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ENTEC

Energy Transition Expertise Centre

Digitalisation of Energy Flexibility

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Acronyms used in this report

Abbreviation	Description
ADMS	advanced distribution management system
AMI	advanced metering infrastructure
aFRR	automated frequency restoration reserves
BEMS	building energy management systems
BEV	battery electric vehicle
BRP	balancing responsible parties
BSP	balancing service provider
CAPEX	capital expenditures
CD	conventionally decarbonised
CHP	combined heat and power
cVPPs	community-based VPPs
CPO	charge-point operator
DER	distributed energy resources
DHC	district heating and cooling
DERMS	distributed energy resource management systems
DG ENER	Directorate-General Energy
DSO	distribution system operator
DSR	demand-side response
EaaS	energy-as-a-service
EED	energy efficiency directive
EMS	energy management systems
EnC	energy communities
ENTSO-E	European network of transmission system operators for electricity
EPBD	energy performance of buildings directive
ESCO	energy service company
EV	electric vehicle
FCR	frequency containment reserves
FED	final energy demand
FFR	firm frequency response
GBP	British pound sterling
GHG	greenhouse gas
HEMS	home energy management systems
HVAC	heating, ventilation and air conditioning
ICT	information and communications technology
IEMD	internal market for electricity directive
IoT	internet of things
LT/MT	low- and medium-temperature heat

Abbreviation	Description
MARI platform	Manually Activate Reserves Initiative
MAS	multi-agent systems
mFRR	manual frequency restoration reserves
MWYE	megawatt year
n.d.	no date
nRMSE	normalised root-mean-square error
NWA	non-wire alternatives
O&M	operations and maintenance
OEM	original equipment manufacturers
OMS	outage management systems
OPEX	operating expenses
PICASSO	Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation
P2G	peer-to-grid
P2P	peer-to-peer
PV	photovoltaic
RED II	renewable energy directive
RES	renewable energy source
RR	replacement reserve
SCADA	supervisory control and data acquisition
SOGL	System Operation Guideline
TCOO	total cost of ownership
TERRE	Trans European Replacement Reserves Exchange
TSO	transmission system operator
V2G	vehicle to grid
VPP	virtual power plant

Content

Executive summary

In 2019, the European Commission announced its European Green Deal, a set of policy initiatives to curb CO_2 emissions across the economy by 2050, and in summer 2021 the Commission presented the Fit for 55 package, which set an intermediate target to reduce emissions by 55% from 1990 levels by 2030[1]. Additionally, Fit for 55 would, among other initiatives, increase the target share of renewables in the overall energy mix from 32% to 40% by 2030. Currently, 20% of all energy in the European Union comes from renewable sources; achieving the Fit for 55 goal would mean a doubling of renewable energy sources in the next nine years[2]. For the energy sector, achieving this target will entail shifting from conventional to renewable energy sources at an increased pace.

Most renewable energy sources, such as wind and solar, are fluctuating and non-dispatchable; that is, they cannot be controlled by grid operators or market needs but instead are weather-dependent. This fluctuation in supply can create mismatches between generation and demand that requires additional flexibility to equilibrate the power system.

This report, researched and written by the Energy Transition Expertise Centre (EnTEC) under the auspices of the European Union looks at topics related to energy transition and focuses on potential solutions for enabling a renewables-based power system that are primarily at least strongly digital. It mainly examines digitally enabled flexibility solutions that leverage existing infrastructure, and does not include purpose-built non-digital flexibility solutions such as utility-scale batteries and gas power plants.

EnTEC will support the transformation of the EU energy system by monitoring and analysing trends in technologies and innovations and their impacts on the ongoing energy transition. It will provide the European Commission with recommendations for policy responses and triggering the debate regarding societal changes required to achieve the European Green Deal targets.

As a first step, EnTEC and the European Commission's Directorate-General for Energy (DG ENER) selected a set of use and business cases, for deeper analysis of their flexibility potential, near-term (2030) maturity and facilitator requirements – that is, changes needed on societal, governmental, infrastructure and regulation levels. An overview of selected business cases is shown in Table 1.

Table 1. Overview of selected business cases

Use case	Business case	Description
Distribution system operator (DSO) grid automation and optimisation	Distributed energy resource management systems (DERMS)	Includes distributed energy resources in grid management
Virtual power plants (VPPs)	VPPs for intraday spot market	Provides profit optimisation in energy-only markets

[1] European Commission, Delivering the European Green Deal, July 2021, https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal/delivering-european-green-deal_en. European Commission/Council of the European Union, "The EU's Plan for a Green Transition," Fit for 55, n.d., https://www.consilium.europa.eu/en/policies/green-deal/eu-plan-for-a-green-transition/.

[2] European Commission, "Renewable energy statistics," Eurostat/Statistics Explained, data extracted December 2020, n.d., https://ec.europa.eu/eurostat/statistics-explained/index.php?title=Renewable_energy_statistics.

Use case	Business case	Description
	VPPs for balancing reserves	Provides frequency containment reserve and automated and manually activated reserve by VPP
	VPPs for internal balancing	Balances responsibility, reduces forecast errors, and schedules compliance
Energy communities	Energy sharing and peer-to-peer trading	Optimises self-consumption[3] of neighbourhoods, energy communities and regional VPPs
	District heating and cooling	Provides power flexibility by buffering heat and electrified generation; combined heat and power (CHP) plants provide intraday power flexibility
On-site building optimisation	Building energy management systems (BEMS)	Uses smart heat pumps to maximise flexibility with minimal impact on user comfort
Industrial load control	Industrial hybrid heating	Expands low- and medium-temperature heat processes with electrified heating, creating hybrid heating systems that allow for optimal demand-side-response (DSR) capacity
Home automation/residential demand-side response (DSR)	Residential heat pumps	Uses smart heat pumps to maximise flexibility with minimal impact to user comfort
	Home energy management systems (HEMS)	Automates demand response through distributed storage and smart inverters; includes heating, ventilation and air conditioning (HVAC) and battery storage but excludes heat pumps
Electric vehicle (EV) smart charging	Price-responsive charging	Adapts EV load-shifting charging pattern based on real-time or time-of-use price signal
	Self-consumption optimisation	Targets the maximisation of self-supply in households that also generate renewable electricity
Vehicle to grid	Price-responsive bidirectional charging	Manages bidirectional interaction of EVs with the grid based on real-time or time-of-use price signal
	Congestion management and ancillary services using V2G	Manages load shifting, specifically for grid-balancing measures, as driven by the grid operator

[3] Self-consumption is the share of the total energy production consumed by the owner of the energy system. (Rasmus Luthander et al., "Photovoltaic self-consumption in buildings: A review," *Applied Energy* 142 (2015).)

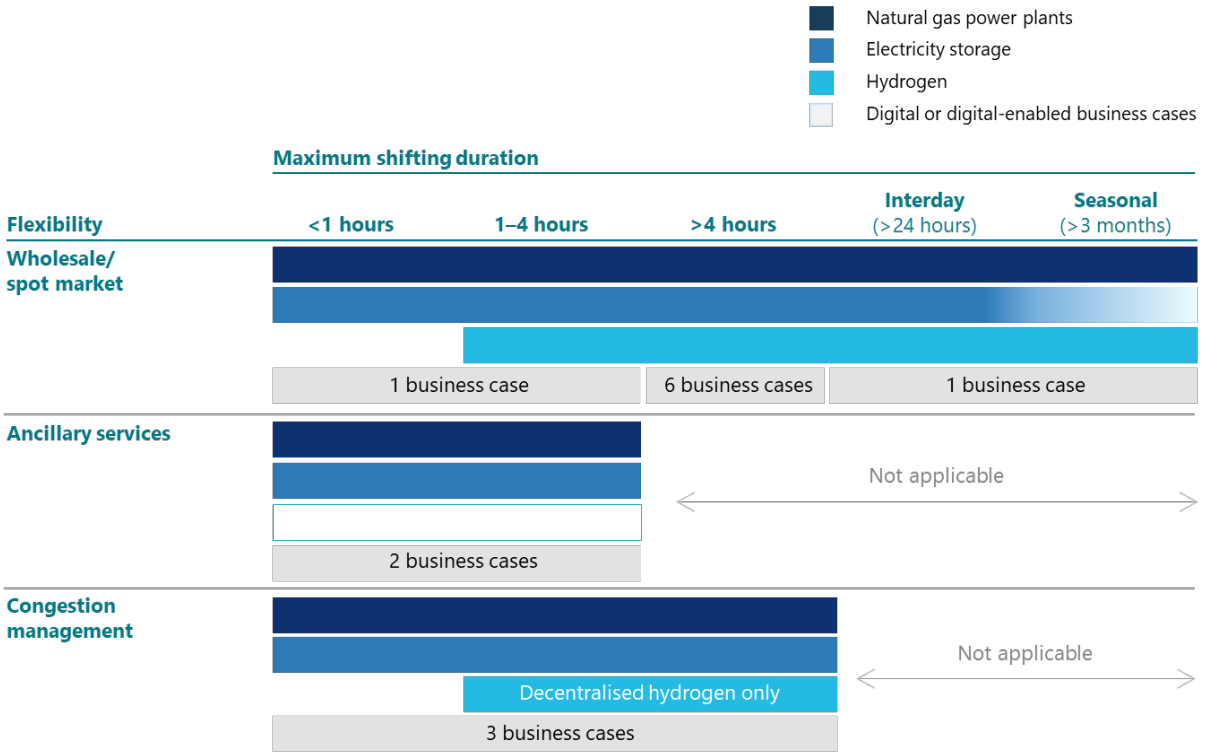
These business cases were then analysed in detail regarding their flexibility impact, market overview, stakeholder mapping, innovation assessment, economic viability, technical assessment and risk. A summary of results for each business case can be found in the appendix.

Analysing these cases in their entirety showed that digital flexibility solutions, most of them linked to demand side response (DSR), could provide for a significant part of the system's flexibility needs in terms of flexibility types and maximum shifting durations. All these applications would complement other, non-digital flexibility solutions and could enable a more economical renewables-based power system.

The analysed business cases, or flexibility solutions, were also mapped against the required 2050 flexibility capacity for each of the three flexibility types (wholesale/spot market, ancillary services and congestion management), as shown in Figure 1. This analysis shows that ancillary services and congestion-management applications, where the demand is estimated to be relatively low, can likely be covered fully by digital solutions. The much higher demand for flexibility in the wholesale/spot market (estimated at 630 gigawatts by 2050) can likely also be roughly matched by the analysed business cases, but is unlikely to be exceeded. Profitability of some of the business cases remains challenging and may require support.

The overview is based on high-level modelling of the maximum flexibility potential of these use and business cases in 2050. Actual numbers will depend on many factors – such as regulation, technical development and public support – most of which are uncertain, making any estimate a rough indication. This report takes into account competition for resources among various business cases, notably for electric vehicles and residential batteries, which is elaborated in Chapter 13.

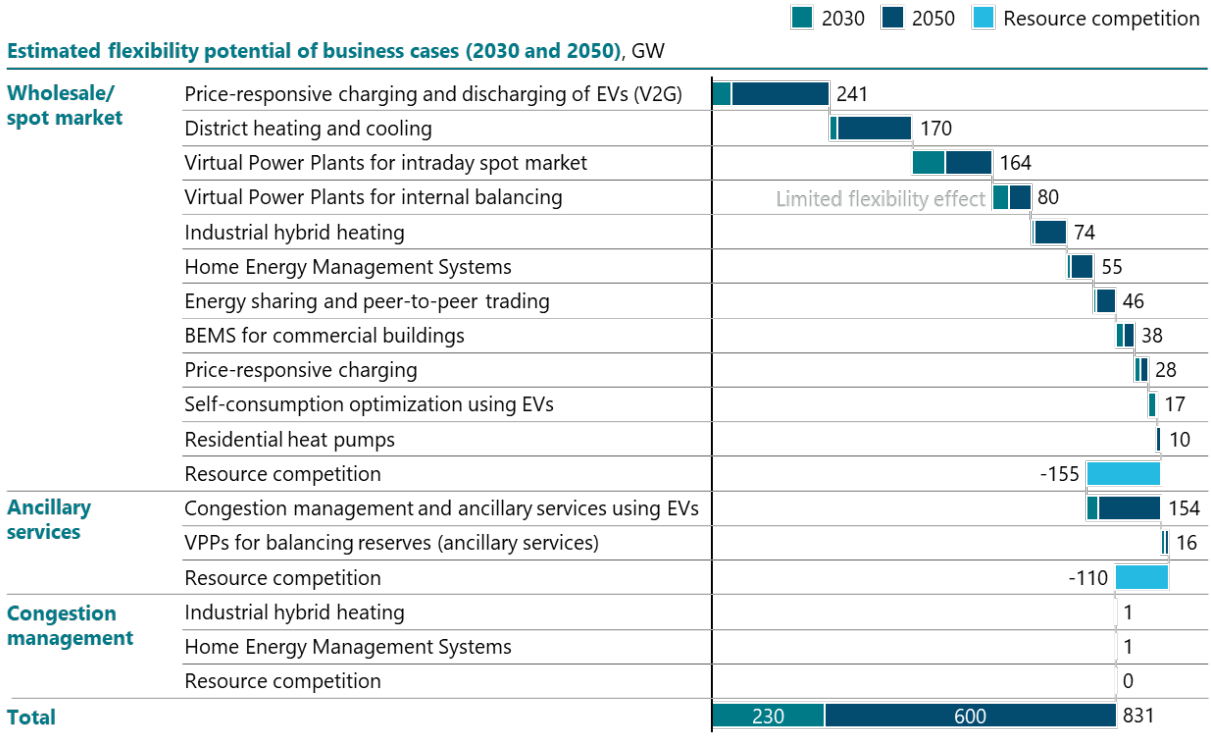
Figure 1. Maximum shifting duration for natural gas power plants, electricity storage, hydrogen and digital or digital-enabled business cases[4]



To further illustrate the implications of digital energy flexibility cases, a scenario was constructed using an illustrative merit order curve, as shown in Figure 2. This hypothetical scenario would offer 583 gigawatts of energy flexibility from digital business cases by 2050, at an estimated EUR 40 billion of capital investments (all numbers are considered estimates). Both wholesale intraday and ancillary services would require an additional 45 gigawatts of non-digital power flexibility to meet the flexibility demand of 630 and 60 gigawatts, respectively, due to the profitability limits of the considered digital flexibility solutions. Meeting the 2050 goals would require a significant participation of industrial low- and medium-temperature heating systems, with 100% hybridisation; dispatchable renewable energy sources, with about 60% aggregated into virtual power plants; about half of district heating networks offering flexibility; and a little more than a third of battery electric vehicles participating in smart charging or vehicle-to-grid activities.

[4] Proton exchange membrane (PEM) fuel cells, which generate electrical power from hydrogen, have shown short ramp rates in experiments and in future may be used in ancillary-services applications.

Figure 2. Capacity of digital solutions by flexibility type



This report identifies key digital-infrastructure enablers, suggests existing gaps and bottlenecks, and examines recent European best-practice data-exchange guidelines, including Gaia-X, IDS and others[5]. It assesses the impact of these enabling frameworks and of current regulations on the selected use and business cases to identify potential issues and any need for additional preparation or research needed for implementation. The report also assesses key technologies and digital infrastructure elements that will be required, including standardisation, and comments on the impact of market design and customer participation.

Finally, the report identifies businesses that are already delivering some of these use cases across the European Union and beyond, as well as use cases where digital infrastructure and analytics are being used to disrupt other industries, highlighting some of the policy lessons learned. It should thus be a catalyst for the development of economical digital flexibility solutions to enable a net-zero Europe.

[5] For more information, see chapters 13 and 14.

