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Flexibility options in electricity systems

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Summary

It is widely recognised that increasing flexibility is key for the reliable operation of future power systems with very high penetration levels of variable renewable energy sources (VRES). The starting point of this report is the understanding of the flexibility requirements for enabling the transition to such power systems. Furthermore, this report aims in providing a comprehensive assessment of the complete spectrum of flexibility options (instead of focusing on specific ones) and to identify key barriers for their deployment.

Flexibility is the ability of a power system to maintain continuous service in the face of rapid and large swings in supply or demand. Traditionally, flexibility was provided in power systems almost entirely by controlling the supply side. In systems with increasing shares of VRES, additional flexibility is needed to maintain system reliability as the variations in supply and demand grow to levels far beyond what is seen today. VRES reduce the flexibility resources in the system by displacing traditional supply side flexibility providers while simultaneously increasing the need for flexibility due to their inherent stochastic nature. This creates a "flexibility gap" that will need to be covered by new flexibility options.

Variability impacts all different power system operational timeframes. A transformation of power system operational planning is expected. The question of having sufficient resources to meet demand is changed to having sufficient flexibility resources to balance net demand forecast errors and fluctuations. By increasing VRES penetration levels, the impacts to more long-term timeframes become more visible. This affects the choice of suitable flexibility options: in shorter timeframes, response times are of more importance; in longer timeframes, the ability to offer large storage content and long shifting periods would be of more importance.

Power systems should deploy the most economic resources for provision of energy and operational flexibility. New flexibility resources will compete with flexibility capabilities of the existing system, such as network expansion, existing supply flexibility. In this report, a detailed analysis of the characteristics of the key flexibility options is presented. We analyse 16 options covering five key categories of flexibility provision, i.e. supply, demand, energy storage, network and system.

The results show that different flexibility options are best suited to different operational timeframes. The variety of options show that there are several options to consider in each timeframe. As expected, the main mature options are on the supply side; on the demand side, a key mature option is the large-scale industrial demand response, while pumped hydro is the main mature storage technology. Most of the new demand and storage options are small scale technologies. The development of these options depends on the enabling communication and control infrastructure, which for such small scale units will represent a relatively higher share of costs. In the long run, only one storage technology competes with thermal power plants (however in the expense of high losses): Power to gas. For systems with higher VRES shares, more sophisticated control of VRES can be a more cost effective opportunity for providing system flexibility (or alternatively, reducing the needed flexibility).

This option however faces institutional, perceptual, and potentially political challenges due to the perception that renewable energy is being wasted.

Specific market barriers are identified, which may hinder the development of flexibility options. A key difference is that investments in supply options are driven by high market prices, while market price variability (spreads) is an indicator for investments in flexibility. However, market prices and spreads are related to each other, making any intervention on the supply side having impact to the other options. In markets with overcapacities, market price variability is reduced. Therefore, the incentives for flexibility are removed. Making future markets provide sufficient incentives for peaking capacity and flexibility is a key challenge towards systems with higher VRES shares. Furthermore, one main barrier to demand management is a lack of systems and incentives for loads to participate in power system operations. Smart metering infrastructure could boost the prospects for residential and commercial demand management. Finally, reviewing the prequalification standards in markets could open additional markets to new flexibility options and to VRES (e.g. reduction of minimum bid sizes, shorter scheduling periods and reduction of gate closure times).

Table of contents

1	**Definition and need for flexibility**	**1**
1.1	Definition of flexibility	1
1.2	Need for flexibility: Impact of variable renewables	2
1.2.1	VRES impact on increasing the need for flexibility	3
1.2.2	VRES impact on the reduction of system flexibility resources	4
1.3	The flexibility timeline: Challenges for VRES integration	5
2	**Fact sheets on flexibility options**	**8**
	Flexibility in Fossil generation	10
	Nuclear power plant flexibility	13
	Biogas power plant flexibility	15
	Flexibility in combined heat and power	17
	Active power control of renewable energy	19
	Demand management in industrial installations	21
	Demand management in services and households	22
	Electric vehicles	23
	Power to Heat	24
	Pumped hydro storage	26
	(AA-) CAES	27
	Flywheels	28
	Batteries	29
	Power to Gas	31
	Market options to uncap flexibility	32
	Network options to increase flexibility	34
3	**Mapping of flexibility options**	**36**
3.1	Mid-Term Flexibility	37
3.2	Short-Term Flexibility	38
3.3	Long term flexibility	38
3.4	Market barriers	38
4	**Conclusions and Recommendations**	**41**
5	**Literature**	**43**

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1 Definition and need for flexibility

It is widely recognised that increasing the flexibility of power systems is key for the reliable operation of future power systems with very high penetration levels of variable renewable energy sources (VRES). The starting point of this report is the understanding of the flexibility requirements for enabling the transition to such future power systems.

1.1 Definition of flexibility

Power system flexibility is an inherent feature in the design and operation of power systems. Power systems are designed to ensure a spatial and temporal balancing of generation and consumption at all times. Power system flexibility represents the extent to which a power system can adapt electricity generation and consumption as needed to maintain system stability in a cost-effective manner. Flexibility is the ability of a power system to maintain continuous service in the face of rapid and large swings in supply or demand.

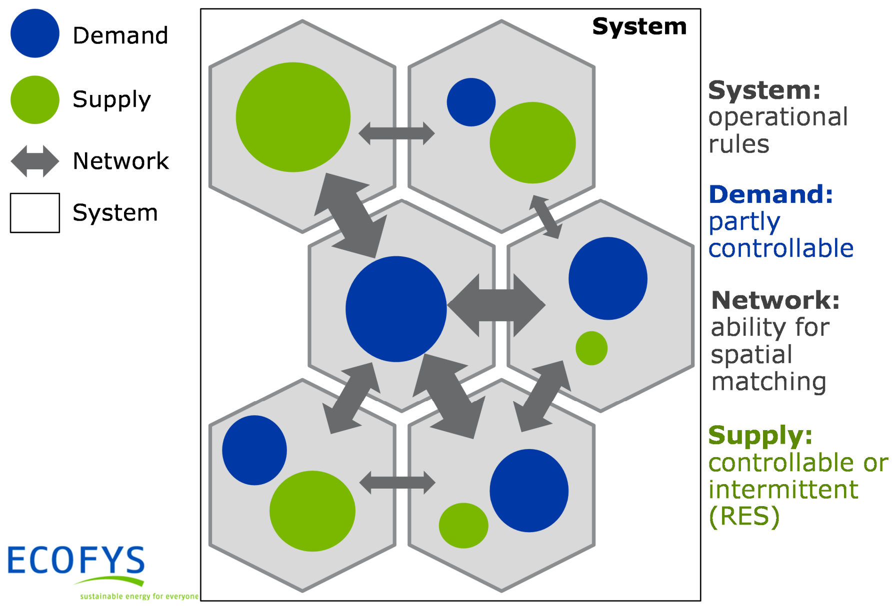

Figure 1: Schematic representation of the power system operational principle.

Flexibility services include "up regulation" that provides additional power as needed to maintain system balance, and "down regulation" that reduces the power generation in the system. Both up regulation and down regulation can also be supplied by controllable loads—up regulation provided by reducing load, and down regulation from increasing load. Contingency (short-term) reserves are required for ensuring power system stability in the event of large power system component outages. Ramping capability is an expression of how fast flexible resources can change demand or supply of power.

1.2 Need for flexibility: Impact of variable renewables

Power systems are comprised of power sources (supply) and sinks (demand) which are geographically spread and are connected through the power network and their operation is defined based on a set of system rules (see Figure 1). Traditionally, flexibility was provided in power systems almost entirely by controlling the supply side. Two key tasks for the power plant fleet was to follow all variations in the demand (variability) and to ensure that the system stays in balance in the case of the sudden loss of a generating unit (uncertainty). Thus, variability has historically been an issue primarily related to demand, while uncertainty was an issue primarily related to supply. In this respect, ramp rates, minimum up/down times, and start-up/shut-down times are commonly used indicators of flexibility, measured as MW available for ramping up and down over time. Power networks are key enablers of flexibility, since they define the spatial dimension of balancing and thus the extent to which flexibility resources can be shared between adjacent areas. Finally, the system operational rules define how flexibility resources are utilised on day-to-day operation.

The introduction of variable renewable energy sources (VRES) such as wind and solar energy will add to the need for power system flexibility:

a. VRES increases supply side variability and uncertainty, **increasing the need for flexibility**
b. VRES displaces part of the conventional generation capacity, tending to **reduce the availability of flexible resources on the system**.

