figure, the LV circuit length per LV consumer ranges from 0.008 to 0.08 km / LV consumer. To cover that range in the analysis, a selection of five values to be used within the range was carried out as follows:

- 0.055 km / LV consumer, which corresponds approximatively to the 0.95 percentile of the distribution
- 0.010 km / LV consumer, which corresponds approximatively to the 0.05 percentile of the distribution
- 0.023 km / LV consumer, which corresponds to the median of the distribution
- 0.029 km / LV consumer, which is between the median and the 0.95 percentile of the distribution
- 0.018 km / LV consumer, which is between the median and the 0.05 percentile of the distribution

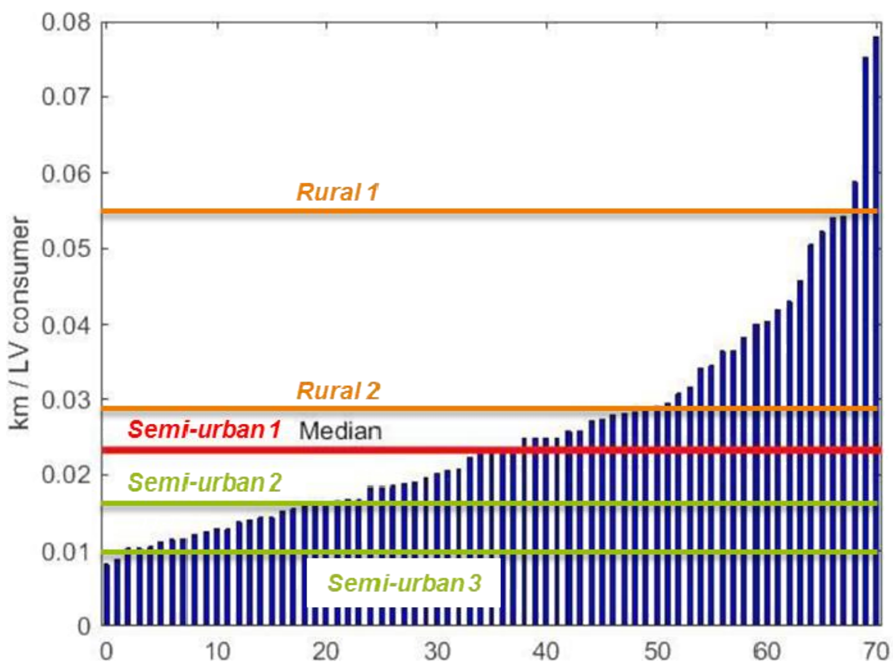

Figure 17: LV circuit length per LV consumer [24]

To match those selected distances between LV consumers, a set of five corresponding representative LV feeder configurations were selected:

- 2 representative distribution networks were derived from a rural feeder (20 consumers)
- 3 representative distribution networks were derived from a semi-urban feeder (41 consumers)

The characteristics of those five distribution networks are summarized in Table 4. As can be seen, the rural feeders have an overhead line while semi-urban feeders have an underground cable.

Network name	Area	N° of households	Average distance between consumers [km]	Overhead or underground	Main cable size [mm²]	Cable type	Cable max apparent power [kVA]
Rural 1	Rural	20	0.055	Overhead	120	Al	146
Rural 2	Rural	20	0.029	Overhead	70	Al	170
Semi-urban 1	Semi-urban	41	0.023	Underground	120	Al	146
Semi-urban 2	Semi-urban	41	0.018	Underground	120	Al	146
Semi-urban 3	Semi-urban	41	0.010	Underground	120	Al	146

Table 4: Characteristics of the representative distribution networks

Then, to make the link between the network configurations and the population density given by Eurostat, each density range is attributed to one of the network configurations (see Table 5). It must be noted that the density range > 5000 inhabitants per km² (which corresponds to an urban area) is not modelled since it is assumed that the PV penetration is neglectable in those areas. This assumption will hold until new PV technologies reach market readiness (see building integrated PV).

Network name	Density range [inhab/km²]
Rural 1	1 – 4
Rural 2	5 – 19
Semi-urban 1	20 – 199
Semi-urban 2	200 – 499
Semi-urban 3	500 – 5000

Table 5: relation between network configurations and density ranges

Set of simulations

Simulations results

A summary of the LV simulations results can be found in *Table 6* and *Figure 18*. The following observations can be made:

- No storage is needed up to 20% PV penetration, no matter the network configuration;
- Without storage, the hosting capacity is between 20% and 60% depending on the network configuration;
- Storage size needed to stay below the limit of 3% curtailment:
  - Between 1 and 2 kWh/(MWh consumed per year) for PV penetration up to 80%;
  - Large increase of storage needs between 80 and 100% PV penetration, with a capacity that goes up to 10 kWh/(MWh consumed per year).

Figure 19 shows the evolution of PV curtailment as a function of the PV penetration without any storage (no flexibility to help reducing the curtailment). It can be seen that the curtailment goes up to 40% without the help of storage.

Storage needs [kWh/MWh consumed/year]		Network configuration				
		Rural 1 (1 - 4 inhab/km²)	Rural 2 (5 - 19 inhab/km²)	Semi-urban 1 (20 - 199 inhab/km²)	Semi-urban 2 (200 - 499 inhab/km²)	Semi-urban 3 (500 - 5000 inhab/km²)
PV penetration level [%]	0	0	0	0	0	0
	0.2	0.00	0.00	0.00	0.00	0.00
	0.4	0.52	0.00	0.59	0.34	0.00
	0.6	0.96	0.71	0.99	0.90	0.56
	0.8	1.89	1.40	1.95	1.79	1.01
	1	9.41	2.27	10.47	3.75	1.94