1 Introduction

In 2019, the European Commission (EC) announced its European Green Deal, a set of policy initiatives that aims to fully curb CO_2 emissions across the economy by 2050; as an intermediate target, it has set the goal of reducing emissions by 55% from 1990 levels by 2030[6]. This target, the cornerstone of the European Green Deal, is laid out in the EC's Fit for 55 legislation package[7], which would, among other things, increase the share of renewables in the overall energy mix from 32% to 40% by 2030. Currently, 20% of all energy in the European Union comes from renewable sources[8].

For the energy sector, Fit for 55 entails radically shifting from conventional to renewable energy sources at an increased pace. Most renewable energy sources, such as wind and solar, are fluctuating and non-dispatchable; that is, they cannot be controlled by grid operators or market needs but instead are weather-dependent. This fluctuation in supply can create a significant mismatch between generation and demand that can vary from seconds to seasons, with distribution depending on meteorological conditions and the setup of the energy system, among other factors. Balancing the system depends on adding flexibility through an array of solutions that can quickly and accurately address the fluctuations inherent in the energy sources. The graph below shows a summer day with a significant intraday mismatch (shaded area) due to high solar power generation, shown by the green line, versus a much flatter daily power demand or bulk load profile, illustrated by the blue line.

Figure 3. Schematic representation of significant intraday mismatch from nondispatchable solar power generation and power demand bulk load.

Three main types of flexibility can be added to the energy pipeline:

- *Flexible generation* encompasses every kind of dispatchable generation, including biomass, geothermal, and the two types that dispatch the fastest, reservoir hydroelectric power plants and gas turbines that burn natural gas, hydrogen or biogas.
- *Demand management* encompasses all options to alter consumer demand to better fit the generation profile through incentive programmes, education to elicit changes in behaviour and energy-use plans that encourage off-peak use when possible.
- *Storage* encompasses every possibility for storing energy and releasing it later in the form of electricity. It includes batteries, pumped hydroelectric storage, thermal systems, and emerging hydrogen, compressed air and superconducting magnet systems.

All three types of flexibility can be achieved with a variety of approaches, including both digital and analog.

This report, conducted as part of a broader effort by the Energy Transition Expertise Centre (EnTEC) under the auspices of the European Union to study topics related to energy transition, focuses on

[6] European Commission, *Delivering the European Green Deal*, July 2021, https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal/delivering-european-green-deal_en.

[7] European Commission/Council of the European Union, "The EU's Plan for a Green Transition," Fit for 55, n.d., https://www.consilium.europa.eu/en/policies/eu-plan-for-a-green-transition/; and European Commission, "European Green Deal: Commission proposes transformation of EU economy and society to meet climate ambitions," July 2021, https://ec.europa.eu/commission/presscorner/detail/en/ip_21_3541.

[8] European Commission, "Renewable energy statistics," Eurostat/Statistics Explained, data extracted December 2020, https://ec.europa.eu/eurostat/statistics-explained/index.php?title=Renewable_energy_statistics.

solutions that are primarily digital or at least strongly digitally enabled. It mainly examines distributed flexibility solutions that build on existing infrastructure, and does not cover purpose-built non-digital flexibility solutions such as utility-scale batteries and gas power plants.

The advantages of digital solutions include lower capital expenditures and faster deployment due to the reuse of existing infrastructure. In addition, the distributed nature of digital solutions allows for resolving congestion at the local level. However, digital solutions pose some challenges, including cybersecurity risks (likely requiring robust regulation) and their relatively ephemeral nature: They can't provide long-term (seasonal) storage. Therefore, the expectation is that both digital and non-digital solutions – competing and complementary – will be needed to increase flexibility for the renewable energy system of the future.

The aim of this report is to identify and analyse promising digital-flexibility business cases.

Chapter 2 provides a list of business cases identified for detailed analysis in this report and outlines the selection process.

Chapters 3 through 12 provide detailed descriptions and analyses of the chosen business cases, looking at the flexibility impact, market overview, stakeholder mapping, innovation assessment, economic viability, technical assessment and risk analysis of each.

Chapter 13 compares the business cases with one another and looks at factors such as competition among business cases. It also provides an illustrative scenario that shows how the projected margin (as a proxy for profitability) can drive business case impact at scale. In this scenario, digital power flexibility is complemented by non-digital power flexibility options based on current margin projections.

Chapters 1415 and 16 focus on the enablers that would help bring the analysed business cases to scale by identifying a target and the gaps and barriers to be overcome to achieve this goal. The former focuses on the digital infrastructure required, while the latter looks at the regulatory framework without making specific policy recommendations.

Finally, Chapter 17 presents some examples of successful implementation of the described digital business cases both within and outside the European Union, and looks at comparable digital transformations in other sectors.

2 Identification and selection of use cases and business cases

This Chapter provides a framework for the selection of business cases based on a high-level assessment of flexibility potential, near-term maturity and other factors.

An initial list of power-flexibility use cases was obtained from expert interviews and the literature. Using a selection framework, this list was reduced to a final selection of 14 power-flexibility business cases. This Chapter details the selection framework and provides an intermediate output list of use and business cases as well as the final list of 14 business cases.

This report defines *use case* and *business case* as follows:

A *use case* covers a specific sector of the energy value chain. It is an overarching term for a bundle of business cases. Examples of use cases include virtual power plants, electric-vehicle smart charging and on-site building optimisation.

A *business case* is narrowed down for a specific market or application within the use-case category and examines technical, marketing and other aspects of the specific digital solution. For the use case on home automation, for example, business cases include residential heat pumps, smart appliances and home energy management systems. A group of business cases providing flexibility to a power system will also be referred to as *digital flexibility solutions*.

Two reference years are used throughout this study to assess use cases and business cases. The first is 2030, a milestone for assessing the maturity of business cases in contributing to energy-system flexibility; the second is 2050, which is the target year for climate neutrality as set out in the European Green Deal[9]. These years are widely used in the literature and support the direct comparison of business cases. The maturity assessment is important in the selection of business cases, as they vary widely in their maturity and, therefore, in their likely ability to scale up quickly.

Every digital flexibility solution can provide flexibility to the European power system. Most accomplish this by active participating in European flexibility markets that trade power and capacity. The two main types of markets that trade power in Europe are wholesale markets and ancillary services:

- *Wholesale markets* allow participants to trade power to match supply and demand. Wholesale markets include day-ahead and intraday spot markets.
- *Ancillary services* allow grid operators to procure emergency services that can be activated to stabilise the grid. They include balancing frequency containment reserves (FCRs), automated and manual frequency restoration reserves (aFRR and mFRR, respectively) and replacement reserves (long-term contracts).

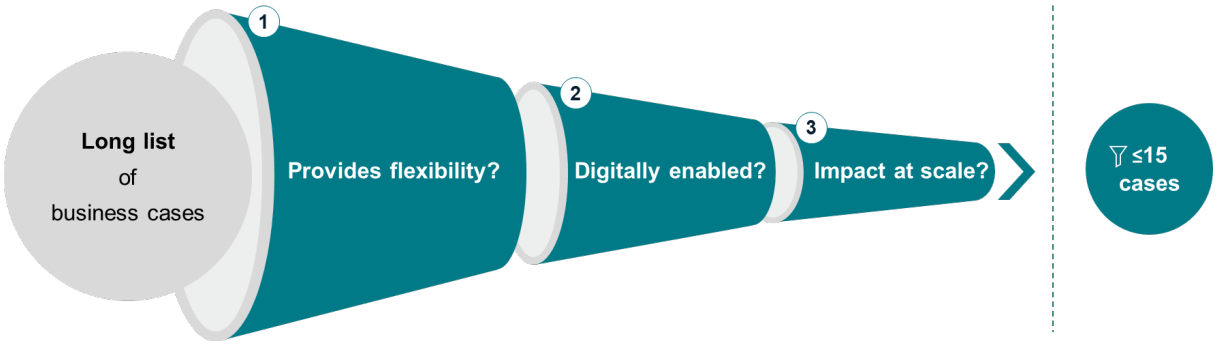
In addition to market trading, transmission system operators (TSOs) can take remedial actions to manage congestion or resolve a mismatch between the market outcome – that is, the power traded on the wholesale markets – and the physical limitations of the grid.

2.1 Framework for initial business-case selection

A framework of three guiding criteria was defined for selecting 14 business cases from our initial list of more than 30 non-centralised power-flexibility use cases, as shown in Figure 4.

[9] European Commission, *Delivering the European Green Deal*.

Figure 4. Criteria for narrowing down the list of business cases



The three criteria used in the selection of business cases were that they must:

- Provide power flexibility.
- Be digitally enabled or have digital technology at their core.
- Be able to achieve impact at scale.

Table 2 shows the list of flexibility-providing use and business cases that also meet the second criterion shown in Figure 4 – being digitally enabled – but before the impact assessment.

Table 2. List of use cases and the business cases within each

Use case	Business case	Description	Flexibility capacity by 2050 (gigawatts)	Flexible energy by 2050 (terawatt hours)	Calculation	Near-term maturity	Type of flexibility
1: Transmission system operator (TSO) grid automation and optimisation	1.1: Location-based remuneration for grid services	Adjusts pricing based on time and location to proactively lower the risk of power-system imbalances	Enabler for other business cases, such as virtual power plants (VPPs)				Enabler
	1.2: Flexibility aggregation and data-driven asset management	Data shares to distribution system operators (DSOs) on real-time state of grid; performs data-driven grid maintenance to ensure sustained flexibility	Enabler for increasing effectiveness of other business cases				Enabler
	1.3: Remote control of renewables	Minimises curtailment of renewable energy sources through real-time optimisation of renewables at medium voltage	Closely related to VPPs and not considered as separate case			Mature market	
	1.4: Sensor-based grid optimisation	Uses data (including installing additional sensors) to improve grid operations and maintenance (O&M) and capacity	0.3 GW	4.7 TWh	• Expected congestion in 2050: 1.25 GW and 18.6 TWh • Estimated improvement potential from business case: 25%	Mature market	Congestion
2: DSO grid automation and optimisation	2.1: Distributed energy resource management systems (DERMS)	Includes distributed energy resources in grid management	Enabler for distributed generation and loads to participate in VPPs and thereby in the flexibility market				Enabler

Use case	Business case	Description	Flexibility capacity by 2050 (gigawatts)	Flexible energy by 2050 (terawatt hours)	Calculation	Near-term maturity	Type of flexibility
	2.2: O&M prioritisation from high-frequency demand-and-supply data	Maximises reliability of grid flexibility components through digitally enabled prioritisation of maintenance and upgrades	3 GW	23 TWh	• Discrepancy of EU electricity (consumption minus generation) excluding grid losses: 80 TWh (2018) • Estimated improvement potential from business case: ~30%, distributed evenly throughout the year (8,760 hours)	Commercial application	Ancillary services
	2.3: Third-party data services	Third-party microservices for residential generation and consumption assets, such as photovoltaic (PV), batteries and appliances	Estimate is highly uncertain due to low maturity, but low impact on flexibility expected				
3: Virtual power plants	3.1: VPPs for intraday spot market	Aggregates distributed energy resources for monetisation in wholesale markets	164 GW	426 TWh	Calculations detailed in Chapter 4	Mature market	Wholesale market
	3.2: VPPs for ancillary services (balancing reserves)	Provides frequency containment reserve, automated activated reserve and manually activated reserve by VPP	16 GW	7 TWh	Calculations detailed in Chapter 4	Mature market	Ancillary services
	3.3: VPPs for congestion management	Participates in congestion management in regulatory redispatch and flexibility markets	1 GW	15 TWh	VPPs' congestion management in TWh is based on historical data: • Congestion duration in Germany 2020: 11,560 GWh in 14,973h equals ~1 GW • Congestion-management costs in Europe 2020: EUR 1,548 million	Commercial application	Congestion management

Use case	Business case	Description	Flexibility capacity by 2050 (gigawatts)	Flexible energy by 2050 (terawatt hours)	Calculation	Near-term maturity	Type of flexibility
					• Congestion-management costs Germany 2020: 83 EUR/MWh times VPP share of system's total generation		
	3.4: VPPs for critical grid situations	Includes capability to black start, brown start and form grids	39 GW	0.1 TWh	• Black-start capacity in Germany 2020: 10 GW, extrapolated to Europe based on Germany's share of electricity consumption • Duration of power system restoration per year: 1h times VPPs' power-system restoration (GW)	Research/pilot	Ancillary services
	3.5: VPPS for internal balancing	Balances responsibility, reduces forecast errors, schedules compliance	80 GW	171 TWh	Calculations detailed in Chapter 4	Mature market	Wholesale market
	3.6: VPPs to exploit limited grid capacities	Balances responsibility through regional hybrid power plants close to a congested power line	64 GW	137 TWh	• Wind energy and PV: 2,636 GW, assuming 75% participate in VPPs • Forecast error per VPP: 4% normalised root-mean-square error (nRMSE) of full capacity yields 80 GW • Wind energy and PV: 5,204 TWh • Renewable energy curtailment: 3.2% to total capacity of VPPs' wind and PV generation	Commercial application	Congestion management
4: Energy communities	4.1: Energy sharing and	Optimises self-consumption, or the share of the total energy production consumed by the	46 GW	70 TWh	Calculations detailed in Chapter 5	Commercial application	Wholesale market

Use case	Business case	Description	Flexibility capacity by 2050 (gigawatts)	Flexible energy by 2050 (terawatt hours)	Calculation	Near-term maturity	Type of flexibility
	peer-to-peer trading	owner of the energy system[10], of neighbourhoods, energy communities and regional VPPs					
	4.2: Community demand response	Aggregates demand-side flexibility for monetisation on the wholesale market	13 GW	24 TWh	Leveraging input data from business case 8.1, price-responsive charging: • 24 TWh divided by 570 TWh times 309 GW equals 13 GW • Number of prosumer (citizens who produce all or part of their own energy demand) households in collectives 2050: 99 million • Energy consumption per capita in Europe: 0.6 GWh • Power generation of collectives 2050: 570 TWh	Mature market	Wholesale market and ancillary services
	4.3: Local microgrid/off-grid communities	Offers additional power-flexibility services independent of main power grids	15 GW	23 TWh	Share of microgrids in energy communities: 33%, applied to the 46 GW of business case 4.1, Energy-sharing and peer-to-peer trading	Commercial application	Wholesale market and ancillary services
	4.4: District heating and cooling (DHC)	Provides power flexibility by buffering heat and electrified generation; provides intraday	170 GW	451 TWh	Calculations detailed in Chapter 6	Commercial application	Wholesale market

[10] Rasmus Luthander et al., "Photovoltaic self-consumption in buildings: A review," *Applied Energy* 142 (2015).