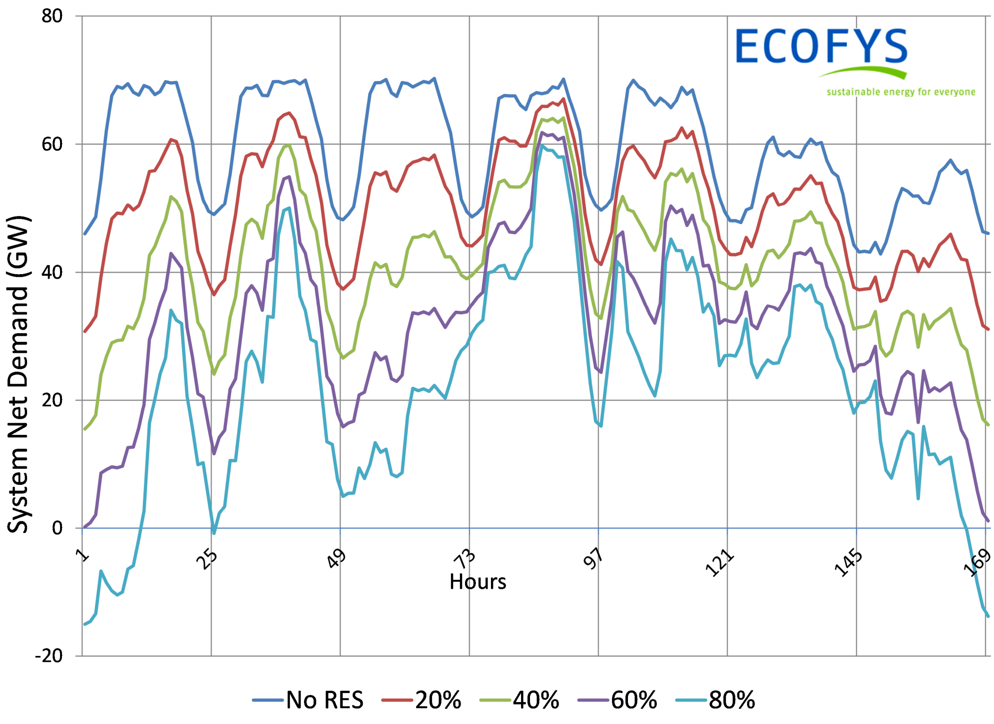

Figure 2: Daily patterns of electricity demand (No RES) and net electricity demand (different penetration levels). Source: Own analysis for Germany.

1.2.1 VRES impact on increasing the need for flexibility

For systems with increasing shares of VRES, the conventional power plant fleet must follow the variations of the net demand. Net demand is the demand minus variable generation. Depending on the VRES penetration levels, the net demand can have significantly different properties than demand alone, presenting higher variability and different ramping patterns, which leads to higher flexibility needs. This can be seen in Figure 2, where the demand and the net demand for different VRES penetration levels for the German system are presented. The net electricity demand changes with increasing VRES penetration levels, exposing the system operation to higher ramps and constantly changing demand patterns.

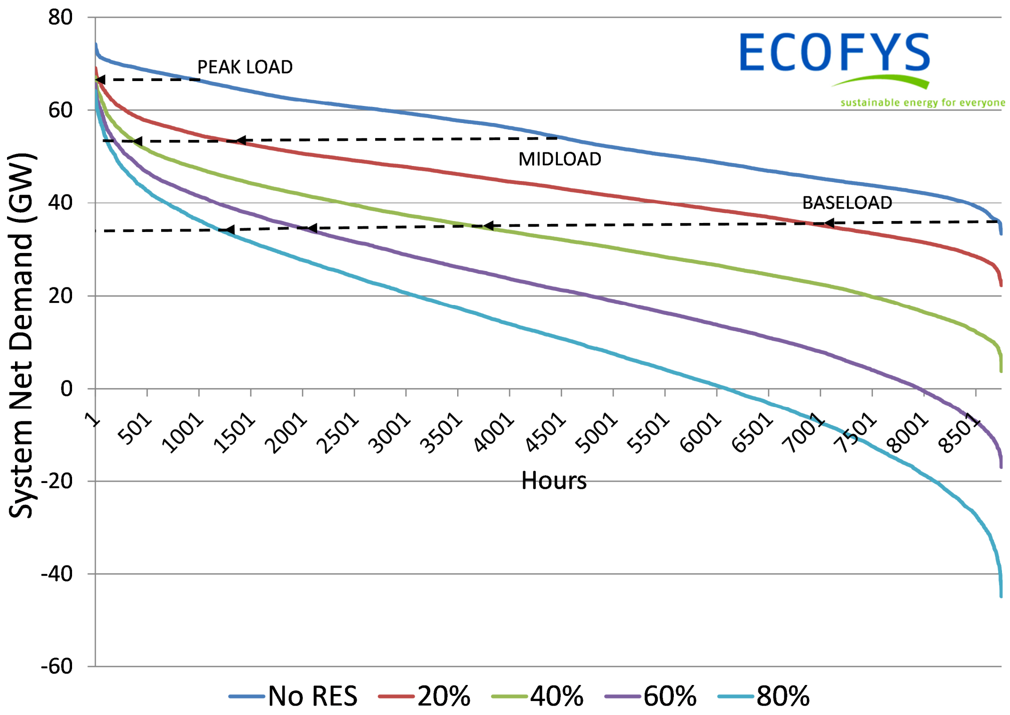

Figure 3: Dynamic range of electricity demand (No RES) and net electricity demand (different penetration levels). Source: Own analysis for Germany.

Figure 3 presents the system net demand duration curves for the system operation for a period of a year. The figure shows the large increase of variability in net demand with increasing VRES penetration levels, depicted by the expanded operational range. A key consequence is that the capacity factor[1] of conventional generating units is radically reduced, as indicated by the horizontal dashed lines. With high VRES shares, the system should operate under significant oversupply events (negative net

[1] Capacity factor of a power plant is the ratio of its actual output over a period of time, to its potential output if it was operating at full nameplate capacity.

demand). In these cases the system demand should be increased, or the excess of energy should be transported to adjacent areas, or stored for later times.

The range of hourly ramps of net electricity demand is presented in Figure 4. The graph shows how the operational variability (and thus the balancing requirements) is radically increased with higher VRES shares.

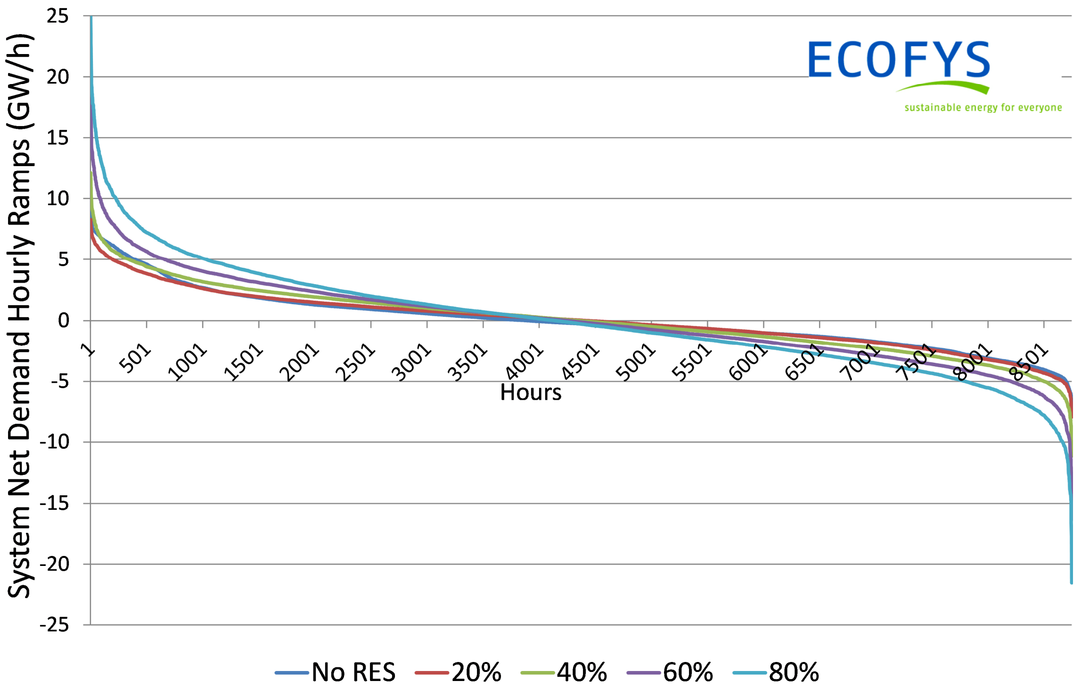

Figure 4: Hourly ramping range of electricity demand (No RES) and net electricity demand (different penetration levels). Source: Own analysis for Germany.

1.2.2 VRES impact on the reduction of system flexibility resources

Traditionally, peaking units are the most flexible units in the system and are responsible for the largest share of the system's flexibility. VRES have a direct impact on the profitability of such units due to the reduction of their capacity factor. This reduction of the duration of peak demand can be seen clearly in Figure 3: although the peak demand is not reduced significantly, the net demand duration curves are steeper in peaking hours, showing a radical decrease in the operational hours peaking units.

The impact of VRES on reducing power system flexibility is already visible. An example is presented in Figure 5, based on the operation of the German system for one week in February 2011 (ex-post data). Peaking plants were shut down in response to the high wind generation during the demand valley from Friday night through Saturday morning. In addition, baseload units (nuclear and lignite) were operated at minimum generation levels and exports were at high levels. The high wind generation resulted in high flexibility needs as well as low and negative power prices, that drove flexible peaking units off line.