Table 6: Results of LV simulations

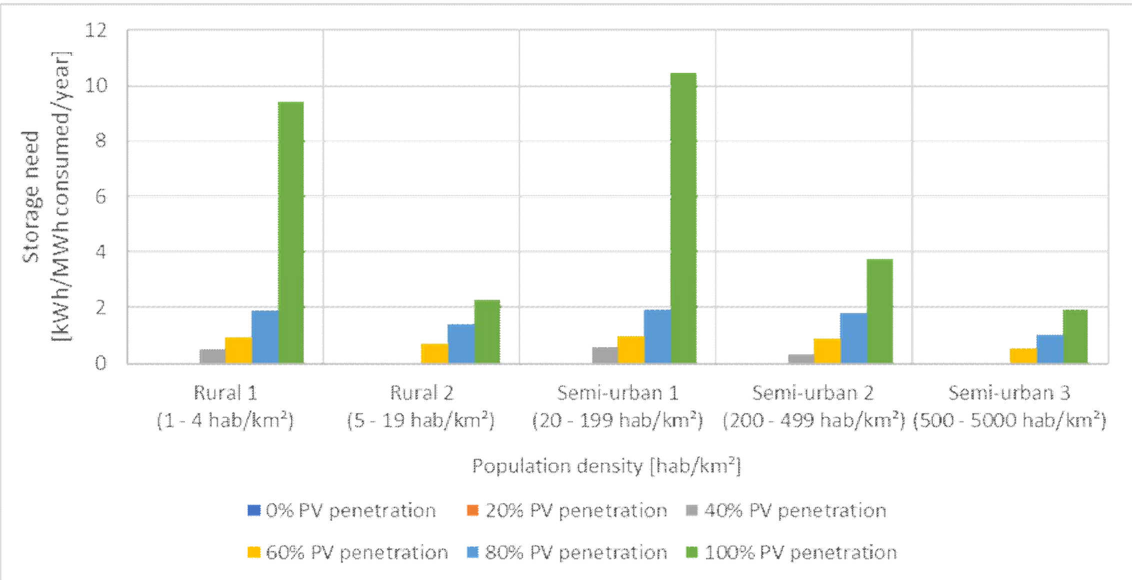

Figure 18: Results of LV simulations

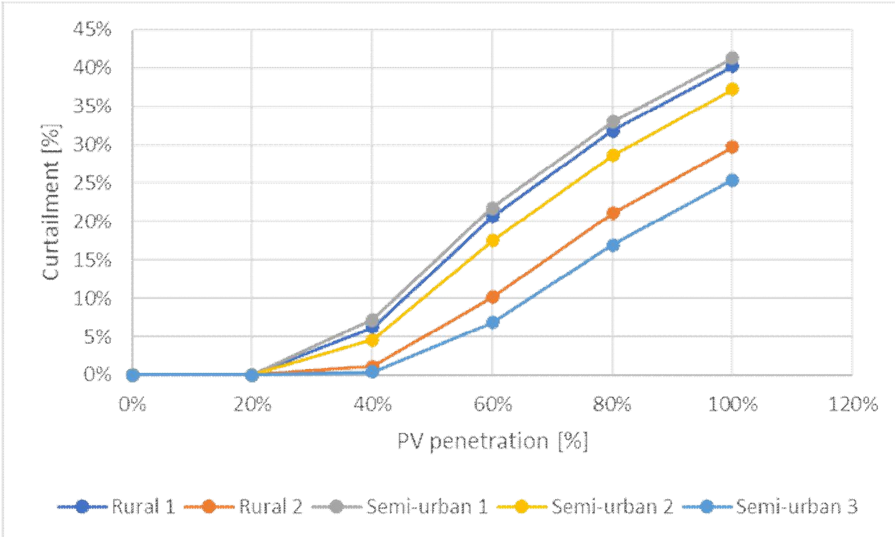

Figure 19: Evolution of curtailment with PV penetration at low voltage

Analysis of the storage needs per country

Using the different steps of the methodology that have been explained in section 0 and the results of the LV simulations in section 0, the storage needs per country can be evaluated. Main results from the methodology as well as the storage needs per country can be found in Table 7. The total storage need for the whole EU28 can be found at the last row. Based on those figures, following conclusions can be made:

§ Around 330 GWh are needed for the EU28, in terms of investment it roughly corresponds to 150 000 M€ if Li-ion battery technology is used[26]. Note that these numbers are illustrative and dependent on the actual deployment of the scenario used in this study. Spatial allocation is also something that will have a fundamental impact on the storage need and the costs.;

§ Italy, Spain and Germany represent more than 80% of the global storage need for two reasons: they are large countries and the forecasted PV penetration levels for 2030 are high. Figure 20 that shows a bar chart of the global storage need per country confirms that observation: the need is concentrated in few countries;

Countries in the North and countries with limited PV penetration levels have no or a very limited storage need. This can be seen in Figure 21 that shows the average storage need per MWh consumed per year in every country: Most countries from the South have a large storage need while countries from the North have a limited or no storage need. This is mainly due to EUCO 2030 scenario that forecasts more PV in the South than the North of Europe.

[26] Assuming an energy-to-power ratio of 2 and an investment cost of 450 €/kWh

		Population share per density [%]							Energy consumed per density [GWh/year]							Average PV penetration (no PV if >5000 inhab/km²) [%]							Storage need per MWh consumed per density [kWh/MWh/year]							Storage need per density [GWh]						
Country	Country code	1 4	5 19	20 199	200 499	500 5000	> 5000	*Global*	1 4	5 19	20 199	200 499	500 5000	> 5000	Global	1 4	5 19	20 199	200 499	500 5000	> 5000	Global (AVERAGE)	1 4	5 19	20 199	200 499	500 5000	> 5000	Global (AVERAGE)	1 4	5 19	20 199	200 499	500 5000	> 5000	Global
Italy	IT	0.1%	0.3%	8.7%	0.7%	55.7%	34.5%	100%	57	185	5799	501	37297	23076	66916	95%	95%	95%	95%	95%	0%	62%	7.5	2.1	8.3	3.3	1.7	0.0	3.8	0.4	0.4	48.1	1.6	63.6	0.0	114.1
Spain	ES	0.2%	1.2%	11.0%	2.3%	28.9%	56.4%	100%	148	942	8376	1734	22049	43001	76250	115%	115%	115%	115%	115%	0%	50%	9.4	2.3	10.5	3.8	1.9	0.0	4.6	1.4	2.1	87.7	6.5	42.9	0.0	140.6
Malta	MT	0.1%	0.1%	5.7%	1.5%	83.6%	9.0%	100%	0	1	47	13	697	75	833	54%	54%	54%	54%	54%	0%	49%	0.8	0.5	0.9	0.7	0.4	0.0	0.6	0.0	0.0	0.0	0.0	0.3	0.0	0.3
Germany	DE	0.2%	0.3%	8.3%	0.7%	77.1%	13.4%	100%	297	388	10834	933	101136	17559	131147	53%	53%	53%	53%	53%	0%	46%	0.8	0.5	0.9	0.7	0.4	0.0	0.5	0.2	0.2	9.3	0.7	37.8	0.0	48.1
Greece	EL	0.2%	0.6%	15.2%	1.2%	43.0%	39.8%	100%	29	118	2821	222	8002	7410	18601	76%	76%	76%	76%	76%	0%	46%	1.7	1.3	1.8	1.6	0.9	0.0	1.2	0.0	0.1	5.0	0.4	7.4	0.0	13.0
Slovenia	SI	0.3%	0.8%	13.3%	2.6%	67.8%	15.3%	100%	10	29	477	92	2439	551	3597	54%	54%	54%	54%	54%	0%	45%	0.8	0.5	0.9	0.7	0.4	0.0	0.5	0.0	0.0	0.4	0.1	0.9	0.0	1.4
Cyprus	CY	0.2%	0.6%	15.2%	1.2%	43.0%	39.8%	100%	3	11	259	20	735	681	1709	65%	65%	65%	65%	65%	0%	39%	1.2	0.9	1.2	1.1	0.7	0.0	0.8	0.0	0.0	0.3	0.0	0.5	0.0	0.8
Ireland	IE	0.1%	0.8%	7.7%	0.5%	62.5%	28.4%	100%	12	69	690	45	5576	2537	8928	43%	43%	43%	43%	43%	0%	31%	0.6	0.1	0.7	0.4	0.1	0.0	0.3	0.0	0.0	0.4	0.0	0.5	0.0	1.0
Bulgaria	BG	0.6%	3.8%	26.7%	9.0%	35.6%	24.3%	100%	62	401	2828	955	3774	2572	10591	40%	40%	40%	40%	40%	0%	30%	0.5	0.0	0.6	0.3	0.0	0.0	0.2	0.0	0.0	1.7	0.3	0.0	0.0	2.1
Portugal	PT	0.1%	0.5%	8.6%	4.4%	39.7%	46.7%	100%	12	69	1131	576	5200	6115	13102	55%	55%	55%	55%	55%	0%	30%	0.9	0.5	0.9	0.8	0.4	0.0	0.6	0.0	0.0	1.0	0.4	2.3	0.0	3.8
Belgium	BE	0.1%	0.1%	5.7%	1.5%	83.6%	9.0%	100%	10	21	1168	312	17166	1846	20525	32%	32%	32%	32%	32%	0%	29%	0.3	0.0	0.4	0.2	0.0	0.0	0.1	0.0	0.0	0.4	0.1	0.0	0.0	0.5
Austria	AT	0.4%	0.7%	13.8%	1.5%	75.6%	7.9%	100%	87	152	2819	305	15413	1611	20386	31%	31%	31%	31%	31%	0%	28%	0.3	0.0	0.3	0.2	0.0	0.0	0.1	0.0	0.0	0.9	0.1	0.0	0.0	1.0
Luxembourg	LU	0.2%	0.3%	8.2%	1.4%	83.1%	6.7%	100%	2	4	91	16	918	74	1104	29%	29%	29%	29%	29%	0%	27%	0.2	0.0	0.3	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Poland	PL	0.2%	0.6%	16.4%	0.5%	60.7%	21.6%	100%	80	187	5521	177	20395	7253	33612	32%	32%	32%	32%	32%	0%	25%	0.3	0.0	0.4	0.2	0.0	0.0	0.1	0.0	0.0	1.9	0.0	0.0	0.0	2.0
Croatia	HR	0.3%	1.0%	13.8%	1.9%	70.0%	13.1%	100%	19	67	941	127	4772	893	6821	26%	26%	26%	26%	26%	0%	23%	0.2	0.0	0.2	0.1	0.0	0.0	0.1	0.0	0.0	0.2	0.0	0.0	0.0	0.2
Czech Republic	CZ	0.4%	1.0%	15.2%	3.0%	62.8%	17.6%	100%	71	167	2529	492	10431	2919	16609	27%	27%	27%	27%	27%	0%	22%	0.2	0.0	0.2	0.1	0.0	0.0	0.1	0.0	0.0	0.5	0.1	0.0	0.0	0.6
Netherlands	NL	0.1%	0.1%	5.6%	0.0%	61.8%	32.5%	100%	13	20	1304	8	14485	7606	23435	31%	31%	31%	31%	31%	0%	21%	0.3	0.0	0.3	0.2	0.0	0.0	0.1	0.0	0.0	0.4	0.0	0.0	0.0	0.4
France	FR	0.4%	1.1%	11.3%	2.5%	69.3%	15.4%	100%	611	1832	19136	4303	117392	26102	169376	22%	22%	22%	22%	22%	0%	19%	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	1.4	0.2	0.0	0.0	1.6
Romania	RO	0.4%	1.8%	13.8%	9.6%	46.3%	28.1%	100%	55	258	1948	1351	6531	3963	14107	22%	22%	22%	22%	22%	0%	15%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.1
United Kingdom	UK	0.0%	0.1%	3.1%	0.1%	55.8%	40.9%	100%	58	121	3917	126	71027	52009	127259	20%	20%	20%	20%	20%	0%	12%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hungary	HU	0.4%	1.2%	11.3%	2.8%	61.2%	23.1%	100%	46	141	1307	323	7076	2678	11571	15%	15%	15%	15%	15%	0%	11%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Estonia	EE	0.6%	4.9%	22.0%	7.6%	48.2%	16.6%	100%	12	91	411	143	900	310	1866	11%	11%	11%	11%	11%	0%	9%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Slovak Republic	SK	0.1%	0.7%	22.3%	0.4%	59.8%	16.6%	100%	9	43	1323	22	3542	983	5921	10%	10%	10%	10%	10%	0%	8%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Denmark	DK	0.2%	0.3%	9.8%	0.0%	82.9%	6.8%	100%	29	32	1164	0	9845	810	11881	6%	6%	6%	6%	6%	0%	5%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sweden	SE	0.6%	2.2%	14.1%	0.6%	75.1%	7.5%	100%	304	1143	7474	299	39848	3975	53042	3%	3%	3%	3%	3%	0%	3%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Lithuania	LT	0.7%	3.3%	16.8%	7.5%	38.9%	32.7%	100%	22	98	492	220	1141	959	2931	3%	3%	3%	3%	3%	0%	2%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Latvia	LV	1.0%	6.9%	23.7%	2.2%	44.6%	21.6%	100%	23	159	546	50	1029	499	2306	0%	0%	0%	0%	0%	0%	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Finland	FI	0.4%	2.0%	20.0%	8.0%	66.1%	3.5%	100%	106	482	4813	1924	15896	844	24065	0%	0%	0%	0%	0%	0%	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EU28		0.2%	0.7%	9.9%	1.8%	60.0%	27.3%	100%	1894	6217	87165	15953	525817	239083	876129	39%	39%	39%	39%	39%	0%	28%	0.5	0.0	0.5	0.3	0.0	0.0	0.2	2.3	2.9	159.9	10.5	156.2	0.0	331.7