Use case	Business case	Description	Flexibility capacity by 2050 (gigawatts)	Flexible energy by 2050 (terawatt hours)	Calculation	Near-term maturity	Type of flexibility
		power flexibility through combined heat and power plants					
5: On-site building optimisation	5.1: Building energy management systems (BEMS)	Uses smart heat pumps to maximise flexibility with minimal impact on user comfort	38 GW	50 TWh	Calculations detailed in Chapter 7	Mature market	Wholesale market
	5.2: Commercial heating, ventilation and air conditioning (HVAC)	Uses smart HVAC (excluding heat pumps) to maximise flexibility with minimal impact on user comfort	17 GW	37 TWh	Total load projected to be 150 TWh in 2050, with flexibility potential, estimated at 25%, distributed evenly throughout the year (8,760 hours)	Commercial application	Ancillary services
6: Industrial load control	6.1: Industrial demand-side response (DSR)	Provides demand-side response of industrial participation in flexibility market through electrification of heating and ability to buffer heat	74 GW	7.4 TWh	• European Union total industry peak load capacity is 557 GW; of which 46.5 GW can be used for demand response • Growth of 58% by 2050 yields 74 GW • Application of a two-hour demand shift 20 to 50 times a year equals up to 100 hours duration (7.4 TWh)	Commercial application	Wholesale market
	6.2: Industrial hybrid heating	Expands low-temperature and medium temperature (LT/MT) processes with electrified heating, creating hybrid heating systems that allow for optimal DSR capacity	75 GW	667 TWh	Calculations detailed in Chapter 8	Commercial application	Wholesale market

Use case	Business case	Description	Flexibility capacity by 2050 (gigawatts)	Flexible energy by 2050 (terawatt hours)	Calculation	Near-term maturity	Type of flexibility
7: Home automation/residential DSR	7.1: Residential heat pumps	Uses smart heat pumps to maximise flexibility with minimal impact on user comfort	10 GW	32 TWh	Calculations detailed in Chapter 9	Commercial application	Wholesale market, congestion and ancillary services
	7.2: Smart home/smart appliances	Optimises time-of-use electricity consumption to support system flexibility while minimising building consumption	11 GW	10 TWh	Total load projected to be 100 TWh (2050), with flexibility potential, estimated at 10%, distributed evenly throughout the year (8,760 hours)	Research/pilot	Congestion and ancillary services
	7.3: Home energy-management systems (HEMS)	Automates demand response through distributed storage and smart inverters. Includes HVAC and battery storage but excludes heat pumps, which are covered in business case 7.1.	57 GW	86 TWh	Calculations detailed in Chapter 10	Commercial application	Wholesale market, congestion and ancillary services
8: Electric vehicle (EV)smart charging	8.1: Price-responsive charging	Adapts EVs' load-shifting charging pattern based on real-time or time-of-use price signal	551 GW	101 TWh	Calculations detailed in Chapter 11	Commercial application	Wholesale market
	8.2: Congestion management and ancillary services	Manages load shifting, specifically for grid-balancing measures, as driven by the grid operator	4.8 to 7.7 GW	43 to 67 TWh	• Load reduction: average minimum weekly charging load • Load upshift: minimum availability for EV charging by location times charging capacity excluding average charging load • Adjustable energy: load reduction times 8,760 hours 100% participation	Commercial application	Congestion and ancillary services

Use case	Business case	Description	Flexibility capacity by 2050 (gigawatts)	Flexible energy by 2050 (terawatt hours)	Calculation	Near-term maturity	Type of flexibility
	8.3: Self-consumption optimisation	EV charging targets the maximisation of self-supply in households that also generate renewable electricity	17 GW	53 TWh	Calculations detailed in Chapter 11	Mature market	Wholesale market
9: Vehicle to grid	9.1: Price-responsive charging and discharging	Manages bidirectional interaction of EVs with the grid based on real-time or time-of-use price signal	236 GW	324 TWh	Calculations detailed in Chapter 12	Research/pilot	Wholesale market
	9.2: Congestion management and ancillary services	Manages load shifting, specifically for grid-balancing measures, as driven by the grid operator	153 GW	324 TWh	Calculations detailed in Chapter 12	Research/pilot	Congestion and ancillary services
	9.3: Self-consumption optimisation (V2G)	Optimisation of self-supply in households that also generate renewable electricity by utilising battery electric vehicle (BEV) battery as home battery (with limitations)	319 GW	574 TWh	Number of one-to-two-family dwellings in EU27: 99.8 million; by 2050, 50% will have EV and rooftop PV and will perform self-consumption	Research/pilot	Wholesale market
10: Cost-reflective pricing	10.1: Variable and visible prices for entire value chain	Reflects cost of providing electricity to customer, with variability based on time and location of consumption	Enabler for other business cases				

2.2 Impact assessment

The impact assessment covers the amount of flexibility the business case will provide to the energy system, its maturity by 2030 and the need for facilitators to achieve its application at scale.

2.2.1 Amount of flexibility provided to the energy system

To determine impact at scale, each business case is assessed against two criteria:

- *Maximum adjustable power*, or the maximum power that can be adjusted at a certain point in time, is the product of an estimate of the number of units installed by 2050 (the target year) and their average maximum power.
- *Total adjustable energy*, or the total energy that can be adjusted throughout the year, is the product of the maximum adjustable power and the duration of application that a business case can provide (equivalent to full-load hours).

As the adjustable power duration varies across business cases, some cases will be strong contributors to flexibility based on maximum adjustable power; others on total adjustable energy. Both measures are captured in the selection process, as they offer the energy system different flexibility values.

2.2.2 Near-term maturity (by 2030)

A detailed assessment logic was formulated to evaluate the future contributions of business cases currently in their infancy, and three levels of business-case maturity by 2030 were defined:

Research/pilots, or small projects not currently expected to make a profit. Still in the research/pilot phase by 2030 but predicted to reach maturity in about 10 years from then, if they go forward.

Commercial applications expected to make a profit. In commercial application by 2030 and predicted to reach maturity after three to 10 years.

Mature markets. Business cases that today have several suppliers and customers and are deployed in several countries.

2.2.3 Facilitators

Business cases may require significant changes – societal, governmental, infrastructural, regulatory and so forth – before power flexibility at scale can be provided. This is captured in the need for facilitators, for which again three levels were formulated:

- *Low requirement*. Very few structural changes are needed to today's power-system setup.
- *Medium requirement*. Changes are needed to enable the business case, but are manageable in scale and no major resistance is expected.
- *High requirement*. The changes needed are large and costly or are expected to meet with significant resistance due, for instance, to data privacy issues or disadvantages for certain stakeholders.

To facilitate the selection of business cases along these key dimensions, they were arranged in the matrix shown in Figure 5.

The final selection of business cases involved setting an indicative threshold, which serves as a first proposal for which cases to include for further analysis versus which ones to exclude from analysis. In our graphs, this threshold is set up as depending on the near-term maturity of the cases, meaning

that less mature cases need to have a higher expected impact than more mature cases in order to be prioritised.

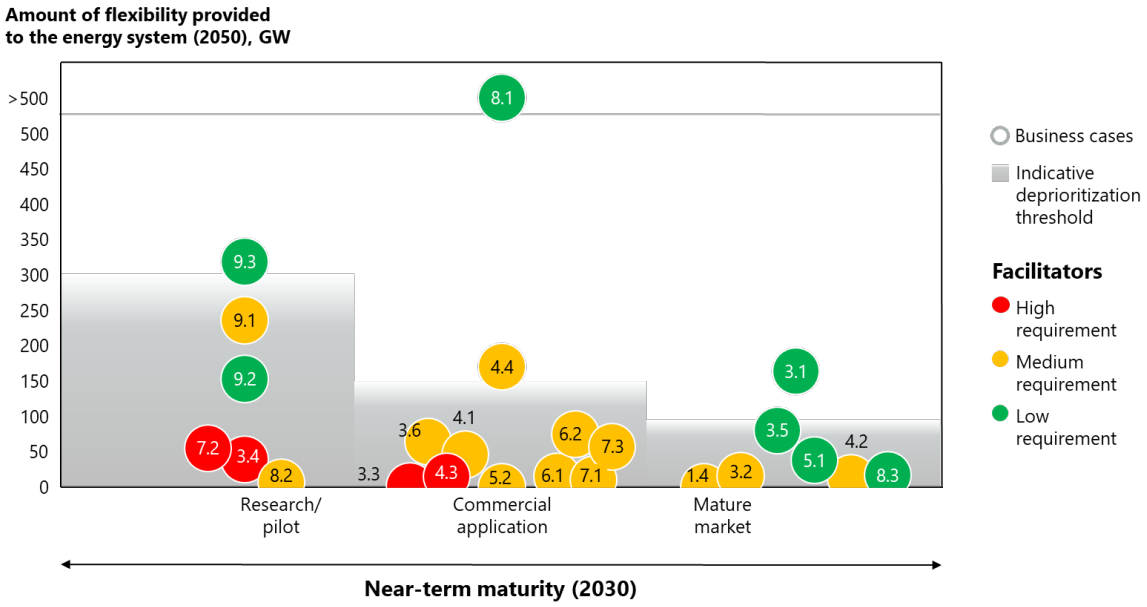
2.3 Business case selection

The results of business case selection through impact assessment are shown in Figure 5 and Figure 6. There is a wide range of flexibility capacity and maturity, with most business cases estimated to be in commercial application or mature market by 2030. The following sections provide more detail on the selection of business cases based on adjustable power and adjustable energy.

2.3.1 Maximum adjustable power

Figure 5 shows which business cases should provide the largest maximum adjustable power by 2050, with their projected maturity by 2030. Most cases will likely provide less than 100 gigawatts by 2050, and only a few have high requirements for application at scale.

Figure 5. Results of impact assessment: Projected maximum adjustable power of business cases (represented by their numbers, as designated in Table 2) by 2050



2.3.2 Total adjustable energy

Figure 6 shows which business cases are expected to provide the largest total adjustable energy by 2050, as well as their projected maturity by 2030. Most business cases are projected to provide less than 200 terawatt hours of energy flexibility by 2050.

Figure 6 Results of impact assessment: Projected total adjustable energy of business cases (represented by their numbers, as designated in Table 2) by 2050

The prioritisation threshold was set at roughly 100 gigawatts (capacity) or 100 terawatt hours (energy) for business cases expected to be in a mature market by 2030, at about 150 gigawatts or 150 terawatt hours for cases estimated to be in a commercial-application maturity stage in 2030,

and at about 300 gigawatts or 300 terawatt hours for business cases in the research/pilot phase by 2030.

Digital flexibility solutions may compete for the same business model or resources. If so, they are unlikely to coexist at their respective projected maximum power or energy, so adjustments must be made to their projected. For example, if 80% of the European Union's available electric vehicle fleet is used for wholesale intraday flexibility, only 20% of the available fleet is available for ancillary services, since the fleet cannot be fully used for both applications simultaneously. Capacity adjustments based on competition are considered in the overarching analysis in Chapter 13.

Additional factors considered in selecting the business cases analysed were:

- the need for facilitation to achieve deployment at scale (shown in Figure 5 and Figure 6)
- coverage of every sector of the energy value chain
- the breadth of the technology and underlying infrastructure

The use and business cases selected are listed in Table 3. The resulting system composition touches many sectors, from transport to industry to commercial and residential buildings.

Table 3. Overview of selected business cases and the rationale for their selection

Chapter	Use case	Business case	Rationale for selection
3	2: Distribution system operator (DSO) grid automation and optimisation	2.1: Distributed energy resource management systems (DERMS)	Key enabler for other business cases
4	3: Virtual power plant (VPPs) platforms	3.1: VPPs for intraday spot market	High impact (GW and TWh)
4		3.2: VPPs for ancillary services (balancing reserves)	High impact for ancillary services (TWh)
4		3.5: VPPs for internal balancing	High impact (GW and TWh)
5	4: Energy communities	4.1: Energy sharing and peer-to-peer trading	High impact (GW)
6		4.4: District heating and cooling	High impact (GW and TWh)
7	5: On-site building optimisation	5.1: Building energy management systems (BEMS)	Significant impact (TWh) and selected to ensure coverage of commercial buildings
8	6: Industrial load control	6.2: Industrial hybrid heating	High impact (TWh)
9	7: Home automation/residential demand-side response (DSR)	7.1: Residential heat pumps	Moderate impact (TWh); selected to ensure coverage of DSR using heat pumps in residential buildings (in addition to commercial buildings, as discussed in business case 5.1, BEMS)

Chapter	Use case	Business case	Rationale for selection
10		7.3: Home energy management systems (HEMS)	Significant impact (TWh); selected to include home batteries
11	8: Electric vehicle (EV) smart charging	8.1: Price-responsive charging	High impact (GW and TWh)
11		8.3: Self-consumption optimisation using EVs	Significant impact (TWh) and expectation of high profits as well as regulatory interest
12	9: Vehicle to grid	9.1: Price-responsive bidirectional charging	High impact (GW and TWh)
12		9.2: Congestion management and ancillary services using EVs	High impact (GW and TWh)

None of the business cases in TSO grid automation and optimisation (use case 1) or cost-reflective pricing (use case 10) were selected because they are generic enablers.

Some business cases are quite similar, so further context for their selection is discussed in the following sections.

2.3.2.1 Virtual power plants (use case 3)

Virtual power plants (VPPs) aggregate distributed energy resources (DER) and allow for market participation, which would not be feasible for individual energy resources. In terms of flexibility, VPP DERs fall into two categories: variable DERs, such as weather-dependent wind turbines and solar photovoltaic (PV) systems, and dispatchable DERs, such as combined heat and power (CHP) plants and batteries, whose generation can be ramped up and down more or less freely[11]. The generation of variable DERs can also be ramped down and, if they're not pre-curtailed (that is, if they are running at maximum capacity), ramped up; however, because ramping is accompanied by a loss of renewable energy, it is not considered flexibility for our purposes. Other flexibilities excluded from the VPP business cases include large-scale power plants, because they can act in flexibility markets without being integrated into VPPs, and energy storage systems, because they are the focus of other business cases. Therefore, the business cases analysed in detail in Chapter 4 examine the flexibilities of biomass, waste incineration and small combined heat and power plants that use natural gas, biogas, hydrogen or a mix. Dispatchable VPP capacity is applied with the highest priority for internal balancing (because of a regulatory obligation), followed by ancillary services and wholesale flexibility. Congestion management by VPPs, as captured in business cases 3.3 and 3.6, was not selected for detailed analysis.

2.3.2.2 Energy communities (use case 4)

Energy communities generate and share energy outside the traditional power generation, transmission and distribution system. In terms of grid use, energy communities can be within a geographical location (such as a housing complex), across contiguous property boundaries or distributed across non-contiguous boundaries.

[11] Regarding power consumption, VPPs in the US are more commonly associated with electricity production, demand-side response and other load-shifting approaches, whereas in Europe they are predominantly used for generation.

Three of the business cases for energy communities examine their role in the market, while the fourth analyses district heating and cooling (business case 4.4, detailed in Chapter 6)[12].

Energy sharing and peer-to-peer trading (business case 4.1, analysed in Chapter 5) address flexibility trading within energy communities, either between individual households or between households and the community. Community demand response (business case 4.2) covers the provision of flexibility by energy communities in external flexibility markets, such as the wholesale intraday spot market and ancillary services markets, while business case 4.3, local microgrid/off-grid communities, covers the operation of a power grid by energy communities, which results in additional requirements for the use of flexibility, such as for congestion management, frequency and voltage control or power system restoration. Business cases 4.2 and 4.3 were not selected for analysis because of their relatively low flexibility capacity potential.