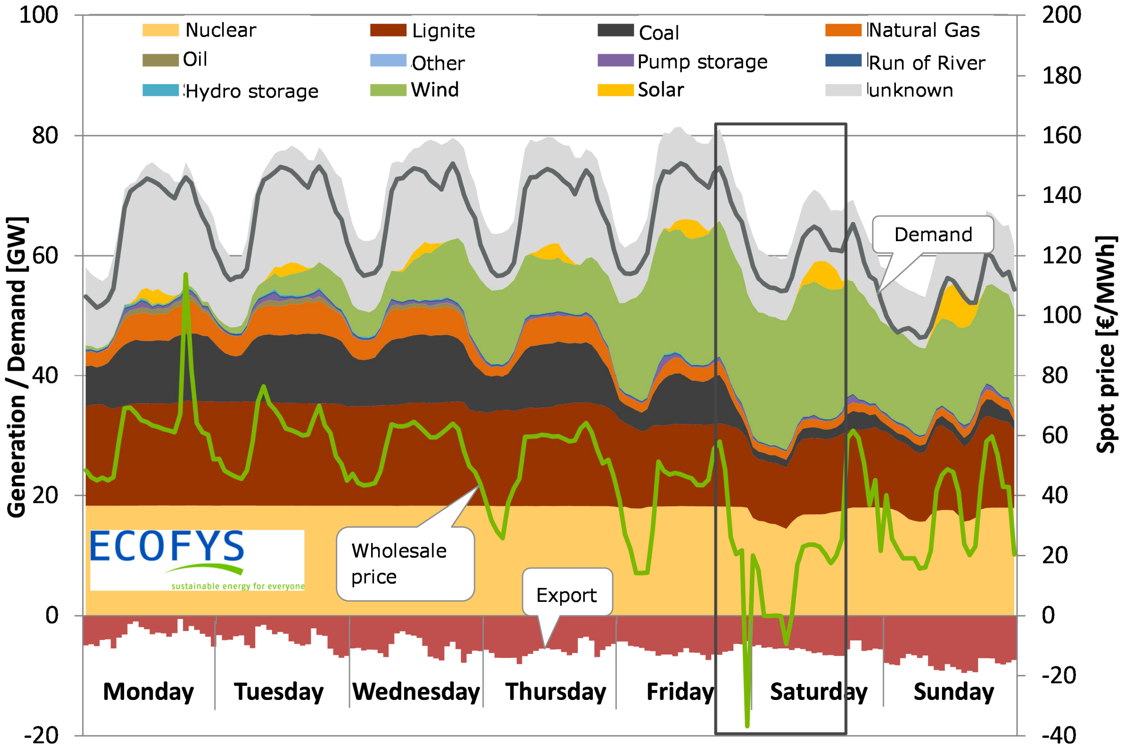

Figure 5: VRES impact on the reduction of system flexibility resources. Source: Own analysis based on EEX, ENTSO-E

This is a prime example of VRES increasing the need for flexibility in the system, while simultaneously displacing the traditional flexibility resources. This dual impact calls for revisiting of the system operation, to ensure the provision of sufficient flexibility resources needed to maintain system stability and security. Flexible power plants should remain online and be prioritized against less flexible (but cheaper) power plants. This suggests that changing the dispatch order (e.g., shutting down baseload plants before shutting down more flexible resources) may be a more cost-effective option than building additional flexible resources.

1.3 The flexibility timeline: Challenges for VRES integration

Understanding the impact of variability on different operational timeframes is necessary to comprehend the flexibility requirements for systems with higher VRES penetrations. Figure 6 illustrates a flexibility timeline with typical system planning stages.

Traditional power system planning focused on ensuring system adequacy in terms of sufficient generating capability to meet peak demand and energy consumption. Adequacy for systems with high VRES penetration will require greater emphasis on ensuring sufficient flexibility. The seasonal behaviour of VRES 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.

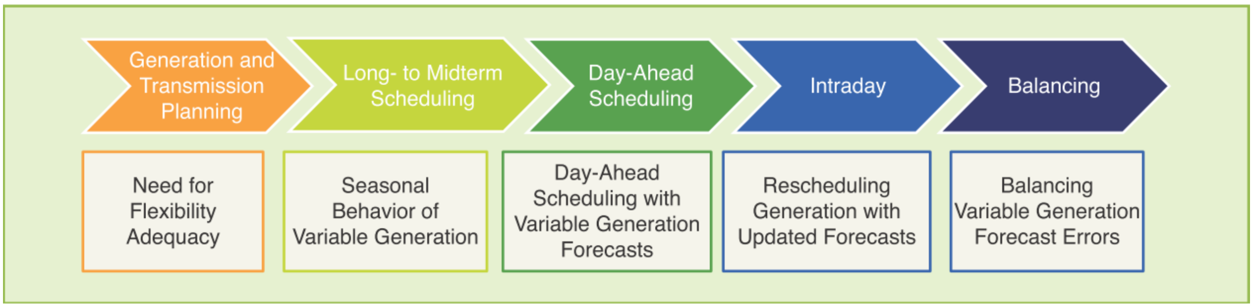

Figure 6: Impacts of VRES on the flexibility timeline, Holttinen (2013)

The need for long-term flexibility options is increased with increased VRES penetration levels. For low VRES penetration levels, impacts are mainly visible in the shorter timeframes (operational flexibility, provision of balancing capability). The key characteristics for the choice of suitable flexibility options in this case are response times, e.g. ramping capability. As shown in Figure 6, very high VRES shares impact long-term planning, e.g. need for seasonal energy storage to accommodate seasonal oversupply. Technologies that can offer large storage content and long shifting periods are important for this. A schematic representation of this concept is presented in the figure below for the case of energy storage, where the significance of different flexibility characteristics is presented with regard to the different planning timeframes.

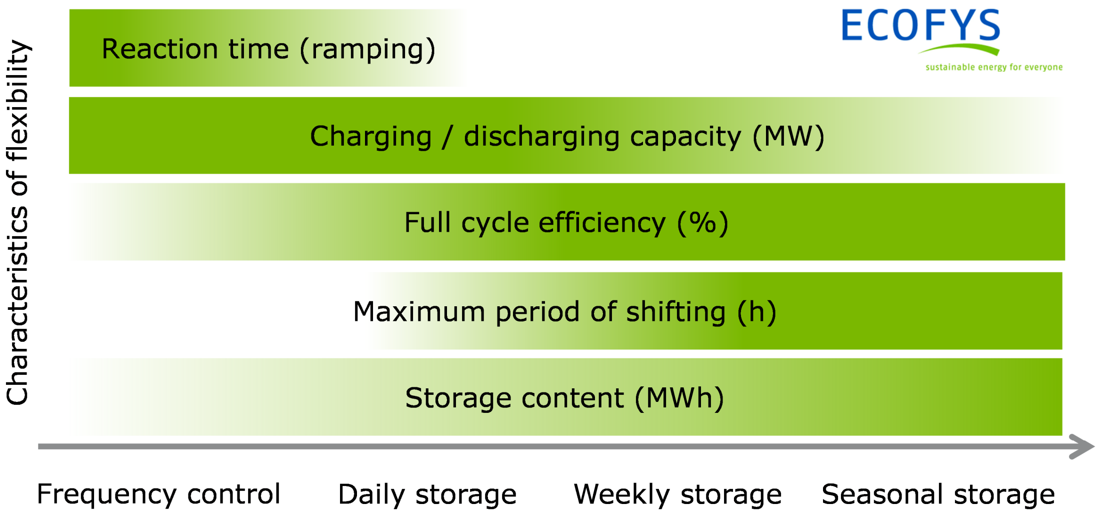

Figure 7 Basic characteristics of energy storage for providing flexibility and their significance in the different timeframes

In European electricity markets, these timeframes are reflected in different markets: Balancing markets cover short-term imbalances, daily differences are taken into account on spot markets, while long-term contracts are traded in future markets. Below, we discuss shortly how flexibility is traded in these markets

Short term flexibility for imbalances

On the imbalance market, reaction time is the most important characteristic. Balancing on timescales of less than 5 minutes must be done automatically because there is not sufficient time to arrange market trades of power that quickly. In the European electricity system, balancing markets are generally applicable for imbalances in the time-frame of up to one hour. Primary balancing energy covers the first seconds, until secondary balancing joins in. Tertiary balancing energy covers the imbalances between 15 minutes and one hour.

Middle term flexibility on sport markets

Wind and PV are traded on spot markets. They include day-ahead and intraday bids and offers. Gate closure times have an influence on the markets of imbalance –forecasts for secured capacity becomes more accurate when trade is close to the fulfilment period. Liquid intraday markets reduce the demand for balancing energy.

Long term flexibility

Energy can be traded years in advance. These contracts rely on estimated variable costs of production and add a risk premium. VRES cannot take part in these markets, unless they are backed-up by conventional power plants or storage.

Power systems should deploy the most economic resources for provision of energy and operational flexibility. New flexibility resources and technologies developed to meet flexibility needs will compete with flexibility capabilities of the existing system, such as network expansion, existing supply flexibility. The optimal options for new flexibility will depend on specific power system conditions. In the following section we provide a categorisation of the flexibility options in order to map the different solutions that are available to system planners.

2 Fact sheets on flexibility options

The categorisation of flexibility options is presented in Figure 8, based on five basic flexibility categories:

1. **Supply** ("something-to-electricity"): Power plants have traditionally provided nearly all system flexibility. Flexibility options in power supply include conventional generation systems (coal, gas, oil, biogas, CHP and nuclear) but also flexibility provided by VRES.

2. **Demand** ("electricity-to-something"): Flexibility options in demand side are significant. Demand management programs take advantage of new capabilities in communication and control, enabling two-way communication with loads as small as 5 kW. Such options, including demand management in electricity sector (energy intensive industries, services and smart applications) and options that come from the electrification of other sectors, as electric vehicles and heat pumps and water heating.