Table 7: Main distribution results resulting from methodology and storage needs per country

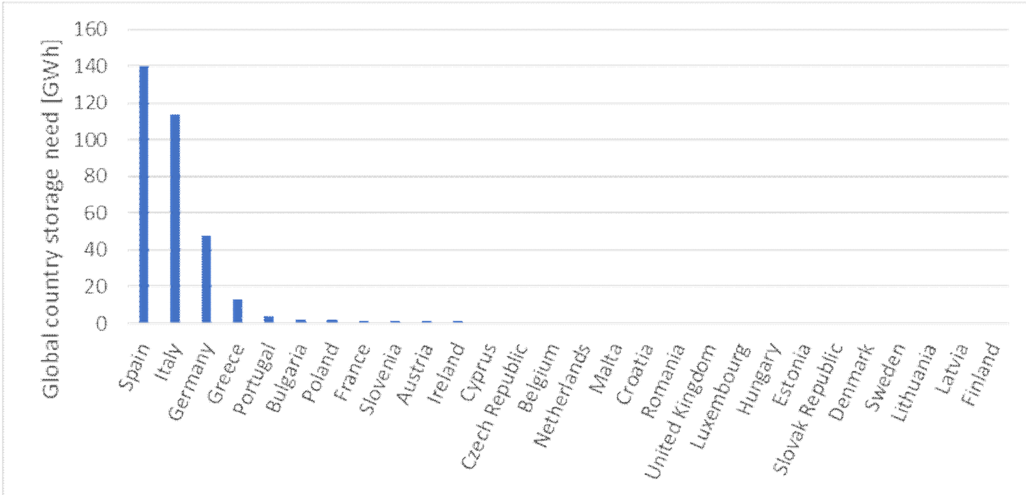

Figure 20: Global storage need per country for distribution

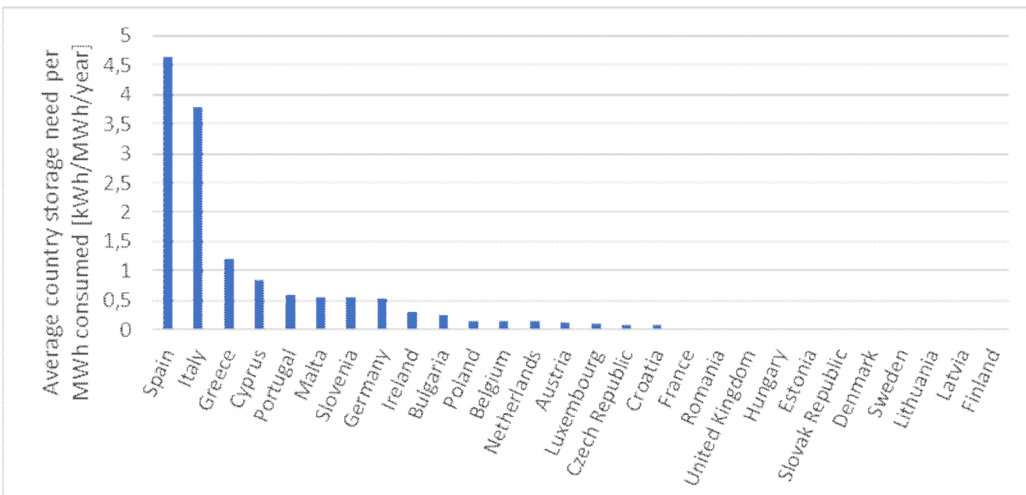

Figure 21: Average country storage need per MWh consumed per year at distribution level

Figure 22 shows geographically how the need is spread all over Europe. The map clearly shows that the storage need increases from North to South with Spain and Italy as most critical countries.