2.3.2.3 Electric vehicle smart charging (use case 8) and vehicle-to-grid (use case 9)

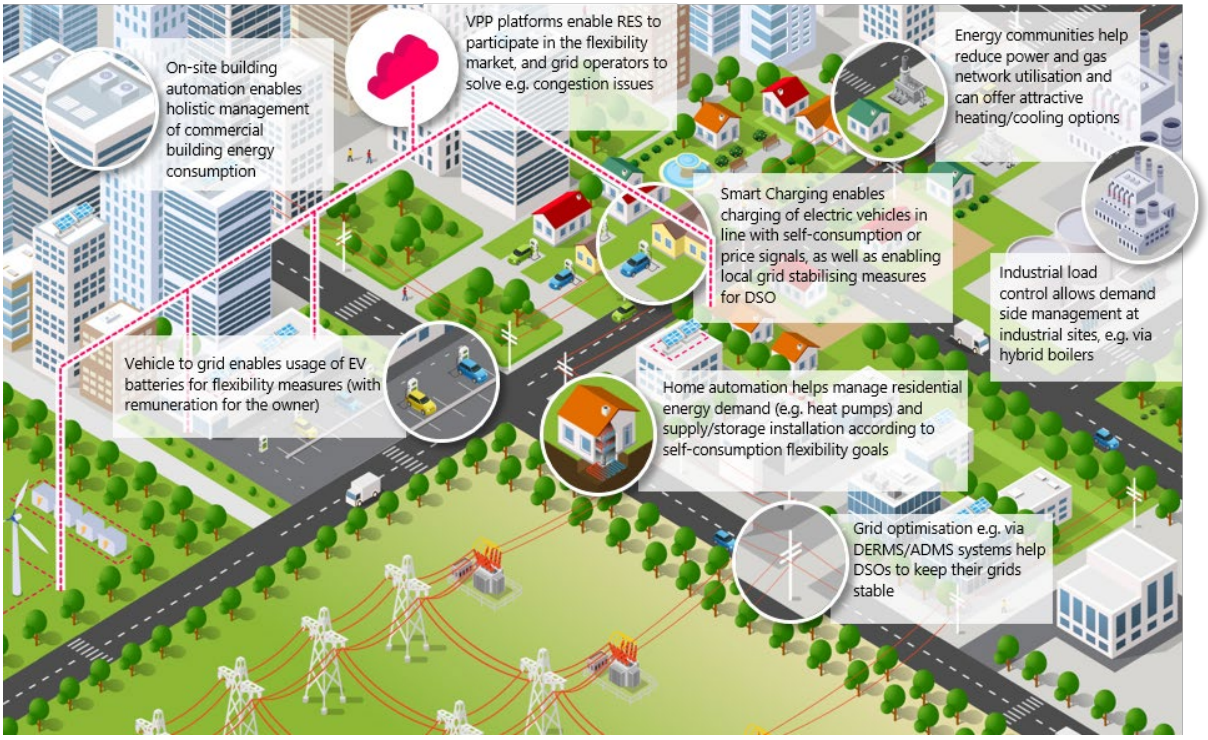
Use cases 8 and 9 discuss the flexible use of electric vehicles. In the case of smart charging – also referred to as demand response, unidirectional charging, or V1G – the charging pattern of an EV is adjusted (that is, the EV's demand is shifted) based on a price signal from the overarching energy system or from the local grid. Vehicle-to-grid (V2G) charging comprises all bidirectional charging activities, in which power from an EV can also be fed back to the grid. With V2G, EVs become "self-contained resources that can manage power flow and displace the need for electric utility infrastructure[13]." This study closely examines four potential business cases identified from the smart charging and V2G use cases. Price-responsive charging (business case 8.1) sees EVs adapt their load-shifting charging pattern based on real-time or time-of-use price signals. Self-consumption optimisation (business case 8.3) targets the maximisation of households' power self-supply with renewable sources such as solar panels and EVs, which may be equipped with further flexibility sources. Like business case 9.1, price-responsive charging lets EVs interact bidirectionally with the grid by adjusting their charging and discharging pattern and responding to real-time or time-of-use price signals, creating a significant monetisation opportunity. Finally, the congestion management and ancillary services with V2G case (business case 9.2) applies the V2G concept to EVs so they can participate in the congestion and ancillary markets.

Figure 7 gives a graphical overview of some selected cases to show the overall context.

[12] Frédéric Tounquet et al., *Energy Communities in the European Union*, revised final report, Asset/European Commission, May 2020, https://asset-ec.eu/wp-content/uploads/2019/07/ASSET-Energy-Communities-Revised-final-report.pdf.

[13] Benjamin Sovacool, *Electric Mobility and Vehicle-to-Grid Integration: Unexplored Questions and Benefits*, Sussex Energy Group at SPRU, January 12, 2018, https://blogs.sussex.ac.uk/sussexenergygroup/2018/01/12/electric-mobility-vehicle-grid-integration-unexplored-questions-benefits/

Figure 7. Graphical overview of selected use and business cases



3 Business case: Distributed energy resource management systems

This Chapter looks at a single business case in the distribution system operator (DSO) grid automation and optimisation use case: distributed energy resource management systems (DERMS), which seamlessly integrate a high share of distributed, volatile energy resources into the grid. This business case differs from the others because DERMS don't add power-flexibility capacity, but rather simply enable its addition into the power system.

To achieve the decarbonisation targets set out in the European Union's Green Deal and Fit for 55, integration at scale of distributed energy resources (DER, meaning small-scale solar, wind, batteries, EVs, etc.) is required. With high levels of distributed energy, DERMS can help reduce curtailment (the deliberate reduction of output to balance supply and demand) and can intelligently manage the grid-edge resources from a system-stability perspective.

This business case looks at the requirements and challenges for DERMS as enablers to integrating flexibility capacity. DERMS do not provide power flexibility alone; they are typically integrated into overarching advanced distribution management systems (ADMS), which are used by DSOs to optimise their operations from beginning to end. Because ADMS are also needed for integrating geographic information systems (GIS), the distribution supervisory control and data acquisition system (SCADA), outage management, and two- way communications, they are not included in this business case except in the economic assessment, where it is assumed that ADMS costs would be shared among the various applications, including DERMS.

Some key points relating to DERMS, ADMS and the closely related concept of virtual power plants (VPPs) are outlined in Table 4.

Table 4. Definitions of DERMS, ADMS and VPPs

	Operated by DSOs		**Operated by commercial traders**
	Advanced distribution management systems (ADMS)	**Distributed energy resource management systems (DERMS)**	**Virtual power plants (VPPs)**
Purpose	End-to-end optimisation of distribution system operator (DSO) operations	Efficient management of the growing number of grid-edge resources	Aggregation of distributed energy resources (DER) for monetisation on the capacity and ancillary-services markets
Application	ADMS integrate systems-level applications, like DERMS, outage management, distribution management and supervisory control and data acquisition (SCADA) systems; grid optimisation takes place every 5 to 15 minutes	DERMS aim to manage the voltage and power flows within the grid using local grid-load management (every 10 to 15 seconds)	VPPs aggregate DER and centrally optimise and control for power and flexibility services trading (e.g. curtailment, ancillary services)
Example players and ecosystems	Spain's Iberdrola Distribución Eléctrica combines grid infrastructure instrumentation with General Electric's ADMS to perform real-time grid	Western Power Distribution (WPD) in the United Kingdom deploys the Strata DERMS system developed by Scotland's Smarter Grid	Germany's Next Kraftwerke is a VPP and registered power trader (generation and demand capacity) providing balancing services to seven

	Operated by DSOs		Operated by commercial traders
	Advanced distribution management systems (ADMS)	**Distributed energy resource management systems (DERMS)**	**Virtual power plants (VPPs)**
	optimisation; this system includes a mobile version called UPGRID ADMS so that field crew have the same insight into grid status as the control room has	Solutions (SGS) for wide-area coordination and real-time control; WPD manages hosting capacity and implements flexibility services	EU transmission system operator (TSO) areas; Next Kraftwerke also provides flexible energy tariffs to industrial customers such as water utilities and smart-charging pilot projects
Limitations in high-RES context	Optimises overall system to grid limitations, but there remains a limit to the number of non-wires alternatives that can be provided when reaching grid capacity	Enables renewable energy sources (RES) integration and optimisation within spatial limitations but does not provide overall system optimisation	Trades power without considering spatial effect; as a result, does not consider local issues like congestion

3.1 Potential time frame for DERMS impact

The impact of DERMS is analysed differently from business cases that add power flexibility capacity, as DERMS only enable the addition of power flexibility, not power itself. This section describes the projected uptake of DERMS across the 27 member nations of the European Union.

Ultimately, the need for DERMS is defined by the grid state and the DSO's ability to stably integrate DER and specifically intermittent renewables such as solar and wind power. According Patric Lee, president of the San Diego–based energy infrastructure company PXiSE Energy Solutions, "Efforts to boost the amount of renewables in remote areas generally only yields about 30 percent of the energy the region needs"[14]. To go above that level, he says, DSOs will require DERMS to effectively integrate and manage DER flexibility.

To provide an estimate of potential growth in the use of DERMS in the European Union and the size of the DERMS market there, we evaluated the following:

- which countries cross the 30% threshold for intermittent renewable energy sources (RES) generation in a five-year window
- trends in the total intermittent RES generation over 30%
- triangulation of RES generation growth based on the results of the European Commission's EUCO3232.5[15], one of a group of scenarios, according to the Commission, that were "the basis for a number of impact assessments and the negotiations of the legislative acts proposed under the EU 2030 energy and climate policies". EUCO3232.5 was produced in 2019 and "models the

[14] Lisa Cohn, "PXiSE aims to create 'Federation of Microgrids' in Australia with DERMS," Microgrid Knowledge, December 2018, https://microgridknowledge.com/federation-of-microgrids-pxise-australia/.

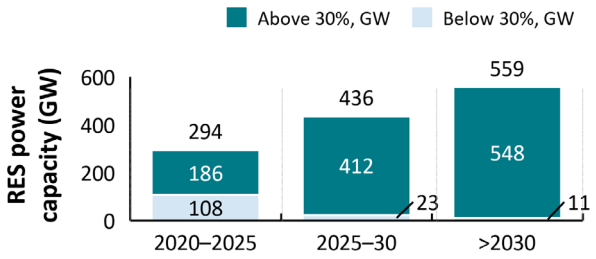
[15] EUCO3232.5 is one of a group of scenarios that were "the basis for a number of impact assessments and the negotiations of the legislative acts proposed under the EU 2030 energy and climate policies" (see European Commission, "Technical Note – Results of the EUCO3232.5 scenario on member states," n.d., https://ec.europa.eu/energy/sites/ener/files/technical_note_on_the_euco3232_final_14062019.pdf). EUCO3232.5 was produced in 2019 and "models the impact of achieving an energy efficiency target of 32.5% and a renewable energy target of 32%" by 2030 (see European Commission, "Older Modelling Results," n.d., https://ec.europa.eu/energy/data-analysis/energy-modelling/older-modelling-results_en).

impact of achieving an energy efficiency target of 32.5% and a renewable energy target of 32%" by 2030[16].

As shown in Figure 8 and Figure 9, Iberia, Benelux and the Nordic countries cross the 30% threshold before 2025, and by 2030, solar and wind power will make up 30% or more of power generation for most European countries.

Figure 8. Projected electricity generation from intermittent renewables by country or market[17]

Figure 9. Power generation from intermittent renewables for the European Union[18]



By 2030 most renewable energy capacity will be provided by countries that get more than 30% of their power generation from intermittent renewables. The adoption of DERMS should closely follow the adoption of intermittent renewable energy sources; since DERMS are important for optimal integration and management of DER, its uptake should encounter few challenges.

3.2 Market overview for DERMS

The European ADMS and DERMS market is consolidated following recent partnerships and acquisitions by traditional power-sector technology providers. The ADMS market is characterised by a small pool of vendors from Europe and the United States. These players are largely traditional power-sector technology providers like Hitachi ABB, General Electric, Siemens, Schneider Electric and Oracle (see Table 5). The DERMS market, by contrast, is characterised by a small but growing pool of vendors, all significantly younger than the ADMS vendors.

The product offerings in both categories have become increasingly modular, such that a DERMS could be offered by itself or as part of an overarching ADMS environment. Most applications require that DERMS and ADMS be operational together, though they can be purchased separately.

Recent partnerships – including Hitachi ABB (ADMS) with Enbala (DERMS) and Schneider Electric (ADMS) with AutoGrid (DERMS) – leverage the modularity of products.

Analysis suggests moderate challenges in the European ADMS market. Globally, approximately a dozen established technology providers offer ADMS, which limits the procurement options for DSOs. The DERMS market is dominated by a growing pool of young, innovative companies. The

[16] European Commission, "Older Modelling Results".

[17] European Commission, "Technical Note – Results of the EUCO3232.5 scenario on member states, which uses the PRIMES (Price-Induced Market Equilibrium System) model; for more on the model see https://e3modelling.com/wp-content/uploads/2018/10/The-PRIMES-MODEL-2018.pdf."

[18] European Commission, Directorate-General for Energy, Alex Jakeman, Christian Achtelik, and Vikrant Makwana, Digital Technologies and Use Cases in the Energy Sector, Publications Office of the European Union, 2021, https://data.europa.eu/doi/10.2833/006724; and Frost & Sullivan, Developments in Vehicle-to-Grid (V2G) Technology: Transformational Technology Influencing Electric Vehicles and Smart Grids, 2017.

increasingly modular nature of ADMS and DERMS products offers some freedom of choice for DSOs.

Table 5. European advanced distribution management systems (ADMS) and distributed energy resource management systems (DERMS) market

Company (year established)	Headquarters	Market share[19]	Description	DSO application examples
Hitacchi ABB (1988; 2020 merger)	Switzerland	ADMS: Medium DERMS:Medium	Partnering with Enbala (Canada), offers DERMS integrated with in-house ADMS	ADMS: Endesa (Spain)
General Electric (1892)	USA	ADMS: High DERMS:Medium	Offers modular applications as extension of ADMS (e.g. distributed energy resources management, volt-VAR control, load forecasting), stand-alone DERMS system for utilities and possibility to integrate with aggregators	ADMS: Iberdrola Distribución Eléctrica (Spain), Stedin (Netherlands)
Siemens (1847)	Germany	ADMS: Medium DERMS: Medium	Offers DERMS and four additional grid-management applications that can be integrated with Siemens's Spectrum Power ADMS	DERMS: Southern California Edison (USA)
Schneider Electric (1836)	France	ADMS: High DERMS: Medium	Partnering with AutoGrid (USA), offers DERMS as part of ADMS; can deploy supervisory control and data acquisition (SCADA), outage management system (OMS) and distribution management system (DMS) with DERMS, piecewise or integrated	ADMS: Enel (Italy)

[19] Market share estimate is from J European Commission, Directorate-General for Energy, *Digital Technologies and Use Cases in the Energy Sector*.

Company (year established)	Headquarters	Market share[19]	Description	DSO application examples
Oracle (1977)	USA	ADMS: Low DERMS: Unknown	Offers DERMS as module to Oracle Utilities Network Management System	Evergy (USA), NIE (Ireland), Louisville G&E/KU (USA)
Autogrid (2011)	USA	DERMS: Medium	Focuses on advanced data analytics of DER as well as demand response; integrates with ADMS; partners with Schneider Electric	National Rural Telecommunications Cooperative (NRTC) members: 800 rural electric utilities (USA)
Enbala Power Networks (2003)	Canada	DERMS: Medium	Offers DERMS without in-house ADMS; partners with ABB	New Brunswick Power (Canada), Eversource (USA)
Smarter Grid Solutions (2008)	UK	DERMS: Unknown	Offers DERMS Smarter Grid Solutions' Strata software without in-house ADMS, and comprehensive modular DERMS with possibility of DMS integration	Western Power Distribution (UK)

3.3 Stakeholder mapping for DERMS

Stakeholders for this business case include society, governments and energy-industry businesses.

Society. Consumers and citizens can benefit from DERMS as it enables non-wires alternatives to infrastructure expansion, reducing the land used and, because of the smaller grid, lowering network charges. VPP prosumers, or individual energy consumers who produce all or part of their own demand, can also benefit from a larger power-trading market.

Government. For the European Union and for national governments, DERMS allow the possibility of increasing power flexibility in distribution grids. Explicit stimulation of DERMS projects through financing may be able to help accelerate adoption in line with renewable energy growth expectations, contingent on the correct application of mechanisms, incentives and controls not covered in this report. The complexity of grids will inevitably increase, and with them the possibility of cyber threats to critical infrastructure. As a consequence, regulations for DERMS should consider the importance of cybersecurity. DSO cost and regulatory aspects may also need to be reassessed.

Business. Renewable energy developers and DERMS vendors would benefit from an increase in market activity due to higher penetration of RES. For DSO operators this would mean an increase in the complexity of grid operation, which could lead to higher operating costs, but it also represents an opportunity for additional business models and revenue to improve the management of distributed energy resources, making it easier to reach RES targets.