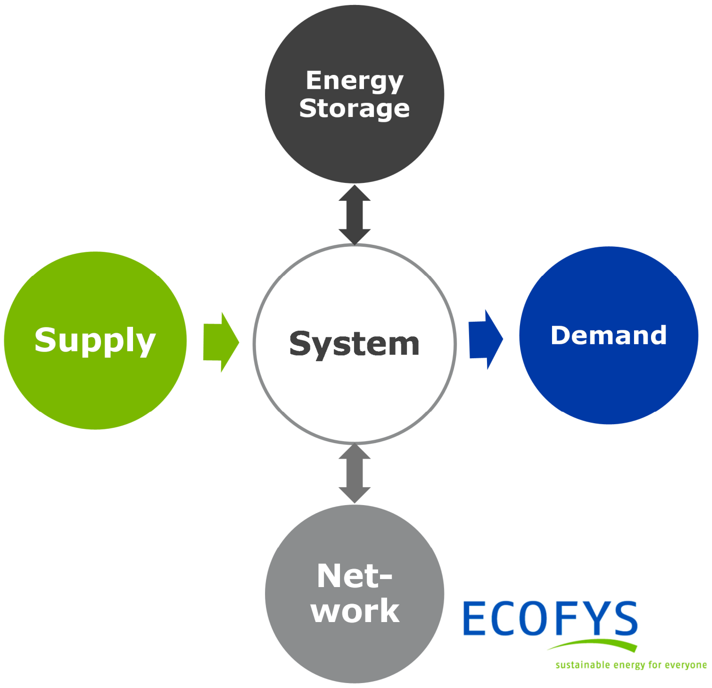

Figure 8: Categorisation of system flexibility options

3. **Energy Storage** ("electricity-to-something-to-electricity"): Energy storage can be seen as both generation and demand in the system, allowing the time-shifting of energy between periods of over- and under supply from VRES. Key options here are pumped storage, (AA-) CAES, flywheels, batteries, as well as hydrogen and its successor power-to-gas.

4. **Network**: 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 VRES 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).

5. **System**: Improvement of the system operation principles can be highly beneficial for better VRES integration and for uncapping the flexibility resources of the system. Key options here is the tuning of market operation rules (e.g. reducing gate closure times) and improving market integration by the expansion of market and control zones (which in turn will allow effective reduction of VRES variability due to spatial aggregation).

The flexibility potential of options belonging to the three first categories is easier to quantify, by exploring the flexibility characteristics of the related technologies. The potential of options belonging to the last two categories depends on the characteristics of the specific system and is therefore strongly case specific.

In this section we present the characteristics of the key flexibility options. The technological characteristics of the options referring to the three first categories are presented more quantitatively, while the options in the last two categories are presented in a more qualitative manner.

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Flexibility in Fossil generation

Fossil generation refers to power plants that use fossil fuels for generation, namely coal, gas and oil. The key technologies are steam turbines, gas turbines, combined cycle gas turbines and internal combustion engines. Steam turbines use the dynamic pressure generated by expanding steam to turn the blades of a turbine. Gas turbines (Open Cycle Gas Turbines - OCGT) use the expansion of combustion gases to directly power the turbine. Combined cycle gas turbines (CCGT) have both a gas turbine fired by natural gas, and a steam boiler and steam turbine, which uses exhaust gas heat from the gas turbine to create steam that powers a steam turbine. Internal combustion engines (ICE) use reciprocating pistons to convert pressure into a rotating motion and generate electricity. ICE are often used for power production in isolated systems (islands) as well as for emergency back-up capacity, e.g. in hospitals.

Supply

Key flexibility constraints come from the technical restrictions of each technology, defined by its ramping capability, must-run requirements and minimum load. Technology developments in power generation and refurbishment of old units can allow increasing the flexibility of thermal generation. With increasing shares of VRES, thermal generation takes the role of back-up capacities to cover the variability of net demand.

Efficiency	Coal: up to 48%, Lignite: up to 44%, CCGT: up to 60%, OCGT: up to 40%, ICE: up to 45%	**Reaction time**	Ramping: Existing power plants: coal: 1,5 %/min, lignite: 1%/min, CCGT: 2%/min, OCGT: 8 %/min, ICE: 100 %/min technically feasible: coal: 4%/min, lignite: 2.5 %/min, CCGT: 4 %/min, OCGT: 12 %/min, new installations: coal: 6 %/min, lignite: 4 %/min, CCGT: 8 %/min, OCGT: 20 %/min Cold start: existing power plants: coal: 10 hours,

			lignite: 10 hours, CCGT: 4 hour, OCGT: <0.1 hour, technically feasible: coal 5 hours, lignite 8 hours, CCGT 3 hours, retrofitted and new power plants: coal: 4 hours, lignite: 6 hours, CCGT: 2 hours
Investment costs	New coal power plants: 1300 – 1750 €/kW, New lignite power plants: 1600 – 1850 €/kW, New CCGT: 684 – 1250 €/kW, New OCGT: 380 – 700 €/kW, New ICE: 140 – 300 €/kW	**Variable costs**	Highly dependent on fuel costs. Price indications for the current European market: Coal: 22 – 30 €/MWh, Lignite: 3 – 5 €/MWh, CCGT: 40 – 60 €/MWh, OCGT: 60 – 76 €/MWh, ICE (diesel): 260 €/MWh In the EU, additional CO2 costs have to be included. Cold starts costs: Coal: 78 – 110 €/MW, CCGT: 60 €/MW, OCGT: 24 €/MW,
Installed capacity	EU-27: ~440 GW	**Minimum load**	Coal: 20 – 40%, CCGT: 15 – 50%, OCGT: 20 – 50%
Lifetime	Coal: 35 – 45 years, Lignite: 45 years, CCGT: 30 – 40 years, OCGT: 25 – 50 years	**Maximum energy content / Maximum period of shifting**	N/A
Maturity of technology	High: flexibility is increasingly implemented, also in base-load technologies like lignite power plants		
Environmental effects	Ramps and part-load operation lead to lower efficiencies and higher CO_2-emissions. Starts and ramps also lead to increased wear and tear on the unit components and systems.		
Barriers	Economic barriers: High investment costs, increasing variable costs when used		

	in flexible operation Technical barriers: endurance of materials in flexible operation, new technologies can cause new problems (e.g. cracks in T-24-steel that prevented several power plants from operation in 2011) Political barriers: new thermal power stations and heavy emitting technologies like coal and lignite often lack public support
Potential role	Traditionally, fossil generation has been responsible for providing flexibility in power systems. Based on the flexibility potential of each technology, power plants are categorised as base load (inflexible but cheap), load following (can adapt to daily/weekly variations of load but are more expensive) and peaking (flexible but the most expensive units). Gas turbines and internal combustion engines are the most flexible units, while CCGT and steam turbines are subjected to more constraints. With increasing shares of VRES, thermal generation takes the role of balancing the the variability of net demand.

Nuclear power plant flexibility

Supply

Nuclear power stations use heat generated by fission in a nuclear reactor to drive steam turbines. Most of the European nuclear power plants use pressurised water reactors (PWR), which use the heat from the core to heat water under high pressure that feeds a heat exchanger ("steam generator") to boil water in a separate piping system to power the steam turbine. Another key technology is boiling water reactors (BWR) where steam is generated directly in the reactor core. In UK, additionally advanced gas cooled reactors use gas for heating the water.

Nuclear power stations are mainly used as base load units and are highly inflexible. However, literature shows that PWR can ramp down to 20% of their installed capacity, but this flexibility is rarely used because the variable (e.g. fuel) costs are very low and savings from reducing output are small.

Nuclear power is highly controversial because the intrinsic risks of a large-scale accident and the issue with nuclear waste disposal. A number of countries decided to phase out the existing installations, especially after the meltdown of nuclear power plant facilities in Fukushima, Japan. Some other countries investigate whether flexibility from Nuclear can support Nuclear/VRES base for CO2-free systems.

Efficiency	32 – 33%	**Reaction time**	3,8 %/min in part load – 10 %/min at maximum capacity Cold start: up to two days
Investment costs	New nuclear power station: 3000 – 6000 €/kW	**Variable costs**	Fuel costs: 10 - 15 €/MWh, additional "hidden" costs for insurance (~ 2,5 €/MWh), for security measures: (~ 1,2 €/MWh), and for waste disposal
Installed capacity	In Europe ~ 130 GW total installed capacity	**Minimum load**	PWR: 50%, BWR: 60% Might be lowered to PWR: 20% BWR: 40%
Lifetime	50 – 60 years ,,400 cold starts, up to	**Maximum period of shifting**	N/A

	100 000 load changes	**/ Maximum energy content (h)**	
Maturity of technology	High		
Environmental effects	Nuclear power has high intrinsic environmental risks because of its radioactive fuel. After accidents in Chernobyl, Ukraine, and Fukushima, Japan, whole regions are contaminated. Radioactivity is a key problem also in waste disposal. Nuclear waste has to be sealed for thousands of years.		
Barriers	Economic barriers: Hidden costs for high risks and waste disposal Technical barriers: Flexible operation is not considered compatible with nuclear technology Political barriers: nuclear power is highly controversial in parts of Europe, especially in Germany.		
Potential role	In Europe, nuclear power stations cover nearly 30% of the total electricity demand each year. Although many of the existing plants are expected to retire in the next decade and new projects are few, nuclear power stations will continue to play an important role in the European electricity system.		

Biogas power plant flexibility

Supply

The electricity production via Biogas plants (biogas usage in a CHP which is in a Gas-Otto-engine) can ramp up and down reacting to changes in the residual demand. The biogas production itself runs continuously 8760 h/a. Flexibility on the biogas production itself is possible but limited (reaction time several hours to days; flexibility is about 50% of the capacity). More promising flexibility options are due to biogas storage and CHP operation according to electricity production needs. The following table is filled in for the second option.