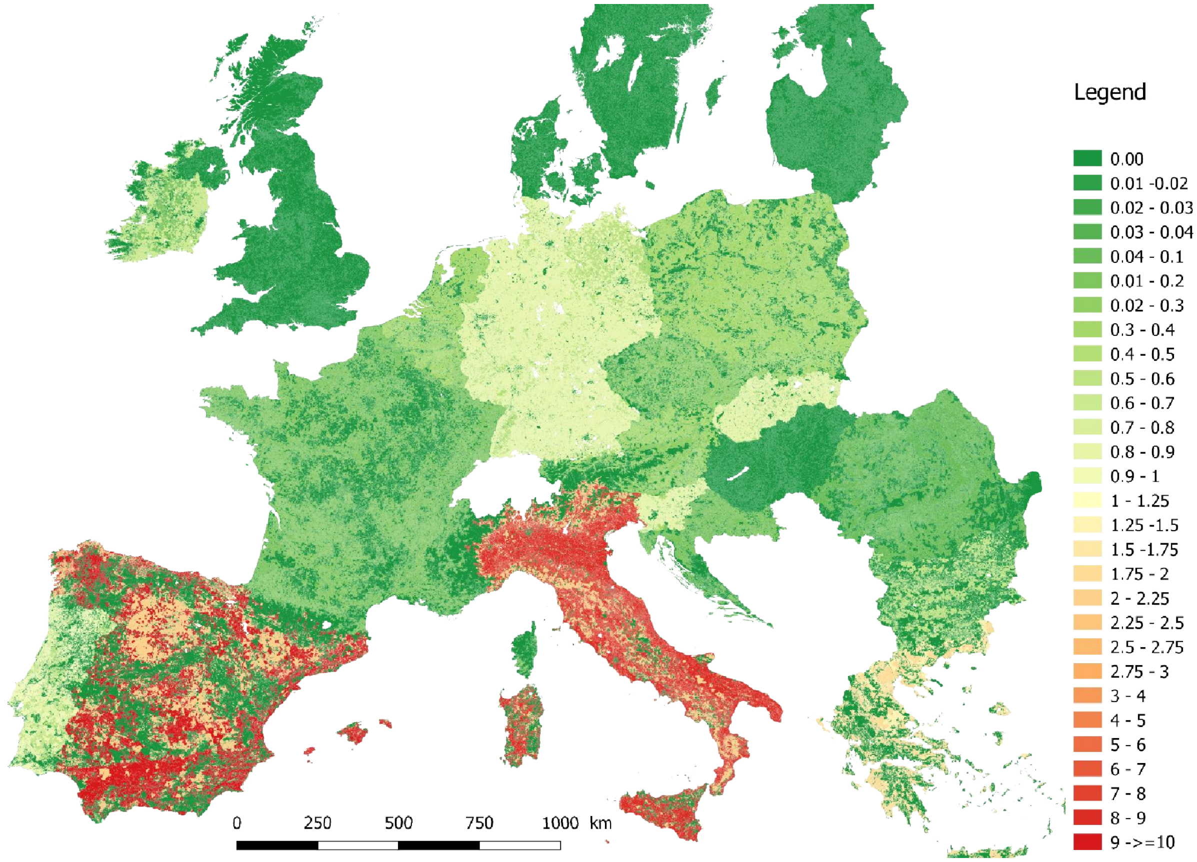

Figure 22: Map of the storage needs at distribution level for the whole EU28

Finally, a sensitivity analysis can be carried out. If, for example, it is assumed that 60% (instead of 80%) of the PV plants will be located at residential level, the storage need at distribution level is inherently different. Figure 23 and Figure 24 show the global storage need per country as well as the average storage need per MWh consumed per year at country level. It can be seen that the trends remain the same even though the figures are different. Indeed, the global storage need at EU28 level decreases to 140 GWh in 2030 with this new assumption. This clearly shows that the figures must be used carefully because they are very sensible to where and how much PV will be located at low voltage level.

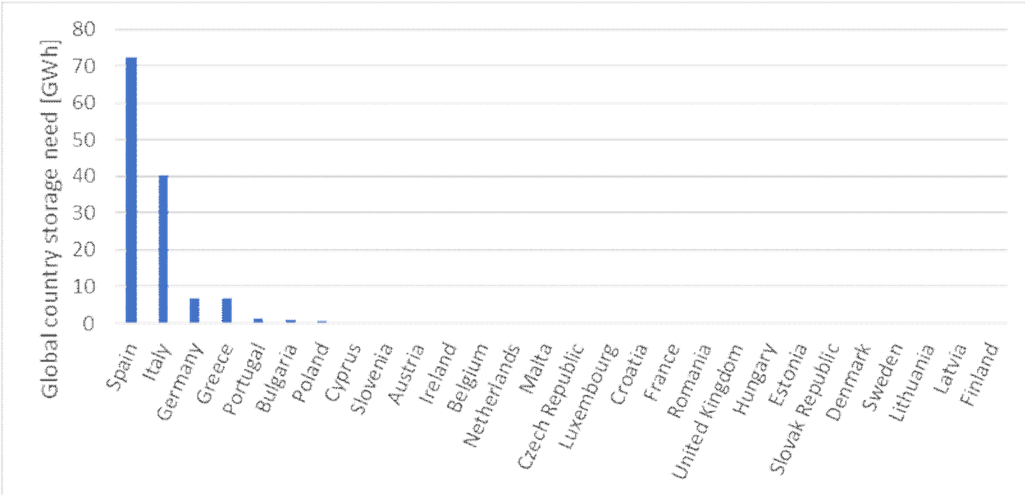

Figure 23: Global storage need per country for distribution (variant with 60% PV penetration at residential level)

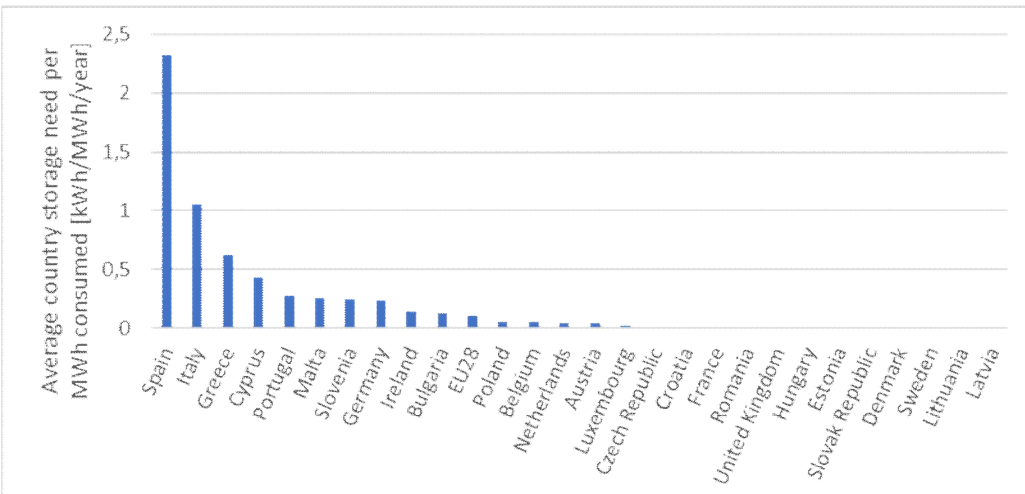

Figure 24: Average country storage need per MWh consumed per year at distribution level (variant with 60% PV penetration at residential level)

Further areas to investigate

Throughout the analysis, several assumptions were made to allow estimating the storage needs at distribution level. As in any macro analysis, it is always possible to complexify the method used to assess the need. Several areas that could be investigated or could serve as improvement of the model are the following:

- The analysis focused on the low voltage level of the distribution grid since it is the voltage level that hosts the most issues due to renewable penetration in distribution networks. However, having an analysis for the medium voltage level may improve the level of accuracy by taking into account the whole distribution system.
- Other or additional criteria than population density could be used to generate results for each country. Potential options for a multi-criteria approach are:
    - Different network configurations that are specific to each country with a certain distribution for each type of network;

- o Load profiles that are specific to each country and / or network type in 2030;
- o Non-uniform PV penetration distribution over each country (for example with variations from one network configuration to another and also variations within a given network configuration);
- o Improve the assumptions of the split of PV at residential, tertiary and industrial levels.

Synthesis of the needs

The analyses performed in this chapter demonstrate that in 2030, in the EUCO30 scenario, the flexibility requirements will increase to address the variability of renewable energy sources. If grid constraints within each country are ignored, and assuming a full removal of market distortions, this increase of the needs can be met by an increase of the storage capacity from 47 GW to 59 GW (+12 GW), requiring additional pumped hydro storage and batteries, and by the natural replacement of old thermal power plants by new and more flexible thermal power plants. Beyond this limited increase of the flexibility and storage need to balance the load and the generation at a national level, constraints within the transmission and the distribution systems lead to additional flexibility needs. In order to quantify the needs, storage is considered to be the only flexibility provider. At the level of the transmission system, storage could appear as an alternative to grid reinforcement, especially when the underlying congestions appear on long distances and when permitting issues are hampering transmission projects. The order of magnitude of the storage needs at transmission level will likely be of a few GW (up to 10-20 GW) and a few tens of GWh, but the current organization of the power market does not encourage such investments. This is an issue to be solved through the implementation of the Clean energy package. Finally, major storage needs are expected in the distribution system for countries with a large share of PV (Italy, Spain and, to some extent, Germany). The exact needs will depend strongly on the way PV will actually be developed (i.e. centralized or decentralized), but it could be between 100 GWh and 300 GWh, i.e. a capacity between 50 GW and 150 GW. As a consequence, the total need of additional storage capacities appears to be between 75 GW and 185 GW, with a large share for the distribution system. It must be nevertheless emphasized that electric vehicles could bring a large part of that flexibility: in the EUCO30 scenario, around 20-30 millions of electric vehicles are expected in Europe by 2030, which could represent a power of about 100-150 GW, but that their actual contribution of electric vehicles will depend on the degree of smart charging [25]. This flexibility within the distribution grid could also be brought partially through load shifting (e.g. smart electricity based heating devices). Note that, in any case people will often want to store solar electricity from their solar panels for self-consumption, especially if their electric vehicles are stored in office buildings during the day time.