Analysis suggests low challenges for DERMS among stakeholders. Virtually all stakeholders agree on the need for high renewable energy and flexibility integration at the DSO level. One challenge

will be distributing costs among stakeholders, to ensure both full compliance with cybersecurity requirements and innovation, pilots and at-scale deployment.

3.4 Innovation assessment of DERMS

A qualitative assessment, based on expert interviews and literature review,[20] indicates that ADMS and DERMS innovation may encounter moderate challenges in Europe. Europe is well represented among established, traditional ADMS market players; DERMS players, however, are predominantly non-European, and the DERMS vendor environment is significantly more dynamic and innovative. Research in Europe focuses on the broad adoption of renewables into the power system, but not on the role and performance of DERMS specifically.

3.4.1 European innovation position of DERMS

The following aspects were taken into account while assessing innovation in Europe:

- *Market position of European firms.* European firms are moderately well positioned in the market. Four of the eight key market players are European, but most of their DERMS products are from non-European partners. Of European firms, only Siemens offers both ADMS and DERMS.
- *Share of European firms in the supplier and customer network.* Most ADMS suppliers are vertically integrated software and hardware developers and manufacturers. Four of the eight key ADMS market players are European, including three from within the European Union (counting Hitachi ABB, because it is part Swedish-owned, but excluding SGS in the United Kingdom).
- *Level of innovation in the European Union.* While the European Union funds research on distributed energy resources, funding explicitly for DERMS research is very limited. This applies both to DERMS system design and to pilot projects aiming to bring DERMS innovation into practice. Three of the four key DERMS market players are non-European, with most DERMS innovation taking place in the United States and Canada.
- *Enabling environments (research institutes, universities, think tanks).* Europe has high-quality research institutes with knowledge key to DERMS innovation. Due to limited DERMS-specific research funds, this research capacity is currently not directly leveraged, but the relevant institutes have a significant track record in VPP research and pilots, a topic very close to ADMS and DERMS challenges.

3.4.2 Spillover effects of DERMS

The following indirect benefits could emerge from DERMS innovation:

- *Reusability of infrastructure, data and research results.* DERMS infrastructure, data and research results can be reused to a limited extent as they largely leverage infrastructure specific to the power industry. Within the global power sector, reusability is high, as renewables will be adopted at varying rates throughout Europe and globally. This reusability provides an opportunity for knowledge export beyond Europe.
- *Transferability to other industries.* Application of ADMS/DERMS innovations beyond the power sector would logically include other critical infrastructure, like transport systems and buildings, because of the similarity of distributed data-gathering and control, high cybersecurity requirements and the possibly regulated nature of operations.

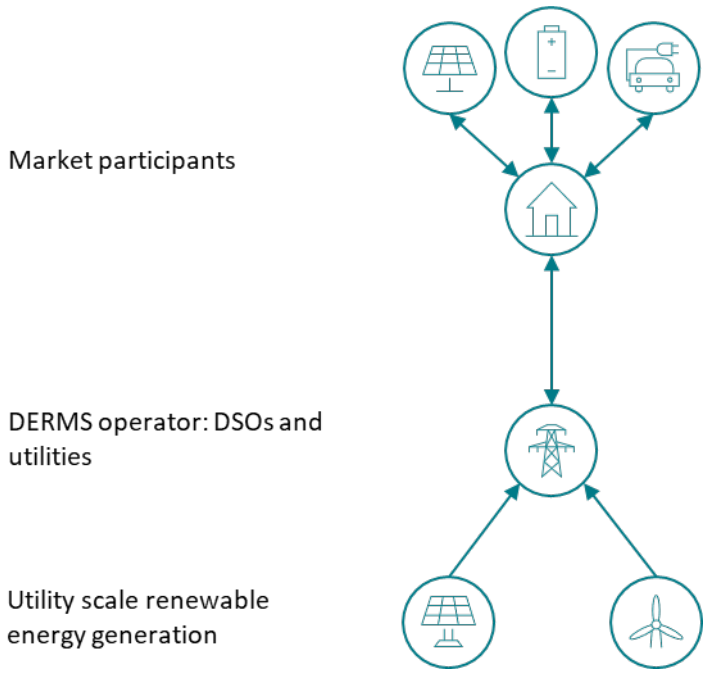
[20] European Commission, Directorate-General for Energy, Digital Technologies and Use Cases in the Energy Sector.

3.5 Economic assessment of DERMS

This section presents the main players associated with the DERMS business case – that is, those primarily expected to implement it – and explores its economic viability for them[21]. Figure 10 shows a schematic of the power and energy flow for this business case as well as the relevant players in each step.

Market participants are stakeholders on the grid edge – that is, residential consumers, VPPs (which aggregate distributed-renewable generation) and possibly new downstream players like power and energy service companies (ESCOs). Integrating the various ways market participants interact with the grid is a key task of DERMS. Because business models for ESCOs and other market participants are still undergoing significant innovation and development, the requirements for integration are evolving. This creates a challenge for both market participants and DERMS operators.

Figure 10. The power and energy flow for the DERMS business case



Typically, the local DSO or integrated utility acts as DERMS operator. The key challenges for DERMS operators arise from integration at scale, successful energy resource management using DERMS, and the development and accommodation of new business models enabled by DERMS.

Renewable energy systems are also an indirect stakeholder in the DERMS business case. Inherently variable levels of power generation (from market participants and utility-scale renewables) require balancing, which is at the core of DERMS operations. As a result, renewable energy generation is positively affected by DERMS system integration as higher levels of renewable energy can be accepted into the power system.

DERMS will play a vital role in the integration of flexibility from distributed energy resources, but analysis suggests challenges in making the business case for DERMS from the perspective of direct

[21] Ibid.

returns. Instead, the viability of DERMS lies in their ability to integrate higher levels of renewable generation into the power grid – a goal in itself for national governments.

3.5.1 DERMS Revenue

Because DERMS do not necessarily generate revenues on their own, but rather enable other revenue-generating business cases, revenue estimates for this business case are not assessed in this report.

3.5.2 Total cost of ownership for DERMS

The total cost of ownership (TCOO) is the sum of annualised capital expenses (CAPEX) and yearly operating expenses (OPEX). If applicable, OPEX is split into fixed and variable expenses.

DERMS cost estimates in this Chapter are based on published data from two US utilities: National Grid Rhode Island and the Long Island Power Authority[22]. Their system costs are similar on a per-megawatt basis, which may be linked to the small pool of system vendors globally.

When comparing business-case TCOO keep in mind that DERMS do not provide flexibility to the European power system but enable the integration of it.

Table 6 shows how the annualised CAPEX and annual OPEX costs are calculated.

Annualised CAPEX is calculated using the following assumptions:

- equipment lifetime of 15 years
- no significant hardware installation for field equipment[23]
- 20% of ADMS cost can be attributed to DERMS functionality and is included in the cost of DERMS

While DERMS can function as stand-alone systems, optimal benefits can be expected through integration with ADMS. ADMS integrate four or five other major systems, including GIS, distribution supervisory control and data acquisition (SCADA), outage management, two-way communications, and so forth; hence we assume 20% of ADMS cost directly relates to DERMS. This applies to both the CAPEX and OPEX aspects of the TCOO calculation.

Table 6. CAPEX and OPEX as part of TCOO calculations for DERMS

Capital expenses (CAPEX)	Cost range		Unit
	Minimum	Maximum	
DERMS system purchase[24]	3,800	5,300	EUR/MW
20% of ADMS system cost for optimal DERMS integration[25]	9,100	12,700	EUR/MW

[22] Ibid.; Narragansett Electric Company, dba National Grid (Rhode Island), *Grid Modernization Plan*, January 2021, http://www.ripuc.ri.gov/eventsactions/docket/5114-NGrid-Modernization%20Plan%20(PUC%201-21-2020).pdf; and Long Island Power Authority, *Powering Long Island's Energy Future: 2021 Budget*, 2020, https://www.lipower.org/wp-content/uploads/2020/12/LIPA_2021-Budget-12-14.pdf.

[23] European Commission, Directorate-General for Energy, Digital Technologies and Use Cases in the Energy Sector.

[24] Ibid.

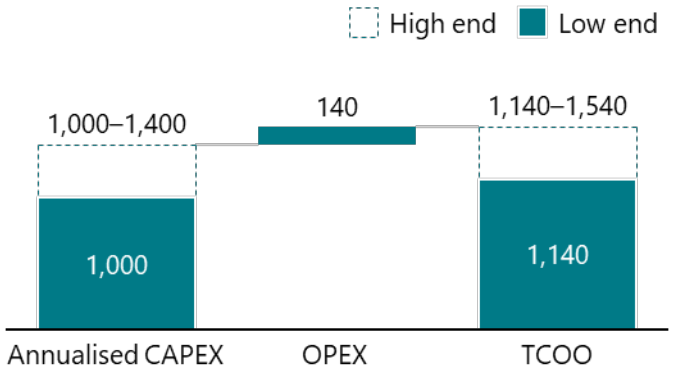
[25] Ibid.

Capital expenses (CAPEX)	Cost range		Unit
	Minimum	**Maximum**	
Total annualised CAPEX	**880**	**1,200**	**EUR/MWYE[26]**
Operating expenses (OPEX)		Cost range	
	Minimum	**Maximum**	
Fixed cost: DERMS, operations and maintenance (O&M), including licenses[27]	40	n/a	EUR/MWYE
Fixed cost: 20% of ADMS O&M	100	n/a	EUR/MWYE
Annual OPEX	**140**	**n/a**	**EUR/MWYE**

The total cost of ownership for DERMS procurement, integration and operation is around EUR 1,140 to EUR 1,540 per megawatt per year (see Figure 11 for a breakdown of this cost).

Another consideration is that two examples of indirect benefits for DSOs have been reported in the literature: First, better grid operations using DERMS could reduce fines from voltage, overload and backload violations. In 2018, for example, the California DSO PG&E reported a 95% reduction in violation costs after installing DERMS[28]. Second, DERMS can achieve higher levels of grid capacity through better orchestration of DER power flows, providing DSOs with an alternative to traditional capital projects for capacity expansion, also known as non-wires alternatives. Scotland's Smarter Grid Solutions (SGS) estimates that scaling up the DERMS system Active Network Management Strata software to all six UK DSOs will free up 2 gigawatts and save GBP 250 million[29].

Figure 11. Total cost of ownership for DERMS, EUR/MWYE



3.6 Technical assessment of DERMS

As DERMS themselves do not add or limit flexibility performance, no technical assessment is made for them. The ability to provide flexibility depends on the business cases that are integrated through DERMS, such as VPPs, vehicle-to-grid and so forth.

[26] Megawatt-year

[27] Pacific Gas and Electric Company, *Electric Program Investment Charge (EPIC) Final Report*, EPIC 2.02 – Distributed Energy Resource Management System, January 2019, pge-epic-2.02.pdf, available at https://www.pge.com/en_US/about-pge/environment/what-we-are-doing/electric-program-investment-charge/closeout-reports.page.

[28] Ibid.

[29] "UK's Western Power Distribution to deploy SGS ANM Strata software," *Power Technology*, September 17, 2018, https://www.power-technology.com/news/uks-western-power-distribution-deploy-sgs-anm-strata-software/.

3.7 Technical infrastructure required for DERMS

The technical infrastructure needed to implement this business case is divided into three categories: analog, digital and analytics.

Analog. From an analog perspective, infrastructure is needed to improve the physical grid integration. DERMS must be asset-hardware agnostic to ensure safe and reliable integration for remote operational controls[30].

Digital. On a digital level, real-time grid operations require visibility of the network state through ADMS-DERMS interaction[31], and operational controls require the ability to enrol additional DER[32]. Integration of operational forecasts is critical and strongly linked to the provision of market-trading agreements via IT systems integration[33]. DSO/TSO stability-services integration are also required, to provide accurate power measurement and verification, settlement and record keeping of DER participation in network control[34].

Analytics. Analytics and storage of historical data are needed to optimise the performance of DERMS and to forecast operational margin issues.

This technical infrastructure may face moderate challenges, given that thousands to possibly millions of DER connections from an increasingly large vendor landscape must be integrated safely and reliably for real-time operations, and millions of customer accounts must be integrated to enable financial transactions.

3.8 DERMS risk considerations

Cybersecurity is the main risk in implementing DERMS, although legal issues and public and operator acceptance should also be considered. These risks are considered moderate, though they would likely need significant resolution effort:

- *Varying standards*. Some in the industry would like to see the Euroepan Union introduce regulatory requirements for non-wires alternatives[35]; there are currently few regulations in place regarding DSO implementation of DERMS in regard to granular hosting capacity visibility and optimising DER integration as a non-wires alternative.
- *Cybersecurity*. Both the research corporation American Environmental Energy Inc. (AEEI) and the stakeholder group the European Smart Grids Task Force point out that as more consumer data from authenticated, connected devices becomes necessary, increased use of third-party cloud

[30] European Smart Grids Task Force (Expert Group 3), *Final Report: Demand Side Flexibility: Perceived Barriers and Proposed Recommendations*, European Commission, April 2019, https://ec.europa.eu/energy/sites/ener/files/documents/eg3_final_report_demand_side_flexiblity_2019.04.15.pdf.

[31] Advanced Energy Economy Institute (AEEI), *Cybersecurity in a Distributed Energy Future: Addressing the Challenges and Protecting the Grid from a Cyberattack*, January 2018, https://info.aee.net/aee_institute_cybersecurity.

[32] Advanced Energy Economy Institute (AEEI), *Cybersecurity in a Distributed Energy Future*; and European Smart Grids Task Force, Expert Group 3, *Final Report: Demand Side Flexibility – Perceived barriers and proposed recommendations*, April 2019, https://ec.europa.eu/energy/sites/ener/files/documents/eg3_final_report_demand_side_flexibility_2019.04.pdf

[33] European Commission, Directorate-General for Energy, *Digital Technologies and Use Cases in the Energy Sector*.

[34] AEEI, Cybersecurity in a Distributed Energy Future.

[35] Karoline Steinbacher and Tim Stanton/Navigant, "Non-wires alternatives for grid expansion: What the US can teach Europe," *Energy Post*, October 18, 2019, https://energypost.eu/non-wires-alternatives-for-grid-expansion-what-the-u-s-can-teach-europe/.

services will require the full compliance of vendors[36]. Common operating systems for transport-layer security in DER would lower the risk, but such systems are currently lacking.

Public and operator acceptance. Because of complex control-system capabilities and many integration points, DERMS are costly, and that may slow their adoption, reducing the ability of DSOs to integrate DER at scale. The high cost could also jeopardise the quality of integration through lowered cybersecurity spending. And while CAPEX cost could be avoided through the use of DERMS and ADMS, digital grid infrastructure is required in addition to software[37].

The low risk in public and operator acceptance, which can be resolved relatively easily, is that an increasingly complex operating environment will require adoption of data-quality and data-integrity standards such as connectivity-model corrections. No major gamification risks have been identified.

Another potential moderate risk is in rolling out DERMS, because of their significant reliance on third-party systems for both hardware and software. DERMS will likely play a critical role in maintaining the stability of power systems with high levels of variable renewable energy.

[36] European Smart Grids Task Force, *Final Report*.

[37] Ibid., and European Commission, Directorate-General for Energy, *Digital Technologies and Use Cases in the Energy Sector*.

4 Use case: Virtual power plants

According to the Green Deal, the development of a power sector largely based on renewable energy sources (RES) is key to achieving climate neutrality in Europe by 2050[38]. Renewable energy is usually generated by a large number of small, distributed devices, such as wind turbines, PV systems and small combined heat and power (CHP) plants that use biomass. Individually, these distributed energy resources (DERs) are too small to participate economically in flexibility markets; they are instead used to provide the unchanging demand on an electrical grid known as baseload power. However, using information and communication technologies (ICT) to aggregate DERs into virtual power plants (VPPs) allows them to participate in flexibility markets with a higher market value per megawatt hour.