The technical adoption will be to enlarge the biogas storage (which is usually constructed to store 3 – 6 hours biogas production) and the installation of additional CHP capacities (compared to basic load operation). An additional option is to upgrade of biogas to natural gas quality, and inject the resulting bio-methane into the existing natural gas grid.

Efficiency	Electrical efficiency: 33% to 40%	**Reaction time**	On-off within seconds.
Investment costs	Investment costs range from 3000 €/kW (big installations) to above 6000 €/kW for small installations	**Variable costs**	Production cost biogas: 12 – 25 ct/kWh_{el} Costs for flexibility (investment in storage and extension of CHP engine and generator): 1.5 – 2.5 ct/kWh_{el}, alternatively: cost for biogas upgrading to natural gas quality and bio-methane injection: 1.5 – 2.5 ct/kWh_{el}
Installed capacity	~ 22 GW in 2011	**Maximum energy content**	Typical storage capacities of produced biogas are 3-6 hours
Lifetime	Installations: 20 years, Generator and engine are usually retrofitted after 12 years	**Maximum period of shifting**	Storage can be enlarged to 12 hours. Additional capacity is possible but limited by volume and technology (low pressure storage). Biogas injection into the natural gas grid offers huge storage capacities.

Maturity of technology	The technology is well developed. About ten thousand biogas plants are in commercial operation in Europe. Biogas upgrading and grid injection is well developed with about 100 commercial plants in operation.
Environmental effects	Very limited: methane is a potent greenhouse gas, H_2S emissions can be toxic, accidents from digerster leaks are very rare. Ramps and part load operation might lead to higher emissions. An environmental advantage is avoided emission by manure treatment (manure emits methane during storage)
Barriers	Economic barriers: Biogas production is expensive compared to other electricity generation. Technical barriers: For flexible operation, additional storage capacity has to be installed Political barriers: Biogas needs governmental support systems because electricity production for some options is too expensive for competitive electricity wholesale markets. Also use of bio energy meets public opposition due to possible impacts to food prices.
Potential role	Biogas offers a renewable energy option with promising flexibility options.

Flexibility in combined heat and power

Combined Heat and Power plants produce electricity by waste heat that is generated from a central process. There are three main types of CHP, based on their central operation:

1. Industrial CHP, that produce heat for an industrial process and the power generation follows the variations of the industrial heat demand,
2. Residential CHP, used for district heating which follow daily/seasonal patterns according to the district heat demand,
3. Micro-CHP, which are small-scale installations that are used for residential heating purposes.

Supply

Due to their dependence on other primary tasks (heat production), CHP plants are often must-run plants, that generate power at every electricity price level. They present a significant part of inflexible capacity in the system. If a heat storage system is applied, CHP plants can respond to changes in the residual demand and their operation can be optimised to electricity prices. This flexibility reduces must-run capacity in the system.

Efficiency	Electric: 15% (micro CHP) – 46% (CCGT-CHP) Thermal: 81% (micro CHP) – 42% (CCGT-CHP) Total: 96% (micro CHP) – 88.4% (CCGT-CHP)	**Reaction time**	5 – 20%/min Warm start: Small installations: 5 min, CCGT: 3 hours Cold start: CCGT: 5 hours Hot start CCGT: 50 – 85 min
Investment costs	Approximate investment costs: micro CHP 16 000 €/kW Mini CHP: 3400 €/kW CCGT: 1000 €/kW, Heat storage: 9,5 – 24,3 €/kW_{el} per year	**Variable costs**	Micro CHP: 20 €/MWh Mini CHP: 28 €/MWh CCGT CHP: 3 €/MWh Excluding fuel costs
Installed capacity	EU-27: 134 GW CHP	**Maximum energy content (MWh)**	N/A

Lifetime	20 – 40 years	**Maxi-mum period of shifting**	4 – 12 hours
Maturity of technology	High		
Environmen-tal effects			
Barriers	Economic barriers: Reduced efficiency compared to electricity only plants, addition-al investment in heat storage, fluctuations in heat supply Technical barriers: higher abrasion due to ramps, electrical operation highly con-straint because of thermal duties		
Potential role	CHP is politically supported because of its high energy efficiency, including thermal energy supply		

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Active power control of renewable energy

Active power control of 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. 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. Both operations come at the expense of an overall reduction in VRES output.

VRES 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 VRES shares. However, there are several challenges to implementing greater VRES controls. First, due to their stochastic nature, provision of flexibility from VRES 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 VRES to maximise the produced energy and has no incentive to curtail production.

Supply

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.

Efficiency	N/A	**Reaction time**	100%/min
Investment costs	PV: 1000-1800 €/kW Wind onshore: 1000 - 1800 €/kW Wind offshore: 3400 - 4500	**Variable costs**	0

	€/kW		
Installed capacity	EU-27: ~ 94 GW in 2011 (Eurostat)	**Maximum energy content (MWh)**	N/A
Lifetime	Wind turbines: 20 – 25 years (EWEA), PV: 30 – 40 years (BSW Solar)	**Maximum period of shifting**	N/A
Maturity of technology	Middle		
Environmental effects			
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 role	Due to marginal cost of zero, active power control 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 VRES .		

Demand management in industrial installations

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.

Demand

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 realise, however its realisation will depend on sufficient incentives.

Efficiency	95 - 100%	**Reaction time**	20 – 100%/min (BET)
Investment costs	Can be very low	**Variable costs**	Can be very low
Installed capacity	On average, nearly 120 GW of industrial consumption in EU-27	**Maximum energy content**	N/A
Lifetime	N/A	**Maximum period of shifting**	1 – 24 hours (BET)
Maturity of technology	High, some industrial customers already provide interruptible loads on balancing markets		
Environmental effects	N/A		
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 role	Short-term and cost-efficient solution, additional potential for complete shut-down in minutes, but at much higher costs (value of lost load)		

Demand management in services and households

Demand

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 as small as 5 kW. 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.

Efficiency	95 – 100%	**Reaction time**	100%/min
Investment costs	300 – 370 € for meter, gateway and installation	**Variable costs**	0
Installed capacity	On average about 92 GW residential demand, and additionally about 92 GW from the service sector	**Maximum energy content**	N/A
Lifetime	N/A	**Maximum period of shifting (h)**	1 – 24 hours
Maturity of technology	Low		
Environmental effects	N/A		
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 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.		
Potential role	Demand management might turn out to be the game changer in electricity markets, when flexible demand sets the marginal price in wholesale markets.		

Electric vehicles

Electric vehicles make use of electricity stored in electric vehicle batteries, selectively charged by the grid when the vehicle is parked at a charging spot. The characteristics of transportation demand allow fleets of EVs to be used as a flexibility option for the power system in two key operational modes:

1. G2V (Grid-to-Vehicle, where fleets of EVs are operated as a DSM option, enabling a shifting of the charging times); or
2. V2G (Vehicle-to-Grid where in addition to charging, the batteries of EVs could be discharged and feed power to the grid).

Demand

Due to their primary use as means of transportation, the provision of flexibility from EVs is subject to many constraints and is inherently uncertain. However, studies show that EVs can be a competitive flexibility option because they are expected to be highly available during evening and night time hours (charging at home). During daytime their availability depends on the existence of charging infrastructure in other locations (e.g. work). Key advantage is that EVs form a parallel development and as such their investment costs are driven by the transport sector. However, we still lack business models that could allow their use.

Efficiency	93%	**Reaction time**	100 %/min
Investment costs	N/A	**Variable costs**	-
Installed capacity	6.5 kW/vehicle (Nissan Aaltra)	**Maximum energy content**	29 kWh/vehicle (Nissan Aaltra)
Lifetime	5-15 (battery)	**Maximum period of shifting**	Hours
Maturity of technology	The maturity of batteries used in EVs is high. However, there is low experience with using fleets of EVs for flexibility provision.		
Environmental effects	The risks are related to the risks from the specific batteries used in EVs		
Barriers	Economic barriers: no business model (yet) Technical barriers: very few electric vehicles. Existence of sufficient charging infrastructure. Communication and control infrastructure. Battery technology (low driving ranges, high battery costs) Political barriers: low public acceptance for system use of EVs		
Potential role	Potential role for provision of balancing and reserve power. Also for solution of more localised problems.		

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 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.

Demand

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.	**Reaction time**	100%/min
Investment costs	530 – 2560 €/kW for heat pumps	**Variable costs**	1000 Euro/Liter – 50 Wh
Installed capacity	N/A	**Maximum energy content**	Storage facilities are designed for about 2 hours
Lifetime	15 – 20 years	**Maximum period of shifting**	Depending on the isolation of the building – up to 24 hours
Maturity of technology	High		
Environmental effects			
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 role	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 VRES, and reduce carbon by displacing fossil-fuel heat sources.

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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.