Conclusions

In order to achieve the 2030 climate and energy targets as agreed by the European Council in 2014, the European power system will have to accommodate an important share of renewable energy sources. In order to deal with the variability of these renewable energy sources and to reach thus the target, the integration of storage and flexibility solutions in the European power system will be needed. This report studies the characteristics of storage and flexibility means, as well as the expected needs of storage and flexibility in 2030 in the specific context of the EUCO30 scenario. This core policy scenario was created using the PRIMES model with the EU Reference Scenario 2016 as a starting point in the context of the 2016 Impact Assessment work of the European Commission. It models the achievement of the 2030 climate and energy targets, with a 30% energy efficiency target.

The first part of the assessment of storage and flexibility needs, focusing on the balancing of load and generation at a national level shows that requirements of flexibility in the power system are expected to increase by 2030. It is mainly due to an important increase of variable RES, and primarily of solar PV, because the deployment of wind and in particular of offshore wind is of lower concern regarding the multi-hour flexibility requirement. In the EUCO context, the needs for short and multi-hour flexibility are projected to represent 21% of total electricity generation in 2030 in the EU28. Conventional ancillary services (mainly frequency restoration reserve) are able to handle almost half of the flexibility needs in 2030; more specifically by addressing short-term flexibility. However, the variable RES may also require additional services for short-term flexibility that go beyond the conventional reserves, as they may imply rising demand for fast-ramping short-term spinning reserves, in addition to current capabilities. Also, the system would experience by 2030 the emergence of fast-ramping as a systematic feature of the rising multi-hour flexibility. Comparing the flexibility needs in 2030 with the current levels (e.g. in 2015) has not been easy, as lack of data does not allow calculating the flexibility measurements fully. However, a rough estimation indicates that the flexibility needs are in the order of 10% of total electricity generation in 2015 in the EU28, of which a little above half are short-term flexibility needs covered by conventional ancillary services. The needs for multi-hour flexibility will increase by 28% between 2015 and 2030. %. If we assume a full removal of market distortions, this increase of the needs can be met mainly by an increase of 12 GW of the storage capacity (+26%, mainly batteries and additional pumped hydro storage) covering around 16% of flexibility needs together with demand response, and by the natural replacement of old thermal power plants by new and more flexible thermal power plants. In other words, only a moderate increase of the flexibility means is expected by 2030 to balance the system at a national level. Nevertheless, it must be emphasized that the assumption of full removal of market distortions is a major prerequisite to reach that conclusion. Indeed, the removal of distortions allow for a larger sharing of the resources, which provide increased opportunities for the systems to use the (dispatchable) RES and the flows over interconnections as a source of flexibility: this assumption of perfect implementation of the market design initiative implies an almost doubling of power exchanges between areas within the intraday transactions, compared to a case assuming continuation of market distortions. As a consequence, an imperfect implementation of the market design initiative would result in the need of additional storage and flexibility means at a national level.

While generation can match the load at a national level with limited increase of storage capacity under this assumption of full removal of market distortions, congestions within the transmission or the distribution grid can hamper the transfer of electricity from the generators to the loads. Thus, grid constraints might lead to significant additional flexibility needs. This is in particular the case for countries that are expected to host a large share of solar PV in their power system by 2030 (Italy, Spain and, to some extent, Germany). In order to quantify the needs, storage is considered to be the only flexibility provider. Nevertheless, it must be emphasized that other flexibility means (e.g. demand response such as load shifting or electric vehicles) could also be used in complement or instead of storage. The exact needs will depend strongly on the split between centralized and decentralized solar PV (i.e. if it is fully centralized, there will be no flexibility need in the distribution system). The storage needs at distribution level could be anywhere between 100 GWh and 300 GWh in 2030 (i.e. installed capacity between 50 GW and 150 GW). Because the storage capacity currently installed in distribution grids is marginal, these figures indicate directly the additional storage needs.

At the level of the transmission system, storage could appear as an alternative to grid reinforcement, especially when the underlying congestions appear on long distances, which means that the comparison of cost-benefit analyses of storage and of transmission reinforcement could reveal storage as the best option, and when permitting issues are hampering transmission projects. The order of magnitude of the additional storage need (batteries) at transmission level would be of a few GW and a few tens of GWh, but the current organization of the power market in most Member States (as it stands before the transposition of the new market design rules) does not encourage such investments.

In a nutshell, in the framework of the EUCO30 scenario, additional storage in 2030 is expected to be mainly needed at the level of the distribution system and mainly in some specific countries. A moderate increase of storage and flexibility means to balance the system at a national level and to manage congestions within the transmission system is expected. However, it must be noted that there is some uncertainty about the exact way the power system will evolve by 2030 and storage and flexibility needs might thus be slightly different from the values given in this report. For instance, the installed capacity of solar PV in Europe in 2030 in the ENTSO-E "Distributed Generation" (DG2030) scenario is 420 GW, while it is 236 GW in the EUCO30 scenario. Storage might thus be needed in other countries such as the Netherlands (with 14.1 GW of solar PV in the DG2030 scenario compared to 5.9 GW in the EUCO30 scenario). Furthermore, a large increase of variable renewable energy sources is expected between 2030 and 2040: in the EUCO30 scenario, the total installed capacity of solar PV and wind amounts 535 GW, while in the ENTSO-E scenarios for 2040 it amounts between 758 GW and 1212 GW. This trend is expected continue between 2040 and 2050, leading to an increase of the multi-hour flexibility needs in EU28 by more than a factor 2. Indeed, the measurement of flexibility requirements confirms a clear dependence on the deployment of variable RES and finds a nonlinearly increasing effect of the increase in the share of variable RES on the total amount of flexibility requirements. As a consequence, to meet these needs, total storage capacity would have to increase by a factor 2-3 by 2050 to balance the generation and the load at a national level, in the context of the EUCO scenarios, to reach 137 GW. It will thus be important to prepare the system to absorb these large amounts of variable renewable energy sources during the upcoming decade.

Appendix 1: Additional technology overview for energy storage

(Super-/Ultra-) Capacitors

Capacitors have very low energy contents and short discharge durations and are therefore used in the electricity system for short term balancing as well as compensation of short voltage fluctuations. [12]
Super- or ultra- capacitors are advanced capacitors that have higher energy storage capacities than conventional capacitors, and can discharge over longer time periods. They are able to respond very quickly through both charge and discharge cycles, and provide a high power output over a very short response time. [15]
Capacitors have been in commercial use for decades in transportation and grid back up applications such as wind pitch control systems. In these applications they demonstrate a long cycle life (~1 million cycles) and calendar life (10-25 years) as well as a wide operating temperature range of -40°C to +65°C. The deployment of super-/ultra- capacitors for grid applications is growing. Capacitors in grid applications can be set up as a stand-alone technology or hybridized with a second, low-cost high energy density technology, such as flow batteries and high energy Li-ion batteries. [15]

(Super-/Ultra-) Capacitors	Today	2030
Flexibility	Energy/power ratio (e.g. MWh/MW, discharge time) Milliseconds to minutes	
Efficiency	~ 95%	
Investment costs	300 €/ kW (cell basis); 800 €/kWh	
Variable costs	Unknown	
Lifetime	500,000 – 1,000,000 cycles	
Operational constraints	Short duration	
Installed capacity today	Low, around 3 MW in EU-28	
Maturity	Low § Discovery in 1957, niche uses since the early 1980s; broader use of capacitors has accelerated over the last 15 years § Already widely commercialized in hybrid bus, rail, and automotive applications, as well as back-up power applications such as wind pitch control systems and uninterrupted power supplies § Demonstration/piloting phase for grid energy storage systems	
Environmental effects	N/A	
Barriers	§ Limited fields of application due to very short duration § Limited by production capacities (mostly out of Europe)	
Potential flexibility functions	§ Transmission line stability § Secondary and tertiary frequency control	

	§ Renewables intermittency smoothing

Sources: [15], [16], [15].

Compressed Air Energy Storage (CAES)

Compressed air energy storage (CAES) systems charge energy by converting electrical energy into potential energy of pressurised air. The compressed air can then be stored in underground caverns or in above surface pressure tanks. Heat generated during compression can be stored to increase the round-trip efficiency. During the discharge the air from the cavern or pressure vessel is released and drives the ex-pander of an expander. Before the expansion the compressed air must be preheated to avoid freezing of the expander.

In Europe there is currently only one large scale 290 MW underground CAES installed in Germany and operational since 1978. Another large-scale plant is planned to be built in Northern Ireland. Other sites are considered in other countries (e.g. Netherlands).