In terms of flexibility, VPP DERs fall into two categories: variable DERs, such as wind turbines and PV systems, whose generation depends on weather conditions, increasing the need for flexibility, and dispatchable DERs, such as CHP plants and batteries, whose generation can be ramped up and down more or less freely[39]. The generation of variable DERs can also be ramped down and, if not running at maximum capacity (pre-curtailment), ramped up, but because ramping is accompanied by a loss of renewable energy, it is not considered flexibility for the purposes of this report. Other flexibilities excluded from the VPP business cases include large-scale power plants, because they can act in flexibility markets without being integrated into VPPs, and energy storage systems, because they are the focus of other business cases. Therefore, the business cases in this Chapter, all part of the virtual power plants use case, analyse the flexibilities of biomass, waste incineration and small CHP plants that are gas-fired using natural gas, biogas, hydrogen or a mix.

The business cases shown in Table 7, which use dispatchable DERs for flexibility in VPPs, are derived from the usual market participation and usage options of VPPs.

Table 7. VPP business cases

VPP business case	Assumed dispatchable capacity by 2050 (GW)	Day-ahead dispatch priority
VPPs for internal balancing	164	1
VPPs for balancing reserves	16	2
VPPs for intraday spot market	80	3

The three business cases analysed in this Chapter have a day-ahead dispatch priority in ascending order: internal balancing, reserve balancing, and spot market trading. Internal balancing is the first priority, because VPP operators must prioritise it to ensure day-ahead obligations are met[40]. Current

[38] European Commission, "A European Green New Deal – Striving to be the first climate-neutral continent," n.d., https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal_en.

[39] Regarding power consumption, VPPs in the US are more commonly associated with electricity production, demand-side response and other load-shifting approaches, whereas in Europe they are predominantly used for generation.

[40] Elia, *Day-Ahead Balance Obligation of the Balance Responsible Parties*, public consultation, September 22, 2020, https://www.elia.be/-/media/project/elia/elia-site/public-consultations/2020/20200922_external-report-da-balance-obligation-study-final_en.pdf?la=en.

regulations and typical market prices generally apply flexibility to VPPs for balancing reserves next, because higher prices make them more attractive than spot market trading, which is the lowest priority for day-ahead dispatch.

The 2030 and 2050 scenarios assume that dispatchable DERs in VPPs will still be able to provide baseload power or participate in flexibility markets. For this reason, and especially because CHP plants also supply heat, it is assumed that dispatchable DERs in VPPs are not purpose-built for power flexibility – so for the three business cases covered in this Chapter, the CAPEX and OPEX of plant operations have been excluded, and the focus is on the hardware and software.

4.1 Market overview for VPP

VPP participation in spot and balancing markets, already well established in Europe, is growing rapidly. A 24% compound annual growth rate is projected by 2030, and the market is expected to continue growing beyond that as DERs are more widely adopted[41]. Germany is today the most mature market in the European Union, and it is transparent in terms of market-share data, as shown in Table 8.

Table 8. The top three VPP players in the German market 2020[42] by total market share

Company	Headquarters	Total market share	Description
Statkraft	Norway	22%	9.9 GW traded only on German energy markets: 93% wind, 6% PV, 1% hydro. Approximately 100 megawatts of dispatchable capacity.
Next Kraftwerke	Germany	13%	5.8 GW traded only on German energy markets: 9% wind, 61% PV, 27% bioenergy, 2% CHP. Approximately 1,680 megawatts of dispatchable capacity.
E.ON	Germany	10%	4.5 GW traded only on German energy markets: 63% wind, 32% PV, 4% bioenergy, 1% hydro. Approximately 225 megawatts of dispatchable capacity.

Key players in the VPP market are dedicated VPP developers such as Next Kraftwerke and established power generators like Statkraft, E.ON, Enel and Enel X. Smaller players are established power-system original equipment manufacturers (OEMs), including ABB, Honeywell, Siemens and Schneider Electric. Virtually all VPP companies working in the European Union are European.

Because VPPS represent a strong growth market with a large variety of players, analysis shows low challenges in the competitive landscape.

[41] European Commission, Directorate-General for Energy, *Digital Technologies and Use Cases in the Energy Sector*.

[42] ZFK, "ZFK-Umfrage 2020 zur direktvermarktung von erneuerbaren und KWK," 2020, https://www.zfk.de/fileadmin/Bilderdatenbank_NEU/Grafiken/marktueberblick_direktvermarktung_2020_02.pdf.

4.2 Stakeholder mapping for VPPs

Stakeholders for this use case include society, government, business and the environment.

Society. Local communities may be positively impacted by an influx of ICT and tech jobs, and community-owned VPPs provide earnings opportunities for shareholders. More community-owned VPPs could benefit from simplified participation agreements.

Government. For both EU and national governments, more dispatchable renewable energy sources aggregated in VPPs could improve grid stability, though that would also increase exposure to cybersecurity threats. A Europe-wide standardisation of protocols and ICT security requirements could be considered to address that risk, especially for reserve-balancing VPPs.

Business. At the business level, VPP operators may accrue additional revenue by participating in flexibility markets, but on the spot market, exposure to intraday price fluctuations may have an adverse impact. Providers of VPP technologies may also benefit from innovations.

Environment. VPPs can have a positive impact on the environment by supporting the phasing out of fossil fuels for baseload electricity generation.

Overall, stakeholder challenges appear to be low for VPP participation in flexibility markets. The VPP business cases are mature and common practice in Germany, the United Kingdom, and, to some extent, France, with growth projected in other countries in the European Union.

4.3 Innovation assessment of VPPs

This section is a qualitative assessment of the innovation position of the European Union based on expert interviews and literature review.

Overall, analyses have not identified major challenges in the innovation landscape for the participation of VPPs in flexibility markets in the European Union. From a power-generation perspective, Europe has highest deployment of VPPs, and Germany leads in VPP innovation[43]. By contrast, VPPs in the United States predominantly focus on electricity consumption.

4.3.1 European innovation position of VPPs

The following aspects were taken into account while assessing innovation in Europe:

- *Market position of European firms*. Europe is at the forefront of VPP applications, both dispatchable and intermittent RES. Europe accounts for approximately 42% of the worldwide installed VPP capacity[44], and virtually all key players in the European market are of European origin.
- *Share of European firms in the supplier and customer network*. Virtually all operators of VPPs in Europe are European, and they range from traditional power generators such as Statkraft and E.ON to established technology providers like ABB, Schneider Electric and Siemens.
- *Level of innovation in the European Union*. The European Union has historically played a leading role in VPP innovation starting as early the turn of this century, with projects such as the virtual fuel cell power plant, which consists of decentralised residential fuel-cell cogeneration systems; Power Matcher architecture, which "facilitates implementation of standardised, scalable Smart Grids, that can include both conventional and renewable energy sources"; Fenix, the "Flexible Energy Network to Integrate the eXpected 'energy evolution'"; the EDISON project, an EV

[43] Navigant Research, *Transforming Markets for VPPs in Europe: Flexibility and Trading Use Cases Grow in Sophistication and Scale*, commissioned by Embala, Guidehouse, 2019, https://www.caba.org/wp-content/uploads/2020/06/IS-2020-76.pdf.

[44] The 42% Figure is from Navigant Research, *Virtual Power Plant Enabling Technologies*, 2016; see European Commission, Directorate-General for Energy, *Digital Technologies and Use Cases in the Energy Sector*, for key players.

platform launched by a consortium of energy companies, technology suppliers and research labs and institutes; and Web2Energy, which aims to implement the three pillars of smart distribution (remote control and automation, aggregation of distributed energy resources and decentralised energy management) and institute smart metering to support the involvement of consumers into the electricity market. More recent innovations include EU-SysFlex, a "Pan-European system with an efficient coordinated use of flexibilities for the integration of a large share of RES"; community-based VPPs, or cVPPs; VPP4Islands, which works with virtual energy storage and distributed ledger technology; and edgeFLEX, a 5G-supported project that enables a new market for ancillary services through dynamic service-to-grid operations[45].

Enabling environments (research institutes, universities, think tanks). A significant number of institutes are collaborating on VPP projects across Europe, mostly under the EU umbrella. Examples include Fraunhofer IEE, Eindhoven University of Technology, Aix-Marseille University, Brunel University London, University of Bologna, RWTH Aachen University and University College Dublin, among others.

4.3.2 Spillover effects of VPPs

The following indirect benefits could emerge from VPP innovation:

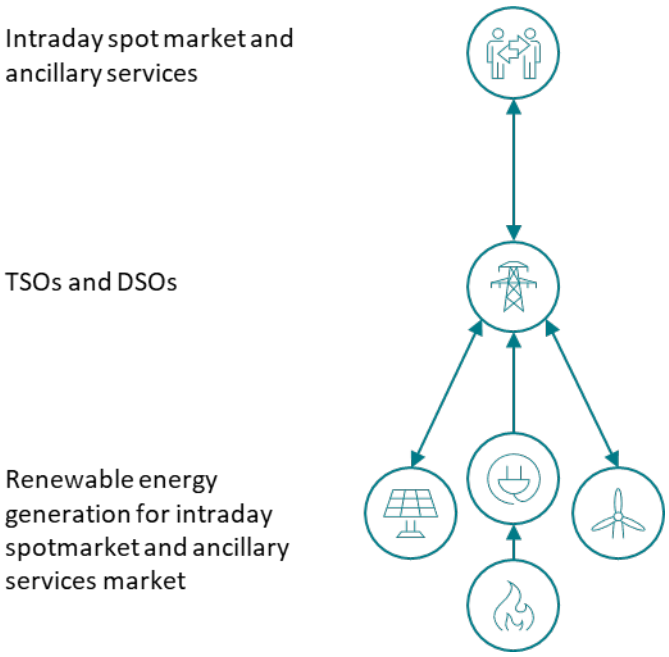
- *Reusability of infrastructure, data and research results.* VPPs reuse existing infrastructure and trading principles.
- *Transferability to other industries.* Industries with the most potential for transferability of protocols and cybersecurity measures are those associated with demand-side response.

4.4 VPPs revenue

This section discusses the main players associated with the VPP use case – that is, those expected to primarily implement it – and explores its economic viability for them. Figure 12 shows a schematic of the power and energy flow for this business case as well as the players relevant in each step.

[45] Information on the projects listed in this paragraph can be found in the following sources: "Virtual fuel cell power plant," http://www.hydrogenambassadors.com/background/images/vpp.pdf, available in Arno A. Evers, *The Hydrogen Society: More Than Just a Vision?,* April 2010, 125, Fig. 6.3, http://www.hydrogenambassadors.com/the-hydrogen-society-more-than-just-a-vision.html; "Why PowerMatcher?," Flexiblepower Alliance Network, 2017, http://flexiblepower.github.io/why/powermatcher/; "Fenix solution," Fenix, n.d., http://www.fenix-project.org/; Massimo Celidonio et al., "The EDISON project: Enhanced energy saving solution for lighting using DC power supply," *2013 IEEE Online Conference on Green Communications*, October 2013, https://ieeexplore.ieee.org/document/6731043; Bernd M. Buchholz and Zbigniew A. Styczynski, "The three pillars of smart distribution," in *Smart Grids*, 2020, 225–78, https://link.springer.com/chapter/10.1007/978-3-662-60930-9_6; EU-SysFlex, https://eu-sysflex.com/; and edgeFLEX, https://www.edgeflex-h2020.eu/.

Figure 12. Power and energy flow for the virtual power plants business case

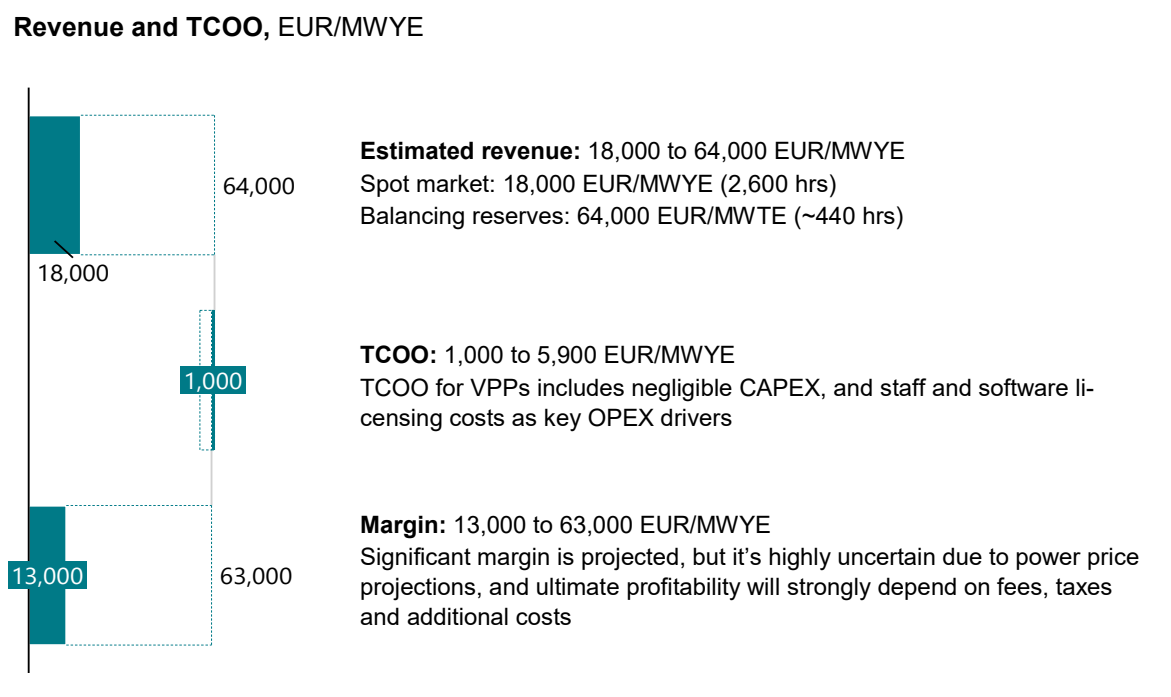


The spot and balancing reserve markets link supply and demand on timescales typically from seconds to hours.

TSOs and DSOs operate power transmission and distribution grids, respectively, and require spot market volumes for countertrading or procurement of grid losses. System operators require balancing reserves for frequency balancing.

VPPs operate renewable power generation capacity and require dispatchable capacity to compensate for the intermittent feed-in of RES like solar and wind. VPPs for internal balancing use CHP plants to meet day-ahead generation as agreed; the rest of the dispatchable power is traded for ancillary services or spot markets. The estimation of revenue and TCOO is shown in Figure 13.

Figure 13. Estimated operating margin for VPPs



Analysis suggests moderate challenges in the viability of VPP participation in spot and balancing reserve markets. VPP participation in power markets is mature in Germany, the United Kingdom and France. Viability is highly dependent on differences in power price spread, fees and taxes across EU member states. While revenues look positive, this assessment is highly uncertain because it's difficult to estimate underlying power prices.

4.5 Total cost of ownership for VPPs

Key assumptions for calculating TCOO can be found in Table 9. Compared with other Chapters in this report, a higher level of detail is included in the TCOO calculation of VPPs to provide greater transparency on how cost-scaling assumptions are applied; for example, some cost drivers scale by gigawatt capacity, by year, or by distributed energy resources or VPPs.