Energy Storage

Efficiency	70 – 85 %	**Reaction time**	40 – 100 %/min
Investment costs	New installations: 1300 – 2000 €/kW extension of existing plants: 850 – 1300 €/kW Small Scale: 1875 - 3225 €/kW	**Variable costs**	103.5 – 322.5 €/kWh (Large - small scale)
Installed capacity	World: 127 GW EU-27: 42,6 GW	**Maximum energy content**	6 – 10 hours
Lifetime	>13000 - 15000 cycles >50 years	**Maximum period of shifting**	Hours to days
Maturity of technology	Pumped hydro storage is the most prevalent and mature energy storage technology.		
Environmental effects	Reservoirs destroy natural habitat and ecosystems		
Barriers	Economic barriers: Long return of investment (> 30 years) Technical barriers: low energy intensity, very specific siting requirements Political barriers: low public acceptance or support, high requirements in approval process		
Potential role	The storage technology is mostly used as an energy management technology, ideal for load levelling and peak shaving, time shifting, power quality measures, and emergency supply		

(AA-) CAES

In compressed air energy storage (CAES), energy is stored mechanically by running electric motors to compress air into enclosed volumes. For discharge, the electrical energy is fed into the inlet of a combustion turbine. The combustion turbine consumes some fossil fuel in its operation, but it can generate almost three times the energy of a similarly sized conventional gas turbine.
A second generation of Advanced Adiabatic CAES technology (AA-CAES) captures the heat energy during compression and returns it by heating the air as it passes to the combustion turbine inlet for carbon free operation. Another approach involves compressing and expanding the air slowly such that it nearly maintains the same temperature. Key barriers to the technology are its efficiency, high capital costs and the specific siting requirements needed.

Energy Storage

Efficiency	CAES: 40 - 50% AA-CAES: 60-75%	**Reaction time**	Cold start: 5-15 minutes Discharging mode: 10% / 3 seconds Charging mode: 20% / min
Investment costs	720 – 1000 €/kW	**Variable costs**	0
Installed capacity	Currently only 2 installations 321 MW in Germany110 MW in US	**Maximum energy content**	8 – 20 hours
Lifetime	>10000 - 13000 cycles 20 – 40 years)	**Maximum period of shifting**	Hours to days
Maturity of technology	Low - Only two CAES systems exist in commercial operation, second generation systems (advanced adiabatic) are under development. Smaller scale systems are also possible.		
Environmental effects	Cavern must be pressure tight to prevent leakage.		
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 role	Large-scale application for medium-term energy storage, time shifting		

Flywheels

Flywheels are rotating masses that store electricity in the form of kinetic energy. Energy is transferred in and out using a motor-generator that spins a shaft connected to the rotor. To minimise the energy lost during rotation, flywheels are often maintained in a vacuum and rest on very low friction bearings (e.g. magnetic). The rotor is the main component of the flywheel. Rotor characteristics such as inertia and maximum rotational rate determine the energy capacity and density of the devices. The motor-generator and associated power electronics determine the maximum power of the flywheel, allowing for power and energy capacities to be decoupled. Key advantages of the technology is the fast response times and the provision of inertia for grid stabilisation, while key barrier is the high investment costs.

Energy Storage

Efficiency	70-95%	**Reaction time**	Milliseconds
Investment costs	1500 – 1650 €/kW	**Variable costs**	0
Installed capacity	0.00 2- 340 MW	**Maximum energy content**	0.25 hours
Lifetime	15 – 20 years 20 000 – 70 000 000 cycles	**Maximum period of shifting**	0.25 hours
Maturity of technology	Low		
Environmental effects	N/A		
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 role	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		

Batteries

Batteries refer to Electrochemical energy storage technologies that convert 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 with cells which contain two electrodes (e.g. lead acid, lithium ion),
2. high temperature batteries that store electricity in molten salt (e.g. NAS), and
3. flow batteries that make use of electrolyte liquids in tanks (e.g. Zn/Br Redox, FE/Cr Redox).

Energy Storage

Efficiency	Li-ion: 85 – 98 % Redox flow: 60 – 75 % Lead Acid: 75 – 90% NaS: 70 – 85%	**Reaction time**	< seconds
Investment costs	Li-ion: 815 – 1165 €/kW Lead Acid: 1275 – 3675 €/kW Redox flow: 1080 – 2775 €/kW	**Variable costs**	Li-ion: 3255 – 4650 €/kWh Lead Acid: 320 – 735 €/kWh Redox flow: 220 – 625 €/kWh
Installed capacity	Globally about 400 MW	**Maximum energy content**	Lead acid: 4 – 5 hours Redox flow: 5 hours
Lifetime	Lead Acid: < 3 – 15 years, 250 - 1500 cycles Advanced lead acid: 2200 – 4500 cycles Li-ion: 5 – 15 years, 500 – 10000 cycles NaS: 10 – 15 years, 2500 – 4500 cycles Redox flow: 5 – 20 years, 1000 - >10000 cycles	**Maximum period of shifting**	Minutes to weeks
Maturity of technol-ogy	NaS, and Ni-Cd batteries are all mature technologies with example appli-cations for energy storage for grids. Li-ion is often used in portable appli-		

	cations, but on utility scale level, it is still in development
Environmental risks	Recycling of chemical components after decommissioning, thermally unstable metal oxide electrodes (Li-ion), acid could get out (Lead acid), explosion of hydrogen, poisonous lead
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 role	Mainly small scale application at moderate level of RES penetration. High potential for technical development and cost-reduction Could be used on distribution grid level, while pump storage and other “big scale” technologies work on the transportation 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

Power to Gas

Power to Gas refers to chemical energy storage, namely the use of electric energy to create fuels that may be burned in conventional power plants. Key fuel is synthetic methane (and hydrogen to some degree). The procedure consists of two steps:

1. Electricity is used in electrolysis to split water into hydrogen and oxygen.
2. Hydrogen is combined with carbon to create methane.

Methane is the main constituent of natural gas and therefore can be injected to the existing infrastructure for natural gas (grid and storage). The high storage capacity of the gas grid (e.g. apprx. 400 TWh for the German gas grid) could then be used for medium- and long-term storage purposes. A first demonstration project of kW-scale has been built and operated in Germany and a 6 MW German plant also began operation in 2013.
Key strength of chemical storage over some of the other technologies is its high energy density (kWh/liter) compared to most of the other technologies and its high shifting period. Key barrier is the low efficiency.

Efficiency	30-45%	**Reaction time**	Seconds to minutes
Investment costs	Currently at 3600 €/kW, 1000 €/kW envisaged in 2022	**Variable costs**	No additional cost for storage in gas grid
Installed capacity		**Maximum energy content**	N/A
Lifetime	10 – 30 years, 1000 – 10000 cycles	**Maximum period of shifting**	Weeks to months
Maturity of technology	A first demonstration project of kW-scale has been built and operated in Germany and MW-scale demonstrations have been proposed.		
Environmental risks	Direct incorporation of hydrogen into the gas grid can cause problems		
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 role	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.		

Market options to uncap flexibility

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.

System

In the synchronous power system of continental Europe, balancing market products are divided into three groups. Primary control power should be fully deployed within seconds, automatically reacting to grid frequency deviations. Secondary control power has to be available within five minutes while tertiary control responds within 15 minutes. 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.

Geographic market size

Small systems with limited ability to trade with neighbouring systems need local flexibility options. Increasing the system size by removing network constraints allows sharing and more efficient use of flexibility resources. Furthermore, with increasing geographical size of the market, VRES variability is reduced by spatial levelling and local imbalances have lower effects on the total system. This is especially true for regions with different power plant fleets and different climate characteristics.

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 VRES.

Scheduling times

Services on electricity markets are traded in defined time blocks. Shorter scheduling periods for

fulfilling the contract opens the market especially for VRES and for bids from the demand side. VRES 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. Allowing transactions within operating periods can further reduce the need for control power and increase schedule accuracy.
Gate closure
VRES 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 VRES. 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.
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.

Network options to increase flexibility

Power networks provide the spatial sharing of flexible resources. A key measure of the capacity of networks to share resources is the power transfer capability (PTC) between areas. In meshed systems, there are three key options for increasing this capability: a) dynamic assessment of power transfer capability, b) network expansion and c) power flow control.

Net-
work

Dynamic assessment of power transfer capability

The operational PTC is generally defined in advance based on specific procedures drafted by the respective TSOs. The estimation is based on forecasted infeed patterns and specific assumptions on the system line limits (e.g. net transfer capacity calculation from ENTSOE). This results to relatively conservative estimates of the PTCs due to the inclusion of security margins and the use of static line capacity limits. A dynamic assessment of PTC is a key solution for increasing the available power transfer capability in the following two main ways:

a) Reduction of security margins: The PTCs should allow some security margin to accommodate differences in power flow patterns due to forecast errors. The longer the scheduling periods considered, the higher this security margin gets. Using more up to date information by a dynamic assessment of PTC allows reducing the considered security margins, and freeing up more capacity for market operations.
b) Dynamic line rating: Static (nominal) line ratings are considered for the assessment of the PTC. However, such ratings are in general conservative, corresponding to 'worst-case' expected conditions along the route of the respective line. Unlike nominal line rating, dynamic line rating (DLR) takes advantage of the fact that the physical power transmission capacity of overhead lines is a function of ambient conditions (temperature, wind speed, wind angle and solar insolation). DLR is hence often less conservative than NLR, which assumes more challenging ambient conditions.

Network expansion options

This refers to the addition of new transmission lines in the system which add transfer capacity between areas where congestions are observed. Construction of transmission lines is often met with high public opposition due to health and land value reduction concerns. There are two key technological options (HVAC and HVDC) and two realisation options (overhead lines OHL and underground cables UGC), which lead to different impacts. OHL configurations present the highest corridor capacities however require more extensive corridors. Considering space requirements, HVAC technologies require larger corridors due to their higher electromagnetic emissions and larger towers than for HVDC transmission, triggering higher public opposition. Public opposition to UGC implementation is minimal since the transmission line is not visible. UGC configurations present lower capacities per circuit but the highest transmission intensity due to their reduced space requirements. HVDC UGC offer the highest capacities combined to easier installation and no requirements of extra equipment for reactive power compensation. However, UGC options lead to a significant increase (4-8 times more) to the costs.