Compressed Air Energy Storage (CAES)	Today	2030
Flexibility	Energy/power ratio (e.g. MWh/MW, discharge time) 3 - 20 hours	
Efficiency	40 - 53%	
Investment costs	500 - 2000 €/kW	
Variable costs	Unknown	
Lifetime	>10000 - 13000 cycles (20 – 40 years)	
Operational constraints	§ Below ground applications are restricted by availability of suitable sites and social acceptance § Above ground solutions in tanks is less restricted	
Installed capacity today	EU-28: ~ 0.6 GW	
Maturity	§ Low, only few (approx. 10) installations deployed in Europe and worldwide, approx.500 MW in total § Only two large scale plants exist in commercial application worldwide. However, these have been operational since decades (DE since 1978 and USA since 1991)	
Environmental effects	N/A	
Barriers	Technical barriers: Geographical barriers: salt caverns and aquifers are less capital intensive than aboveground solutions (e.g. tanks), but they require suitable sites. Economic barriers: High capital costs and long return on investment.	
Potential flexibility functions	Large-scale application for medium-term energy storage, time shifting	

Sources: [15], [4], [11], [11].

Flywheels

Flywheels store electrical energy as kinetic energy by increasing the rotational speed of a disc rotor on its axis. Flywheels are a fast-reacting energy storage technology with high power and energy densities, the possibility to decouple power and energy during the design, a large number of life cycles and are hardly dependent on external temperature. Flywheels such as Capacitors and SMES are of high power but low energy. Due to their fast response time and the low energy content, flywheels are best suited for frequency control and the provision of power quality.

Flywheels	Today	2030
Flexibility	Energy/power ratio (e.g. MWh/MW, discharge time) Minutes (5 – 30 Minutes)	
Efficiency	80-90%	
Investment costs	Depending on power and energy levels: 500-3000€/kWh; 1000-2000€/kW	
Variable costs	Unknown	
Lifetime	>100.000 cycles	
Operational constraints	See technical barriers	
Installed capacity today	Low, around 3 MW in EU-28	
Maturity	Moderate § Mature technology with more than 20 manufacturers in the market § Research needed to decrease manufacturing and equipment costs § Commercial projects especially in the USA but there are also projects in Spain, Portugal and Ireland	
Environmental effects	Low	
Barriers	Economic barriers: High investment cost Technical barriers: relatively high permanent 'self-discharge' losses, safety concerns (cracks occur due to dynamic loads, bearing failure on the supports), cooling system for superconducting bearings	
Potential flexibility functions	Flywheels are often used to provide inertia in island systems (first commercial plant built as recently as 2011 for large scale grid storage, and are well established in UPS systems). Applied most of all as short term storage with frequent and intensive cycling, often used for stabilisation for weak grids, i.e. inertia and frequency control, power quality.	

Sources: [12], [15], [16], [11].

Heat storage

Heat storage or thermal energy storage can be divided into three storage principles:

- Sensible heat storage stores energy by raising or lowering the temperature of a liquid or solid storage medium (e.g. water, sand, molten salts, rocks) for low-temperature applications. This is the most common form of thermal energy storage and has found commercial success on residential and industrial scales.
- Latent heat storage takes advantage of the energy absorbed or released at a specific temperature during a phase change of the material. In most cases, solid/liquid phase change is utilized, with melting used to store heat and solidification used to release heat.
- Thermochemical heat storage operates with both chemical reactions and sorption processes.

Sensible heat storage systems have comparably cheap operation and investment costs, but due to their low efficiencies their role as standalone electricity storage in the power system is limited. However, used together with CHP plants or as power-to-X they can provide relevant flexibility to the system. [12]
There are approximately 50 projects deployed worldwide, most of them in the U.S. and some in Spain.

Heat Storage	Today 2030
Flexibility	Energy/power ratio (e.g. MWh/MW, discharge time) § Hours to month(s) (Sensible HS) § Hours to few dates (Latent HS)
Efficiency	Up to 90%
Investment costs	§ Sensible heat storage cost of storage unit o Underground: 0.1 – 10€/kWh o Low temperature: 0.4 – 10€/kWh o High temperature: 15 – 70€/kWh § Latent heat storage cost of storage o Low temperature: 0.4 – 10€/kWh o High temperature: 20 – 70€/kWh § Thermochemical heat storage o Chemical reactions (target): 10 – 90€/kWh o Sorption process: 10 – 130€/kWh
Variable costs	Unknown
Lifetime	15 – 20 years
Installed capacity today	EU-28: ~0.2 GW
Maturity	§ Sensible heat storage: very mature for small-scale, single home systems; district heating systems are on a demonstration level. § Latent heat storage: o Commercialized for low-temperature, buildings, mini food and medical storages o Ice storages and aqueous salt solutions (<0°C): large-scale deployment o Other technologies such as salt hydrate and paraffin wax systems are partly commercialised o High-power systems remain in research and development with some demonstration projects, whereas high-capacity storages are in piloting and partly commercialization phase. Thermochemical heat storages remain largely in the research and development phase
Environmental effects	Low
Potential flexibility functions	Long-term (weekly and annual) flexibility

Sources: [12], [15], [16], [11].

Superconducting magnetic energy storage (SMES)

Just like capacitors, Superconducting magnetic energy storage (SMES) have very low energy contents and short discharge durations and are therefore used in the electricity system for short term applications such as provision of power quality and system stability. [12], [26]

Superconducting magnetic energy storage (SMES)	Today 2030
Flexibility	Energy/power ratio (e.g. MWh/MW, discharge time) Milliseconds to minutes
Efficiency	>95%
Investment costs	Unknown
Variable costs	Unknown
Lifetime	Practically unlimited number of cycles
Operational constraints	§ Still relatively high

	costs § Limited energy storage capacity § Low maturity	
Installed capacity today	Low	
Maturity	Low § First concept to use SMES in transmission system in the late 1970's § First commercial application of SMES was in 1981 § Low temperature SMES: several systems qualified through testing and demonstration, some commercial cases § High temperature SMES: prototype demonstration § Hybrid (SMES + other storage technologies): proof of concept	
Environmental effects	Low	
Barriers	§ Limited fields of application due to very short duration § Limited by production capacities (mostly out of Europe)	
Potential flexibility functions	§ Ancillary services	

Sources: [15], [16]

Appendix 2: Modelling approach of flexibility using the PRIMES-IEM model

A. Definitions

Operational flexibility signifies the ability of the power system to respond to both predictable and unpredictable changes in generation and demand in a way that meets reliability standards and avoids curtailments. In a system with high contribution by variable RES, three sorts of variability occur. Firstly, the largely unpredictable variations in short or very short time intervals. Secondly, the largely predictable daily multi-hour variability, as for example due to solar, or to also predicable variability over a few days due to meteorological conditions. Thirdly, extreme events, probably partly unpredictable, as for example the complete lack of renewable resources over a period, which challenges the reserves of the system.
Thus, the flexibility needs of a system require three types of flexible reserves, differentiated by their timeframe of response (from minute to minute up to multi-hour). Each flexibility reserve type calls upon different resources.

- Short-term flexibility (minutes): CCGT, GT, Hydro power plant with dam, batteries, demand response, pumped storage, interconnectors within the conventional ancillary services
- Mid-term (multi-hour) flexibility: directly by CCGT, batteries, pumped storage, interconnectors and indirectly by hydro plants with a dam and demand response
- Long-term flexibility (within a day, several days or seasonal): chemical storage meant by storage of hydrogen, heat, gas or liquids produced when electricity is in excess and used to generate electricity when needed or sold to the market in different periods.