The CAPEX and OPEX depend on further assumptions, namely:

- equipment lifetime (set to 10 years)
- between 60 and 660 VPPs in Europe by 2030
- 1,200 to 3.2 million dispatchable DER in VPPs in Europe by 2030

The estimated range of the number of VPPs in Europe 2030 is based on the German situation in 2020, where there were 20 VPPs with 4.8 gigawatts dispatchable capacity[46]. The estimate of 60 VPPs by 2030 derives from the assumption that Germany will capture about a third of Europe's VPP market by 2028[47], assuming a constant number of VPPs and an increase in dispatchable capacity for each. The estimate of 660 VPPs by 2030 derives from scaling up the 4.8 gigawatts dispatchable capacity to 160 gigawatts, assuming an increase in the number of VPPs with a constant dispatchable capacity. The 160 gigawatts is in line with the 360 gigawatts expected in Europe by 2050[48].

[46] ZFK, "ZFK-Umfrage 2020 zur direktvermarktung von erneuerbaren und KWK."

[47] European Commission, Directorate-General for Energy, *Digital Technologies and Use Cases in the Energy Sector*.

[48] Open energy platforms at https://openenergy-platform.org/dataedit/view/scenario/fh_iee_trafo_fw_wenig_dez_bio_mod_sani_strom_bilanz,

The estimate of dispatchable DERs in VPPs assumes capacities of less than 50 kilowatts for micro-CHP plants and 100 megawatts for large DERs. A dispatchable VPP capacity in Europe in 2030 of 120 to 160 gigawatts results in a range of 1,200 to 3.2 million dispatchable DERs. The lower cost limits in Table 9 apply to microgenerators, and the upper cost limits to large generators. The possible obligation for redundant ICT hardware in the balancing reserve business case requires a doubling of costs for servers, additional hardware at plant level and an additional network connection.

Table 9. Cost of flexibility for VPPs (2021)[49]

Capital expenses (CAPEX)	**Cost range**		**Unit[50]**
	Minimum	**Maximum**	
Hardware: application, monitoring and optimiser servers	25,500	38,250	EUR/GW
Hardware: database server	3,400	5,100	EUR/VPP
Hardware: communication box	0	850	EUR/DER
VPP integration: forecast provider	0	16,800	EUR/DER
Total annualised CAPEX	**15**	**24**	**EUR/MWYE**
Operating expenses (OPEX)			
Hardware: network connection	0	170	EUR/DERYE
VPP integration: interface driver	0	8,400	EUR/VPPYE
Software: optimiser license	0	17,000	EUR/VPPYE
Software: VPP license	17,000	170,000	EUR/VPPYE
Forecasting module: wind forecast	43	850	EUR/MWYE
Forecasting module: PV forecast	43	850	EUR/MWYE
Staff (VPP back office and control centre)	60,000	60,000	EUR/FTEYE
Market access	0.01	0.06	EUR/MWh
Total OPEX	**998**	**4,845**	**EUR/MWYE**

The costs of market access cover expenses for market entry and trading fees, an energy trading system and an energy data-management system.

Regarding application, monitoring and optimiser servers, it can be estimated that one database server can process up to about 3 gigawatts. Further assumptions are that each VPP uses up to three servers, that 10 to 15 interface types have to be updated every year, that up to three forecast providers are used by each VPP, and that each VPP requires a staff of 15 to 30 persons per gigawatt.

Taking all these assumptions into account, the total cost of ownership is approximately EUR 1,000 to EUR 4,900 per megawatt per year (MWYE), as shown in Figure 14.

Based on the above range, a TCOO of EUR 2,950 per megawatt year is used for market-size estimations.

https://openenergyplatform.org/dataedit/view/scenario/fh_iee_trafo_fw_wenig_dez_bio_mod_sani_strom_erzeugung and https://openenergy-platform.org/dataedit/view/scenario/fh_iee_trafo_fw_wenig_dez_bio_mod_sani_speicher.

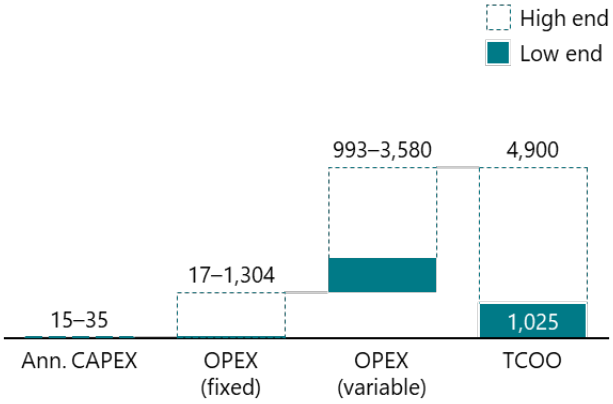
[49] Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ), *Opportunities for Virtual Power Plants in India*, October 2019, https://www.energyforum.in/fileadmin/user_upload/india/media_elements/publications/20191121_Virtual_Power_Plants/Virtual_Power_Plants__Report.pdf.

[50] MWYE: per MW per year, DERYE: per DER per year, VPPYE: per VPP per year, FTEYE: per FTE per year

Other points to consider:

- Larger VPPs can have larger profit margins, because a significant part of the OPEX can be independent of capacity/generation, including, for example, VPP control-centre personnel or optimiser licenses.
- Cost of hardware integration is assumed to be negligible on the low end, as by 2050 all DER hardware should come with basic communication capabilities for smart-grid integration.
- Key OPEX drivers include personnel and VPP licensing costs, so larger VPPs will have benefits of scale.
- Overall, analysis suggests low challenges in the economics of VPPs, as many costs for central control are incurred only once and the costs for distributed assets are comparatively low. TCOO is largely driven by operating costs of staff and licensing.

Figure 14. Total cost of ownership for virtual power plants, in euros per megawatt-year



4.6 Technical infrastructure required for VPPs

The technical infrastructure needed to implement VPPs at any site is divided into three main categories, with some overlap: analog, digital and analytics.

Analog. From an analog perspective, DER integration into VPPs generally requires a hardware communication system at every DER site. For a wind or solar farm, one central communication system can be sufficient if the turbines or inverters are connected to it by a designated telecommunication network. The same principle can be applied for mixed assets behind a common grid coupling point, where all DER assets can be controlled remotely by a single control unit. For data acquisition and, if available, remote control, an advanced metering infrastructure can be applied to complement or replace traditional on-site solutions like proprietary gateways or additional DER controllers, if it can be linked bidirectionally. A frequency meter at or near a DER site is necessary if the VPP wants to provide a frequency containment reserve[51].

Digital. On a digital level, operation energy management systems are used to optimise asset scheduling in VPPs using a separate server in addition to the application, database and monitoring servers. To enable energy management systems optimisation as well as additional trading and unit dispatching, forecast systems are integrated into VPPs. For this integration and the integration of other IT systems, a secure communication infrastructure is used to connect DER for remote control and data accessibility.

Analytics. For analytics, energy-trading systems provide interfaces to the various flexibility markets. Energy data-management systems are used for handling market data.

[51] For more information on VPP architecture, see GIZ, *Opportunities for Virtual Power Plants in India*.

Overall, analyses suggest moderate technical infrastructure challenges to delivering VPP flexibility. Focusing on fewer core standards can decrease the cost of integrating DER into VPPs. A Europe-wide high-performance ICT network could enable large-scale deployment of VPPs, but the underlying infrastructure of VPPs must steadily increase their resilience to handle security threats. Europe-wide standardisation of protocols and ICT security requirements could address the cybersecurity risk.

4.7 VPPs risk considerations

Potential risks could be experienced in relation to non-compliance, cybersecurity and gamification potential.

Non-compliance. VPP operators could violate the obligation to comply with the day-ahead schedules through VPP internal balancing and could bet on low imbalance settlement prices, leaving a capacity gap. In June 2019, Germany required a last-minute import from abroad due to significant negative deviations in the energy balance[52]. This was resolved in Germany by adjusting regulations, but it may remain relevant for other countries.

Cybersecurity. VPP's dependence on information and communications technology raises the risk of cyberattack. Since the successful cyberattack on a power grid in Ukraine in 2015, vulnerabilities in energy systems have been exploited several times, and experts warn the threat remains[53].

Gamification potential. Risk could arise if overall generation capacity were concentrated in a few VPPs. Monopolies could arise to collaborate on intraday prices. One such agreement already took place, in the early 2000s[54]. Regarding balancing reserve VPPs, without an energy price cap for frequency restoration reserve (FRR), very high prices could have an impact on other rates, such as those for imbalance settlements. This situation led to an abuse of the FRR market system in Germany in 2017[55].

Existing cybersecurity standards and regulations have so far kept the risks low, and they are expected to be kept up to date. Nevertheless, the increasing interaction between operational and information technologies could benefit from the introduction of new concepts like the resilience approach, which copes with disruptive events so that the system will not collapse and returns it to a normal state when the crisis is over[56].

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[52] *Investigation on System Imbalances in Germany in June 2019*, report from November 19, 2019, August 2019, allemagneenergiesdotcom.files.wordpress.com, https://allemagneenergiesdotcom.files.wordpress.com/2019/07/study-balancing-state-june-2019.pdf.

[53] Jim Magill, "Experts say cyberattacks likely to result in blackouts in US," *Forbes*, July 24, 2021, https://www.forbes.com/sites/jimmagill/2021/07/24/experts-say-cyberattacks-likely-to-result-in-blackouts-in-us/?sh=632e06d4372d; and Kim Zetter, "Inside the cunning, unprecedented hack of Ukraine's power grid," *Wired*, March 3, 2016, https://www.wired.com/2016/03/inside-cunning-unprecedented-hack-ukraines-power-grid/; Ilaria Grasso Macola, "The five worst cyberattacks against the power industry since 2014," *Power Technology*, April 2, 2020, https://www.power-technology.com/features/the-five-worst-cyberattacks-against-the-power-industry-since2014/; and David Stringer and Heesu Lee, "Cybersecurity: Why global power grids are still vulnerable to cyberattacks," Bloomberg, March 3, 2021, https://www.bloomberg.com/news/articles/2021-03-03/why-global-power-grids-are-still-so-vulnerable-to-cyber-attacks.

[54] Commission of the European Communities, Commission Decision of November 26, 2008, Relating to a proceeding under Article 82 of the EC Treaty and Article 54 of the EEA Agreement, https://ec.europa.eu/competition/antitrust/cases/dec_docs/39388/39388_2796_3.pdf.

[55] Jan de Decker, Elias De Keyser, and Paul Kreutzkam, "Lessons learnt from Germany's mixed price system," Next Kraftwerke, July 23, 2019, https://www.next-kraftwerke.com/energy-blog/lessons-reserve-power-market.

[56] Christoph Mayer and Gert Brunekreeft, *Resilienz Digitalisierter Energiesysteme: Blackout-Risiken Verstehen, Stromversorgung Sicher Gestalten*, Leopoldin, Schriftenreihe Energiesysteme der Zukunft, February 2021, https://www.acatech.de/publikation/rde-analyse/download-pdf?lang=de.

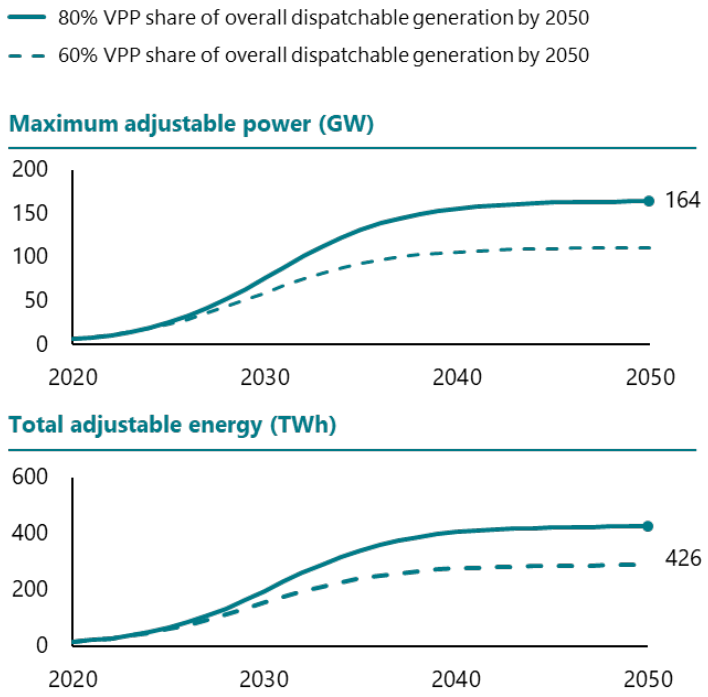
4.8 Business case: VPPs for spot markets

4.8.1 Potential time frame for VPPs for spot markets impact

VPPs will likely be the main power plants in the future as increasing digitalisation meets the strong expansion of distributed renewable energy sources to meet climate targets. Europe's first commercial VPP started operation in 2012; growth is projected to be 24% by 2030, and it is expected to continue well beyond that, albeit in a weakened form[57]. Assuming 80% growth, dispatchable capacity from VPPs in the European Union should be at 360 gigawatts by 2050[58]. 260 gigawatts of that will come from the top three applications – internal balancing, balancing reserves and spot-market trading – with 164 gigawatts coming from spot-market VPPs alone. The uptake to 164 GW of VPPs for the intraday spot market is shown in Figure 15.

Participation of dispatchable renewable energy resources in VPPs is expected to be between 60% and 80%. The total adjustable energy is calculated using the 2,600 annual full-load hours of district heating CHPs, which are limited by thermal requirements.

Figure 15. Impact of flexibility of virtual power plants for spot markets on the European energy system



There will likely be low challenges in the adoption of VPPs for spot-market participation. Across Europe (including the United Kingdom, Switzerland and Norway) VPP capacity is growing fast, and spot market participation is a part of that growth. An uncertainty regarding the final dispatchable

[57] Adrian Gligor et al., "Challenges for the large-scale integration of distributed renewable energy resources in the next generation virtual power plants," *Proceedings* 63, no. 1, December 11, 2020, https://doi.org/10.3390/proceedings2020063020 and European Commission, Directorate-General for Energy, *Digital Technologies and Use Cases in the Energy Sector*.

[58] Open energy platforms at https://openenergy-platform.org/dataedit/view/scenario/fh_iee_trafo_fw_wenig_dez_bio_mod_sani_strom_bilanz, https://openenergyplatform.org/dataedit/view/scenario/fh_iee_trafo_fw_wenig_dez_bio_mod_sani_strom_erzeugung and https://openenergy-platform.org/dataedit/view/scenario/fh_iee_trafo_fw_wenig_dez_bio_mod_sani_speicher.

VPP capacity size is the future size of dispatchable plants across Europe; large plants will likely operate outside VPPs.

4.8.2 VPPs for spot markets revenue

Revenue is calculated based on the 2030 European average hourly price curve used for other business cases, which is derived from an energy-system model that considers wholesale-based hourly electricity demand and supply from a power mix that includes conventional and renewable energy sources as well as batteries. Transmission (and therefore congestion) is regarded between countries only. The analysis of revenue in this business case and throughout this report should be considered an illustrative exercise rather than a prediction on the evolution of price over time.

Each business case is regarded independently and incrementally (i.e. assuming a small amount of implementation that does not affect prices).

The calculation for this business case is based on assumptions about heating requirements from CHP, which are reflected in a maximum interval length in which a certain amount of power needs to be produced. With the parameters set, the interval length is six hours, taking into account that a duration of no production at the end of one interval adds onto a duration of no production at the beginning of the next interval, and in sum may not be more than 8.5 hours. During each interval, 1.8 hours must be produced, and those hours with the highest price are chosen for production.