Power flow control options

In meshed networks, it is often the case that congestions could be resolved by redirecting the power through alternative pathways. For this, power flow control devices should be installed in specific network points. The key devices used for such a role are FACTS and Phase-Shifting Transformers, while the controllability of HVDC technologies allows HVDC connections to be used for power flow control. Similar solutions (e.g. Voltage Controlled Distribution Transformers - VCDT) appear also in the medium and low voltage networks, enabling distributed voltage control in order to avoid network expansion when integrating higher shares of distributed resources. The public opposition to the use of such devices is lower, but related costs are high and the efficiency of the solution depends highly on the specific characteristics of the system where it is applied.

3 Mapping of flexibility options

Different flexibility options are best suited to different operational timeframes. Figure 9 shows a summary of the potential of the analysed options with respect to three key operational timeframes: short term flexibility (balancing markets with a timeframe of up to one hour), mid-term flexibility (spot markets - up to days), and long term flexibility (future contracts – seasonal variations). Colour shades show the suitability of the technology with respect to the different flexibility timeframes. To assess this suitability we investigate the position of the technology in future systems with very high VRES shares and whether operational constraints in a high-VRES system may hinder the provision of flexibility in the timeframe under investigation.

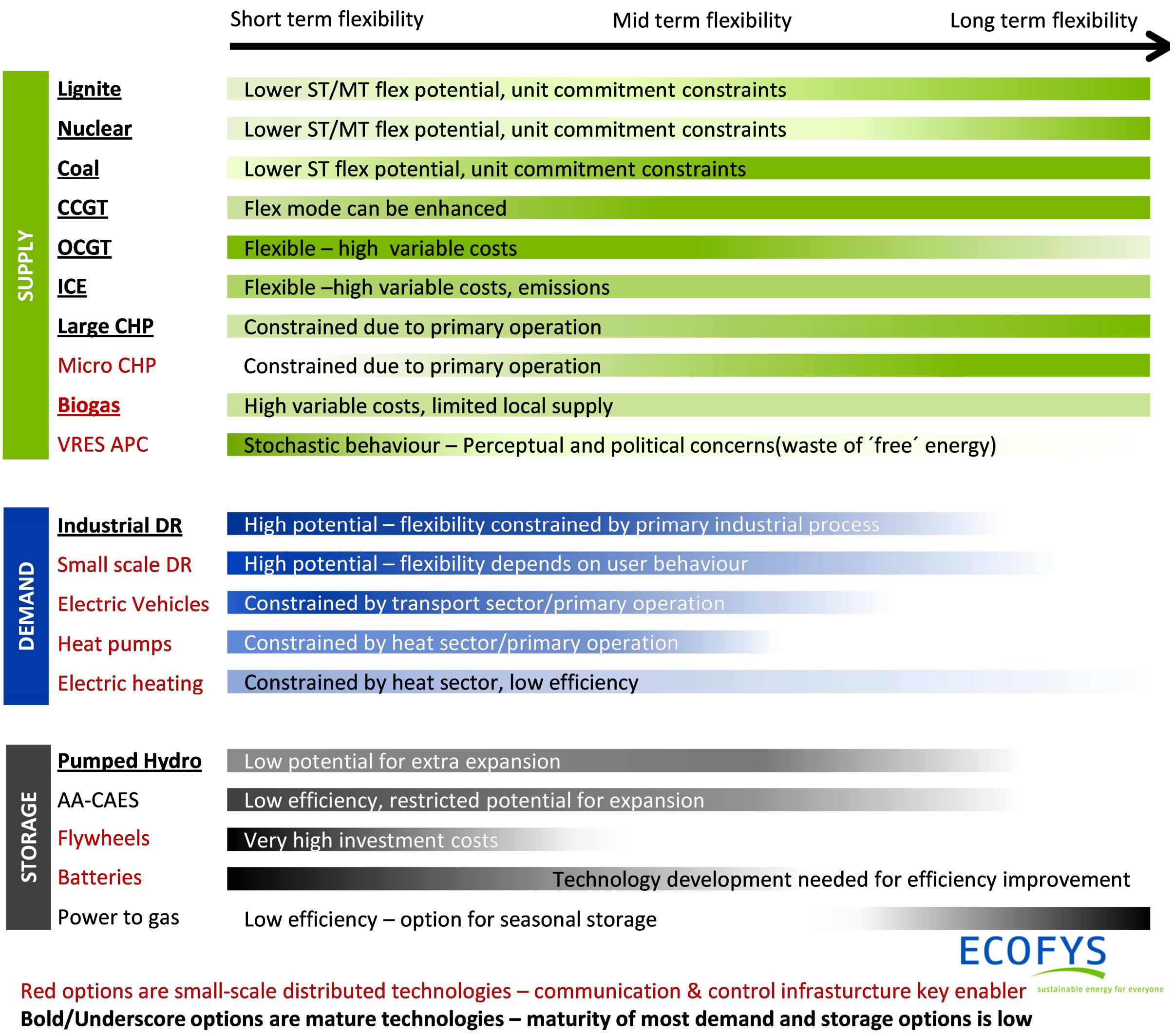

Figure 9: Comparative assessment of the characteristics of flexibility options in different operational timeframes

In Figure 9, bold/underscore titles indicate technologies that are considered large scale and mature while red colour indicates small-scale distributed technologies. As expected, the main mature options are on the supply side; on the demand side, key mature option is the large-scale industrial DR, while pumped hydro is the main mature storage technology. Most of the new demand and storage options are small scale technologies. The development of these options depends on the enabling of communication and control infrastructure, which for such small scale units will represent a relatively higher share of costs.

The variety of options show that there are several options to be considered in the different timeframes. Below we discuss the key conclusions for each timeframe under investigation.

3.1 Mid-Term Flexibility

Higher shares of zero-marginal cost VRES contribute downward pressure on market prices making it difficult for flexible units to cover their high variable and investment costs. The cycling of thermal power plants is increasing and their operational availability (unit commitment) depends on their cold start/shut down times and their ramping capabilities. Cold starts from lignite and nuclear power plants take more than days, while coal, CHP and CCGT power plants require more than one hour to reach their full output. As shown in Figure 9, in systems with high VRES shares, base load and mid-load operation of power plants is restricted. The operation of inflexible lignite and nuclear plants is reduced. Key supply options for mid-term flexibility are flexible coal, gas and ICE plants. The potential of CHP depends on thermal storage and on primary operation constraints. Active power control of VRES is an option for mid-term flexibility, but risks perceptual and political concerns over lost clean energy.

Bulk electric energy storage plants such as pumped hydro have traditionally operated when the price difference between low and high prices is high enough to recover energy losses. Operation according to day ahead markets requires a certain storage capacity, to provide supply for more than one hour. Pumped storage plants are a mature option in this respect, but their potential is restricted by geographic constraints, while AA-CAES present lower efficiencies. Large scale storage capacity for several hours is expensive for batteries and other small scale storage options.

Industrial demand management could offer a good demand shifting option. This option has low variable costs, but in order to make use of the potential, big industrial customers would have to change their power acquisition strategy or single installations have to be pooled by an aggregator. Small-scale DR presents a potential but this option requires enabling communication and control infrastructure and also rises data issues, that should be solved. Options driven by developments in other sectors (electric vehicles and heat pumps) have the advantage of not presenting an power sector related investment, but are restricted by their primary operation.

3.2 Short-Term Flexibility

Traditionally, the supply side (thermal power plants) provided the majority of short term flexibility. With increasing VRES shares, key options for provision of short term flexibility from cold start are OCGT and ICE, but at the expense of high variable costs. The short-term flexibility potential of micro-CHP is deemed rather low, due to the constraints of the primary operation. Active power control of VRES presents a high potential, however the inherent operational uncertainty due to the stochastic prime mover hinders the potential of the option.

Storage options present a potential for short-term flexibility. Pumped storage hydro plants is a mature and cost-effective option, however with a low potential for extra capacity due to the constraints on geographic siting. Imbalances of up to 15 minutes can be solved by flywheels and the technology is particularly suited for very short term flexibility requirements. Batteries (and EVs) offer the required technological characteristics, but further technology development is required and due to the distributed nature, suitable IT infrastructure is a key enabler.

Demand management could provide economical short term flexibility. Industrial DR is the low hanging fruit but should include management involvement for industrial customers while small-scale DR is restricted by primary operation and by the relative cost of control and communication infrastructure.

3.3 Long term flexibility

In the long run, only one storage technology competes with thermal power plants: Power to gas. Thermal power plants can be seen as facilities, that store electricity in form of fuels. Power to gas is the technology that transforms electricity back into a fuel (gas or hydrogen), however in the expense of high losses. This is only economical in systems with very high shares of VRES, and correspondingly high numbers of oversupply events. On the demand side, no significant options appear, since shifting demand in longer periods is not generally applicable.

3.4 Market barriers

Prices are determined by marginal costs in wholesale markets. Additional VRES cause new challenges because wind and PV have low, close to zero marginal costs. They displace power plants with high variable costs in the market. This brings down the average electricity prices and reduces incentives to invest in new capacity for all generators. Still, conventional peak power plants are needed to meet load in times of low VRES generation. Figure 10 illustrates the long term consequences of additional VRES in the market: the residual load curve shifts down, and the number of full load hours for power plants is reduced. In the long run, this reduces market price incentives to invest in capital intensive base load power plants, and the power plant fleet is expected to have an increasing share of relatively flexibly peak load technology.