The simulation of a power system to assess flexibility requirements and flexibility supply needs significant modelling resources, including:

- Hourly simulation over sufficiently large time intervals (this increases computing time)
- Mixed-integer optimization (this further increases computing time and makes the solution uncertain)
- Detailed representation of the power plants (individually) and the grid system , including the interconnections modelled with power flow methods (not transport methods)
- Inclusion of several storage technologies in the model
- Inclusion of modelling of water cycle for hydro plants and pumping
- Representation of stochastic variability and cyclical deterministic variability of RES

The simulations based on the PRIMES-IEM model use a dataset including system, plant and storage operation by hour in a future year. This dataset, produced as a projection output of the main PRIMES model, serves to quantify flexibility requirements and the supply of flexibility services (contribution of each type of resource to the coverage of flexibility requirements) by applying higher time granularity than in PRIMES, stochastic elements to capture unpredictable events and the sequence of daily markets and real time operation. The model simulates the operation of the power plants and storage facilities in the pan-European electricity systems as projected in a scenario and links the control areas with explicit modelling of power flows over the interconnectors. To represent plant scheduling realistically, the model mimics the sequential operation of wholesale and balancing markets on a daily basis (every day in a year), comprising the Day-Ahead market, the intraday market and the Balancing/Reserve market or procurement procedure. The market sequence modelling applies to a pan-European market and system, which operates over a network involving nodes (more than one for some countries) and interconnections where the power flows respect the two Kirchhoff laws. The sequence and design for each of these markets are consistent with the EU "Target Model" design, and eventual enhancements specified by reform policies as those included in the market design initiative of the winter package.

The simulation of the wholesale markets runs on an hourly basis per year until a certain horizon, such as the year 2030 in the applications simulating the effect of the recent market design overhaul initiative. The simulation takes as given the power plant capacities, the interconnection capacities, the demand for electricity and the load profile, the fuel prices and the carbon prices in the ETS, as well as the hourly production by the variable renewable energy plants. These inputs come from a projection using the PRIMES model for a certain scenario. The model takes also as inputs data and projections of the requirements for reserves and ancillary services. The model also uses functions, which associate quantities of demand response and costs.

PRIMES-IEM modeling steps		
	Starting Point: basic projection, including ETS prices, gas prices, variable RES developments, capacity expansion	
Operation of electricity markets, statically	1	Simulation of day-ahead market
	2	Simulation of the occurrence of random events between day-ahead projection and real time
	3	Simulation of real time unit commitment to determine deviations
	4	Simulation of the intraday market for upward and downward deviations
	5	Simulation of the reserves and ancillary services market or procurement
	6	Calculation of total revenues of power plants and present values in all the wholesale markets

Table 8: PRIMES-IEM modeling steps

Having as basis the EUCO scenario (used in the preparatory work for the Winter Package proposals), we measure the requirements and the supply of flexibility based on the hourly simulation results produced using the PRIMES-IEM following the modelling steps of *Table 8*. The steps also include the use of a "Random Events Generator" tool, needed to introduce random and unpredictable deviations between the Day-Ahead scheduling and the real-time operation of the system. The random event step enables us to take into account also the increased flexibility needs, caused by weather forecasting errors and deviations of resource availability from planned levels or changes in the demand.

The PRIMES-IEM formulations allows representing details of the market arrangements which may correspond to well-operating market, the eventually completed EU internal market, and also distorted cases to assess the impacts on flexibility requirements and supply conditions and the role of storage under various conditions.

For illustration purposes, in the present note we refer to two contrasted cases quantified, namely the cases 0 and 2.

- Case 0 is a business as usual projection for the internal market, where most of the distortions and current practices continue also in 2030.
- Case 2 is the maximum reform of the internal market aiming at removing all distortions, fully integrate the market and system operation and bring additional balancing resources from demand response and the participation of renewables.

B. Multi-hour flexibility metrics

Multi-hour flexibility requirements are defined as the variation of the net load caused by variable renewable generation or dispatchable generation sources, due to technical reasons, in a time interval, $\Delta h = 1 hour$. The impact of variable renewables is calculated as the hourly difference of the net load, where net load denotes the load after deducting the variable renewable generation and the CHP must-take generation[27].

$$Net\ Load_h - Load_h - vRES_h - CHP_h$$

$$Flexibility\ Demand_{netload,h} = NLDiff_h = Net\ Load_h - Net\ Load_{h-1}$$

where h denotes hours, $Load_h$ electricity load, $vRES_h$ variable renewable generation, CHP_h generation of must-take CHP plants.

Consider a time interval Δh in which net load ($Net\ Load_h$) is monotonically increasing. Normally the dispatchable generation sources should alter their hourly output level at the same direction as the net load difference between the ending and the starting point of the time interval. As the dispatching schedule is the result of a unit commitment algorithm, the schedule respects the technical operation restrictions (i.e. technical minimum, ramping rates, minimum up & down time, reserve requirements). They may differ from the scheduling of the pure energy market thus affecting the generation level of power plants, as this depends also on the provision of reserves and other system requirements. All the dispatchable power plants that have altered their generation opposite to the direction of the net load difference are part of the flexibility requirements, while the ones changing to the same direction are part of the flexibility supply.

Based on the results of the unit commitment algorithm (UC, Step 3), operated after the Day-Ahead Market (DAM, Step 1), the hourly difference of the output level for each power plant is calculated:

$$GenDiff_{g,h} = G_{g,h} - G_{g,h-1}$$

$$Flexibility\ Demand_{g,h} = \begin{cases} GenDiff_{g,h}, if\ (GenDiff_{g,h} > 0) \cup (Flexibility\ Demand_{netload,h} < 0) \\ -GenDiff_{g,h}, if\ (GenDiff_{g,h} < 0) \cup (Flexibility\ Demand_{netload,h} > 0) \end{cases}$$

where g denotes power plants and $G_{g,h}$ output level of each power.

The methodology discussed above for power plants also applies to imports/exports, as the modelling sequence represents a pan-European system and flows over interconnectors are fully endogenous taken into account technical constraints (interconnector capacities and Kirchhoff's laws). Thus, the hourly difference of net imports is calculated as:

$$NImpDiff_h = NI_h - NI_{h-1}$$

$$Flexibility\ Demand_{NI,h} = \begin{cases} NImpDiff_h, if\ (NImpDiff_h > 0) \cup (Flexibility\ Demand_{netload,h} < 0) \\ -NImpDiff_h, if\ (NImpDiff_h < 0) \cup (Flexibility\ Demand_{netload,h} > 0) \end{cases}$$

where *NI* denotes net imports power plants and $G_{g,h}$ output level of each power.

The total amount of flexibility requirements is the sum of the flexibility requirements attributed to the various origins.

[27] It is assumed that industrial CHP units and exclusively district heating plants dispatch with priority, as their generation is mainly affected by the steam/heat demand. PRIMES-IEM does not represent explicitly the demand and supply of heat, thus their electricity output level is deducted when calculating net load.

$$Flexibility\ Demand = \sum_h \left(Flexibility\ Demand_{netload,h} + \sum_g Flexibility\ Demand_{g,h} + Flexibility\ Demand_{NI,h} \right)$$

The power plants and other providers (i.e. storage, interconnectors, and demand response) have to cover the flexibility requirements. The metric of flexibility supply result from the unit commitment schedule, as a calculation of the ramping service power (RSP – see below). Given the commitment cycle of a plant defined by the technical operating restrictions, the amount of time the plant is committed at minimum stable generation (or else Ramping Available Power – RAP) is necessary to enable the a flexibility service provision later on. Within the same commitment cycle, if the plant scheduling includes ramp-up or ramp-down generation at a ramp rate above a pre-defined minimum threshold, (of course below the plant's maximum ramping rate) then the calculation includes the ramping as a ramping service, otherwise it is a simple load following operation and not a special ramping service offered to the system. The minimum threshold practically excludes the power plant technologies that are largely inelastic for ramping.

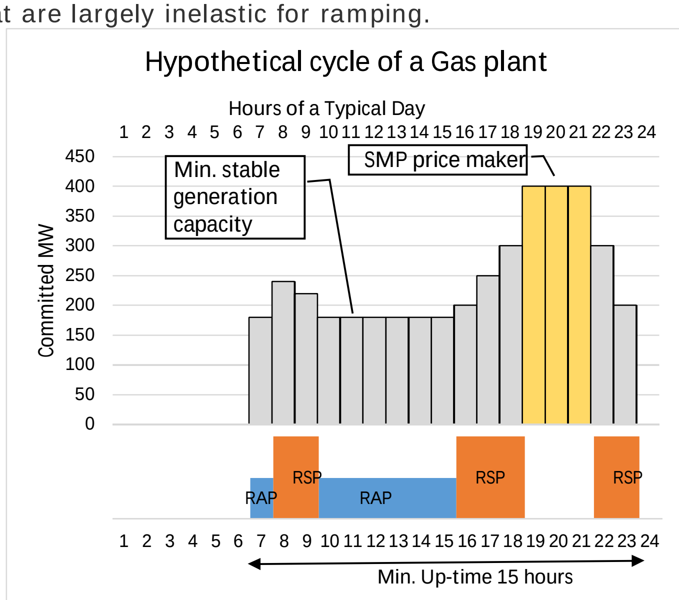

Figure 25: Typical Cycle of a CCGT

Figure 25 shows commitment of a typical CCGT plant as resulting from the unit commitment algorithm running after the day ahead market. The plant is committed to synchronize on a minimum stable generation level at 7th hour, and perform a sequence of ramping and commitment at minimum stable generation level, except at hours 19 to 21 when the plant (or another gas plant) is an SMP price maker. The figure illustrates the distinct times of RAP and RSP. Notice that between 19 and 21 hours none of RAP or RSP applies as CCGT is an SMP price maker. Over the periods of RAP and RSP other plants (i.e. more likely base load plants) with lower economic bids than marginal costs of CCGT are the SMP price makers. The flexibility service provided by the plant is defined as the ramping power (MWh) produced during RSP hours. Due to the minimum up-time constraint, the power plant has to remain at minimum stable generation level over the RAP hours. Between 19 and 21 hours, when a gas plant is price-maker, the gas plant illustrated in the figure operates at a stable level above minimum stable level and does not provide flexibility services.

The RSP or flexibility supply is then calculated as the ramping, measured in MWh, of power commitments which increase or decrease, respectively for ramp-up and for ramp-down, excluding time intervals during which the plants remains at a certain unchanged power level and during which the ramping of the power plants is on the opposite direction of the net load change.

$$Flexibility\ Supply_{g,h} = \begin{cases} GenDiff_{g,h}, if\ (GenDiff_{g,h} > 0) \cup (Flexibility\ Demand_{netload,h} > 0) \\ -GenDiff_{g,h}, if\ (GenDiff_{g,h} < 0) \cup (Flexibility\ Demand_{netload,h} < 0) \end{cases}$$

The same calculation applies also for the net imports

$$Flexibility\ Supply_{NI,h} = \begin{cases} NImpDiff_{h}, if\ (NIDiff_{h} > 0) \cup (Flexibility\ Demand_{netload,h} > 0) \\ -NImpDiff_{h}, if\ (NIDiff_{h} < 0) \cup (Flexibility\ Demand_{netload,h} < 0) \end{cases}$$

For storage plants and demand response, the whole quantities of supplied electricity are part of the flexibility provision. These resources typically do load shedding or shifting thus enabling reduction of flexibility requirements. As both storage and demand response are fully endogenous in the model, they become economic because they provide flexibility services, otherwise the system does not need them.
The total amount of flexibility supply is the aggregation of the individual flexibility supplies by each type of power plant/provider.

$$Flexibility\ Supply = \sum_{h}\left(\sum_{g} Flexibility\ Supply_{g,h} + Flexibility\ Supply_{NI,h} + Storage\ Extraction_{h} + Demand\ Response_{h}\right)$$

C. Intraday balancing model

Short-term flexibility metrics rely on the simulation of the intra-day balancing model and the procurement of spinning secondary reserves.
The intraday and Balancing Market (IDBM, Step 4) simulates a stylized hourly market for the deviations that occur between the Day-Ahead market and the unit commitment algorithm, the latter running after the random events generator to simulate the real-time system requirements. These random events, generated using the Random Events Generator (Step 2), include load and RES generation forecasting errors, outages of plants and interconnectors, and others considered as causes of deviations. Deviations also occur because the scheduling derived from a pure energy market, as in the Day-Ahead, may not be optimal when including the technical restrictions of plant operation and the various system reserves. The scheduling derived from the Day-Ahead energy-only market rely in the economic bids submitted by generators who may have ignore the cyclical operation constraints of dispatchable plants and the resources required to meet the ancillary services. Within a perfect market, one could postulate that the generators-suppliers are clever enough to prompt on the plant restrictions and system ancillary services and thus submit optimal block orders and bids in the Day-Ahead to avoid any exposure to imbalances costs in the intra-day markets. However, this can never be the reality for many reasons. Therefore, the modelling using the PRIMES-IEM includes options regarding the degree of optimality of the bidding in the Day-Ahead with respect to potential deviations. The options span a range between bidding per plant with full ignorance of technical restrictions and system reserves and the case of perfectly optimal bidding, as if the players where co-optimizing energy costs and technical restrictions and ancillary services. The simulator of the intra-day markets

performs a single-shot market clearing of the deviations, i.e. it does not simulate sequential intraday markets.

Comparing the Day-Ahead and the unit commitment solutions, deviations occur due to the consideration of technical constraints of plants in the unit commitment model and due to other variations of load and renewables generation as included in the experiments produced using the Random Event Generator. Before settling these deviations financially, the Intra-Day and Balancing simulator uses a set of rules to determine which resources are eligible to bid in the Intra-Day and Balancing to meet the deviations. All the dispatchable[28] power plants that have altered their generation from the Day-Ahead solution to the unit commitment solution opposite to the direction of load deviation form a group that splits into two subgroups, one for every direction of the load deviation. If the load in the Day-Ahead simulation is lower than the one in unit commitment and the generation of the unit is higher in the Day-Ahead simulation than in unit commitment, the unit cannot offer to meet upward deviations. If the reverse is true, the unit cannot offer to meet downward deviations. The logic behind this is that these plants are not load following in the unit commitment solution due to technical reasons, and thus should not be able to contribute in covering intraday deviation. Hence, the rest of the dispatchable plants can submit offer to meet the deviations between Day-Ahead and unit commitment. The dispatchable power plants can offer their capacity to the IDM (including demand response), except the capacities that are part of the schedule to meet the reserve and ancillary services market according to the unit commitment solution. To meet upward deviations, the eligible capacities can offer the remaining unused capacity above the level committed following the scheduling issued by the Day-Ahead, minus commitments for upward reserve procurement. Similarly, to meet downward deviations, the eligible capacities can offer to reduce the capacity below their level in the scheduling issued by the Day-Ahead up to the minimum stable generation level and after taking into account the capacity qualified for downward reserves. The hydro generators with a reservoir, in particular, can offer energy only up to the maximum difference between Day-Ahead and unit commitment solution, either upwards or downwards. Units not dispatched in the Day-Ahead solution can perform a start-up, if suggested so by the results of the optimization. Along the same lines, the optimization can force units dispatched in the Day-Ahead solution to shut down. Start-ups and shutdowns are possible only for plants that have minimum shutdown or start-up times that the system can accommodate when scheduling the adjustments for addressing the deviations. Power plants having operation constraints making them inflexible are not eligible for shutdowns or start-ups. In addition, none of the plants can offer energy that violates the ramping possibilities and the other technical restrictions, such as the minimum up and down times.

The modelling of flows over the interconnections uses DC power flow in the context of the Intra-Day market, as in the Day-Ahead. Depending on the Case, it is possible by assumption not to include the participation of cross-border offers in the Intra-Day market. In the Case 2, in which we assume market coupling also in the intraday and balancing markets the models solve a flow-based allocation under restrictions due to the net transfer capacity factors.

D. Reserves and ancillary services

The simulation of the reserves and ancillary services market or procurement (Step 5) assigns plant capacities to the provision of ancillary services, to meet requirements for reserves when co-optimizing energy and reserves. In the simulation all 4 types of reserves, according the pan-European harmonized terminology of ENTSO-E (i.e. FCR,

[28] We define as dispatchable all the thermal power plants that are controllable by the scheduling defined by the system operator, including conventional thermal plants and hydroelectric plants.

a-FRR, m-FRR, RR) are included. Nevertheless, we have used only the automatic Frequency Restoration Reserve procurement for the short-term flexibility calculations. The logic behind this is that this type of reserve is the most important one, to cope with the variability and uncertainty of variable renewable generation. As also ENTSO - E report mentions, the methodology for Reserve Dimensioning for FRR type is mainly influenced by short-term forecast errors, unit outages etc.

Automatic Frequency Restoration Reserve (a-FRR) is activated after the Frequency Containment Reserve (FCR) and modifies the active power set points/ adjustments of reserve providing units in a timeframe of seconds up to typically 15 minutes after an incident, using automation generation control (AGC).

In Case 2, where markets for ancillary services are liquid, we assume that RES participate in the market for downward reserves. In addition, as market integration is complete, we assume that cross-border resources are fully eligible to participate. Their contribution is subject to limitations arising from the availability of interconnection capacities, which are the remaining capacities after taking into account the scheduling of interconnection flows in the intra-day balancing market.

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