Currently, the markets experience a transition period where this market mechanism is distorted. Existing base load power plants offer electricity based on their very low variable costs. In times of oversupply they even provide electricity at negative prices. Highly flexible peak load power plants with high variable costs are not able to compete in this market and are crowded out. When overcapacities are phased out because of lifetimes, prices are likely to increase and incentives for new capacity might evolve. An alternative solution is the consideration of capacity markets which could finance additional investments and prevent price peaks. However, depending on their regulation, they could add additional distortions to the market.

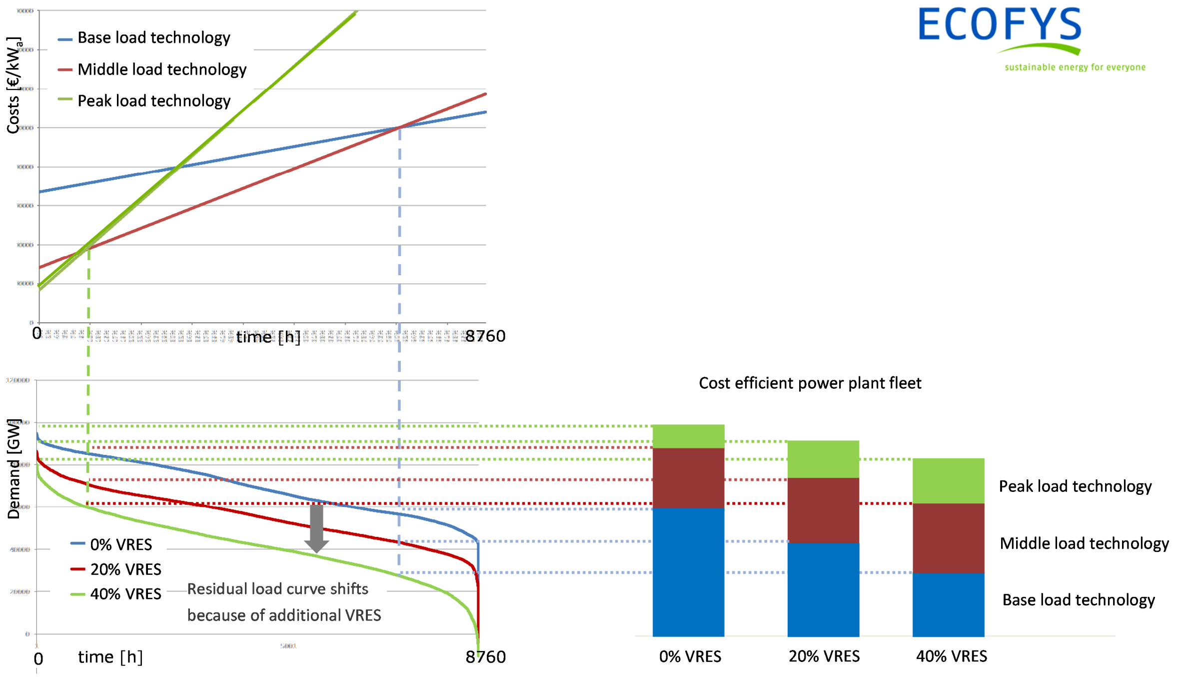

Figure 10: Impacts of VRES on cost efficient power plant fleet (illustration according to Nabe (2006))

A key difference in investment between supply and the other options is that investments in supply options are driven by high market prices, while market price variability (spreads) is an indicator for investments in storage and demand side options. However, market prices and spreads are related to each other, making any intervention on the supply side having impact to the role of the other options. In particular, price peaks do not only give incentives to invest in new power plant capacity. They also trigger additional storage capacity and demand management, since they normally lead to higher price spreads. In markets with overcapacities, market price variability is reduced, since there is enough generation capacity in each hour available. Therefore, the incentives for storage and demand options are removed. Making future markets provide sufficient incentives for peaking capacity and flexibility is a key challenge towards systems with higher VRES shares.

One main barrier to demand management is a lack of systems and incentives for loads to participate in power system operations. Smart metering is one system that could significantly boost the prospects for residential and commercial demand management. In the EU, smart meters are expected to be entirely rolled out by 2020. Additionally, attractive incentives need to be available. Pooling customers may be another way to make smaller loads more acceptable to grid operators and help bring demand management to the market.

4 Conclusions and Recommendations

This chapter summarises the main conclusions of the analysis.

A flexibility gap is created by the shift towards high-VRES systems

In future markets with increasing shares of VRES, additional flexibility is needed to maintain system reliability as the variations in supply and demand grow to levels far beyond what is seen in today's systems. VRES reduce the flexibility resources in the system by displacing traditional supply side flexibility providers while simultaneously increasing the need for flexibility due to their inherent stochastic nature. This creates a "flexibility gap" that will need to be covered by new flexibility options. Such options can be deployed both on the supply and demand sides. Storage technologies represent important flexibility options by shifting supply and demand in time. Figure 11 shows an illustration of the opening of the flexibility gap in future electricity markets and how different options will take shares of the new flexibility demand.

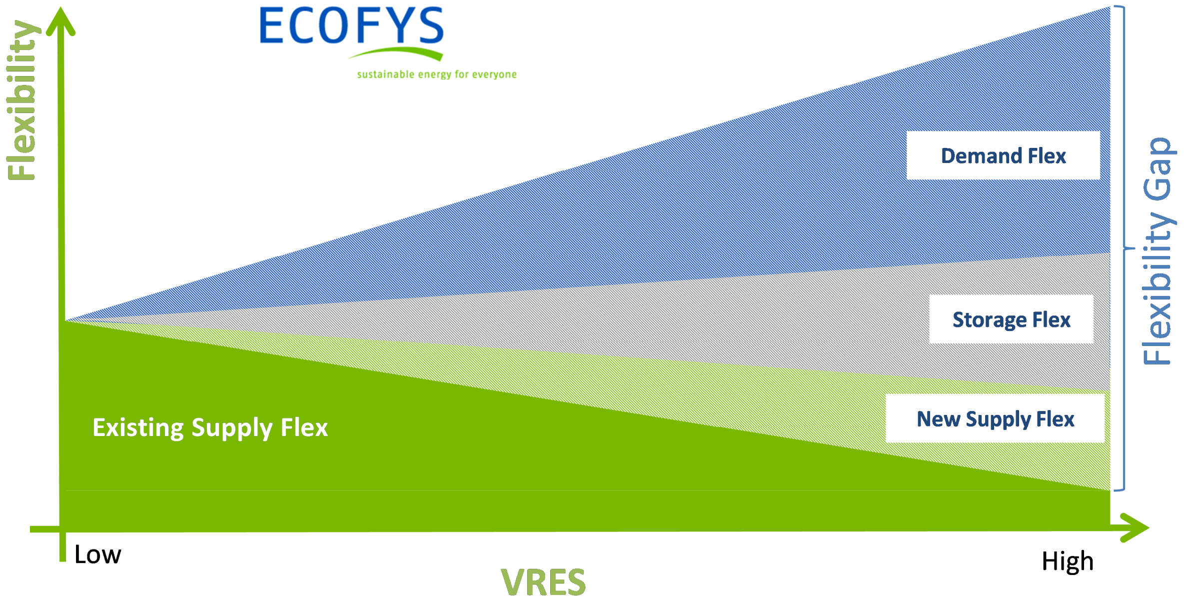

Figure 11: Flexibility gap in European electricity systems with different shares of VRES

New flexibility options in demand and storage require control and communication infrastructure

Many new flexibility options are small-scale distributed technologies. A key enabler for the realisation of these options is implementing cost-effective communication and control infrastructure.

VRES control is unavoidable for higher RES shares

For systems with higher VRES shares, more sophisticated control of VRES can be a more cost effective opportunity for providing system flexibility (or alternatively, reducing the needed flexibility). Active power control of VRES faces institutional, perceptual, and potentially political challenges due to the perception that renewable energy is being wasted. However, modest reductions in renewable resource output can translate to large capital investment savings in other competing options.

Changing the market for reducing the flexibility gap

Markets have prequalification standards. They are set to guarantee certain standards in trade. Often, these standards have been developed with regard to thermal generation plants. A review of prequalification standards could open additional markets to new flexibility options and to VRES. Examples are:

- Minimum bid sizes can be reduced to allow smaller generation capacities to the markets. For distributed generation, pooling is a viable option to enter a market – if it is allowed on the market.
- Short scheduling periods open the markets to new players, especially from the demand side and from VRES. PV, for example, can only bid into the market at certain hours a day. The maximum flexibility depends on the weather. Consumption patterns allow shifting of demand also only for certain timeframes.
- Gate closure times should be set as close to the fulfilment period as possible. Forecasts for VRES become better over time, therefore late gate closure limits the requirements for balancing VRES.

Incentives and systems for demand management are needed

Industrial customers respond to market price incentives. There are already demand management bidders on the market for tertiary balancing. Real time tariffs and scarcity pricing are means for encouraging efficient markets. Other customers may respond to other incentives, such as participation in green electricity programs, energy efficiency incentives, more efficient or comfortable energy systems, and technological improvements (e.g., better access to energy usage data).

Extending the market size is a no regret solution

One cross-market flexibility is the extension of market size. On the one hand, grid extensions allow further trade, on the other hand, market design options can enhance international trading and make use of differences in the European electricity systems.

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