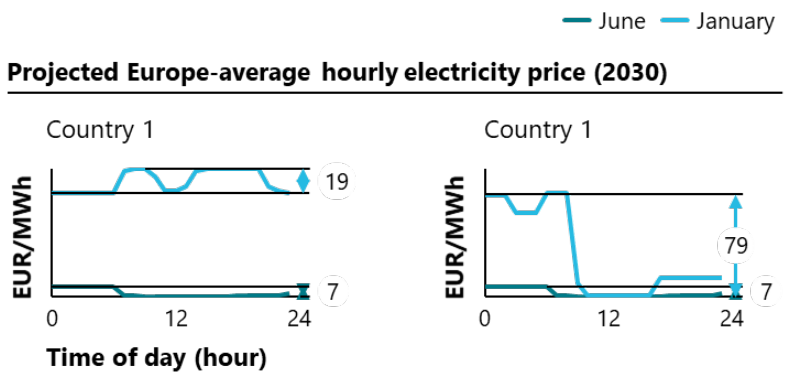
The following parameters were used:

- number of hours to run per year: 2,600
- approximate maximum flexibility duration: 8.5 hours
- interval length: 6 hours
- run time per interval: 1.78 hours

Based on these parameters and the underlying price curve, the analyses indicated that the average additional revenue is EUR 7.0 per megawatt hour, resulting in an estimated revenue from dispatchable DERs in the VPP on spot market of EUR 18,000 per megawatt year.

In this model, the spread between highest and lowest prices on a given day has a strong influence on profitability and can vary significantly depending on the share of solar energy and the rate at which transmission infrastructure is built out. Figure 16 shows the price spread for two hypothetical countries on days in January and June.

Figure 16. Spot-market price spread for two hypothetical countries on days in June and January

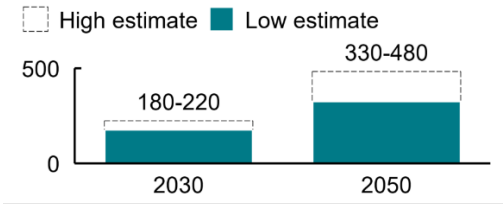


Another point to consider is that larger VPPs have relatively smaller forecast errors, meaning a smaller share of VPP capacity is needed for internal balancing and more is available for spot-market participation.

Overall, while revenues look positive, this assessment is highly uncertain because it's difficult to estimate underlying power prices and revenue estimates are simplified, focusing only on wholesale revenues and ignoring cannibalisation effects within and across business cases.

Based on the total cost of ownership and the projected capacity uptake, the calculation of potential future market size of this business case in the European Union is shown in Figure 17.

Figure 17. Potential EU market size for VPPs for intraday spot market, in mEUR



4.8.3 Technical assessment of VPPs for spot markets

Three technical aspects of the business cases were assessed: flexibility response time to the trigger, or signal, from the TSO or DSO; availability throughout the day and year; and resilience to system instability (towards frequency variation, for example).

Flexibility response time to trigger, or signal, from the TSO or DSO. Most favourable performance was identified for the flexibility response time. The relevant timescale is 15 minutes, because 15-minute contracts are traded on the wholesale intraday spot market[59]. The time delay from central VPP control to distributed generation control is typically less than 5 seconds, depending on the technical equipment and the communication channel, and small, flexible VPP assets such as gas turbines in CHP plants can be ramped up and down in less than 60 seconds, especially as they have only small power ranges.

Availability throughout the day and year. This business case performed moderately well for availability throughout the day and year. Availability is strongly dependent on the VPP setup, and it increases with the number of dispatchable plants within the VPP.

Resilience to system instability. System stability is also quite favourable for this business case, as VPPs are highly effective at balancing intraday variability in generation and demand down to 15-minute intervals. Overall, the analyses suggest few challenges in providing flexibility through the wholesale/spot market; the VPP technology for this business case is already mature and in use.

4.9 Business case: VPPS for balancing reserves

4.9.1 Potential time frame for VPPs for balancing reserves impact

An increased need for flexibility arises from increasing levels of intermittent renewables, particularly for the FRR, which depends significantly on solar and wind forecast errors[60]. The average positive FRR demand is anticipated to increase from approximately 12 gigawatts in 2016 to approximately 30 gigawatts in 2050, even assuming dynamic dimensioning of FRR demand and improved forecasts

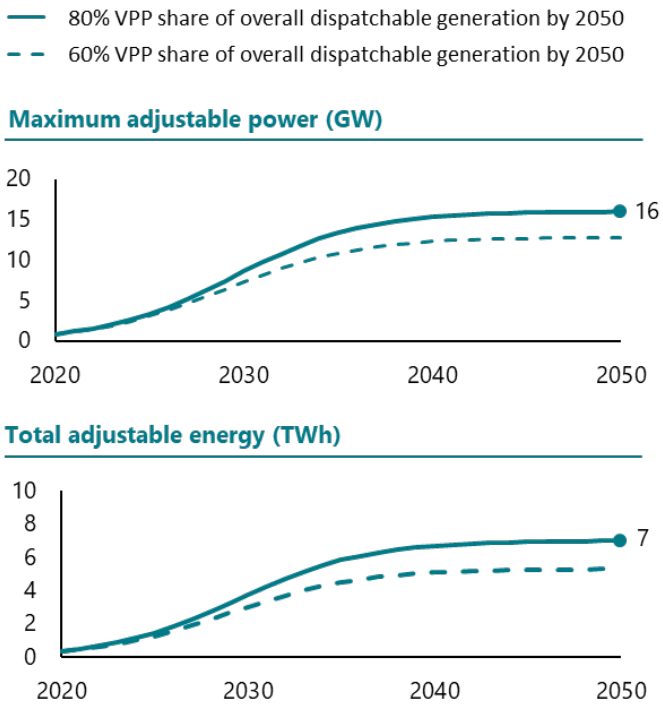
[59] Epex Spot, "15-minute contracts successfully launched on German Intraday market: EPEX SPOT helps to integrate renewable energy into the power system," press release, December 15, 2011, https://www.epexspot.com/en/news/15-minute-contracts-successfully-launched-german-intraday-market.

[60] FCRs are excluded from this business case as they are expected to be provided primarily by batteries and large-scale (reservoir) hydroelectric power.

reflecting methodological advances and shorter delivery times in intraday markets[61]. The same applies for negative FRR. However, through the Manually Activated Reserves Initiative (MARI) platform and the Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation (PICASSO), FRR will be coordinated Europe-wide, which could reduce FRR demand by about two-thirds[62]. Thus, about 20 gigawatts of FRR demand by 2050 is estimated; of that a maximum of 80%, or 16 gigawatts, or a minimum of 60%, or 13 gigawatts, is covered by dispatchable DERs in VPPs, as shown in Figure 18.

To link gigawatts of FRR demand to terawatt hours of FRR energy, calculations use the ratio of 2,688 terawatt hours activated FRR energy and 6,153 gigawatts reserved FRR capacity, which occurred in Germany in 2019[63]. The result is that 437 hours are used.

Figure 18. Impact of flexibility of virtual power plants for balancing reserves on the European energy system



4.9.2 VPPs for balancing reserves revenue

The calculation for this business case is based on an actual FRR reported for Germany from 2016 to 2019[64]. Compared with other Chapters, a higher level of detail is provided in the revenue calculation for VPPs for balancing reserves to provide transparency on the underlying data and assumptions used to calculate revenue from balancing reserve markets (whereas most other business cases generate revenue from wholesale power trading).

[61] Alexander Dreher, Kaspar Knorr, and Diana Böttger, "Common dimensioning of frequency restoration reserve capacities for European load-frequency control blocks: An advanced dynamic probabilistic approach," *Electric Power Systems Research* 170, May 2019, https://www.researchgate.net/publication/331035748_Common_dimensioning_of_frequency_restoration_reserve_capacities_for_European_load-frequency_control_blocks_An_advanced_dynamic_probabilistic_approach.

[62] Ibid.

[63] "Was ist Regelenergie?," Next Kraftwerke, n.d., https://www.next-kraftwerke.de/wissen/regelenergie.

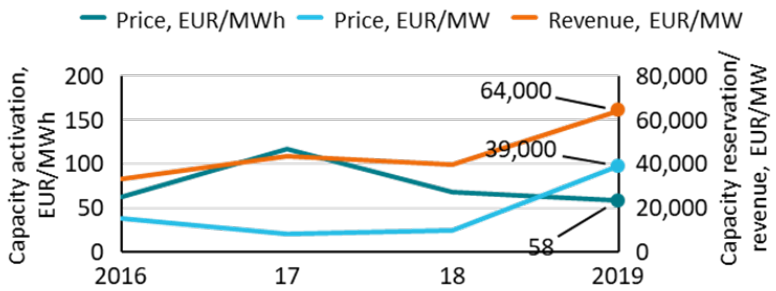
[64] "Was ist Regelenergie?" As no model is available to identify the costs of FRR for 2030, cost data from 2016 to 2019 is used as proxy.

The analysis assumes that the 2016 to 2019 German FRR data is representative of Europe, and it calculates revenue on the German numbers only. The values for 2019 are:

- activated energy (aFRR, mFRR): 2,688 gigawatt hours
- reserved capacity (aFRR, mFRR): 6,128 megawatt hours
- full-load hours: 437
- associated cost (capacity reservation): EUR 239 million
- associated cost (activation): EUR 155 million
- revenue from FRR capacity reservations: EUR 39,000 per megawatt
- revenue from FRR energy delivery: EUR 58 per megawatt hour

Capacity reserve prices in Germany from 2016 to 2019 varied from EUR 6,500 to EUR 39,000 per megawatt, and activation costs ranged from EUR 62 to EUR 116 per megawatt hour. Revenue varied from EUR 33,000 to EUR 64,000 per megawatt (see Figure 19).

Figure 19. Frequency restoration reserve capacity reservation price, activation cost and revenues in Germany from 2016 to 2019



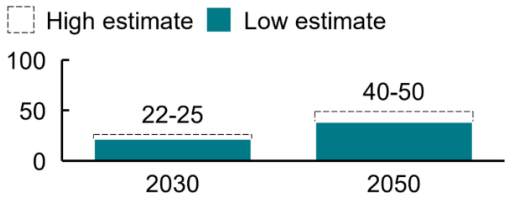
Two other points are worthy of consideration:

Larger VPPs can have larger profit margins because a significant part of their operating expenses can be independent of capacity/generation through, for example, VPP control-centre personnel or optimiser licenses.

Because larger VPPs have relatively smaller forecast errors, a smaller share of VPP capacity is needed for internal balancing and more is available for ancillary services and spot market participation.

Based on the total cost of ownership and the projected capacity uptake, the potential future market size for VPPs for balancing reserves is shown in Figure 20.

Figure 20. Potential EU market size for VPPs for balancing reserves, mEUR



This analysis suggests high challenges in estimating the revenues from balancing reserve markets. While the revenues look positive, this assessment is highly uncertain because it's difficult to estimate underlying power prices and revenue estimates are simplified, focusing only on balancing reserve revenues and ignoring cannibalisation effects within and across business cases. Furthermore, common FRR dimensioning is expected to significantly reduce demand for FRR in coming years.

4.9.3 Technical assessment of VPPs for balancing reserves

Three technical aspects of the business cases were assessed: flexibility response time to the trigger, or signal, from the TSO or DSO; availability throughout the day and year; and resilience to system instability (towards frequency variation, for example).

Dispatchable capacity from VPPs is highly suitable for FRR on the balancing reserve markets.

Flexibility response time to trigger, or signal, from the TSO or DSO. The activation times of the three standard products of balancing reserves – FCR, FRR (both automatic and manual) and replacement reserve (RR) – differ among countries in Europe[65].

FCR: 50% for less than 15 seconds and 100% for less than 30 seconds.

aFRR: Activation time is a minimum of 0 to 10 minutes and a maximum of 5 to 15 minutes.

mFRR: Activation time is a minimum of 5 to 10 minutes and a maximum time of 10 to 15 minutes.

RR: Activation time is a minimum of 15 to 60 minutes and a minimum time of 5 minutes to infinity.

Availability throughout the day and year. Most favourable performance was identified for availability throughout the day and year, because assets designated by markets to provide balancing reserves must be able to deliver at all times. Activations result from frequency deviations (FCR) and unforeseen schedule deviations due to forecast errors, power plant outages or line failures (FRR, RR).

Resilience to system instability. VPPs, especially those for ancillary services, are highly efficient at contributing to system stability.

Overall, the application of VPPs providing balancing reserves, already mature in frontier VPP markets such as Germany, will likely face low challenges. Scale-up across Europe may emerge in line with general VPP uptake.

4.10 Business case: VPPs for internal balancing

4.10.1 Potential time frame for VPPs for internal balancing impact

Internal balancing ensures power-generating companies deliver the power as agreed in day-ahead markets. This is critical, as wind and solar are weather-dependent. Day-ahead forecast errors of variable RES range from less than 1% normalised root-mean-square error (nRMSE) for whole countries to 20% nRMSE for small VPPs[66]. The demand for internal balancing depends strongly on the VPP's power concentration and spatial extension as well as weather conditions.

Three uptake scenarios were formulated, assuming 3%, 4% and 8% nRMSE, respectively, of variable renewable energy VPP generation in 2050. Applying approximately 2 terawatts of variable renewable energy generation from VPPs in 2050, the need for flexibility in these business cases amounts to 60, 80 and 160 gigawatts, respectively. Applying this formula to approximately 4,300

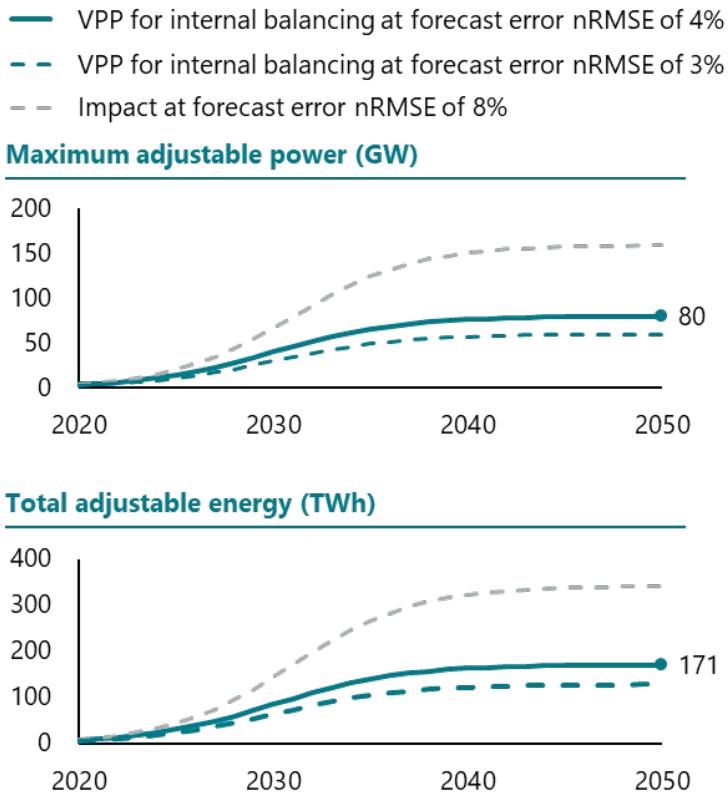
[65] ENTSO-E, AS Survey 2020, Excel workbook, n.d., https://eepublicdownloads.azureedge.net/clean-documents/mc-documents/balancing_ancillary/2021/ENTSO-E_AS_survey_2020_results_final.xlsx; and Commission Regulation (EU) 2017/1485, Establishing a guideline on electricity transmission system operation, August 2, 2017, http://data.europa.eu/eli/reg/2017/1485/oj.

[66] Kaspar Knorr, *Analysis of Forecast Errors of ENTSO-E Transparency Platform*, Research Gate, April 2018, https://www.researchgate.net/publication/324248743_Analysis_of_forecast_errors_of_ENTSO-E_transparency_Platform.

terawatt hours of variable renewable energy generation from VPP by 2050 results in the energy values shown in Figure 21[67].

Widely distributed VPPs and VPPs with a low variable renewable energy share have less need for internal balancing. The growth developments until 2050 were formulated according to the other VPP business cases.

Figure 21. Impact of flexibility of virtual power plants for internal balancing on the European energy system



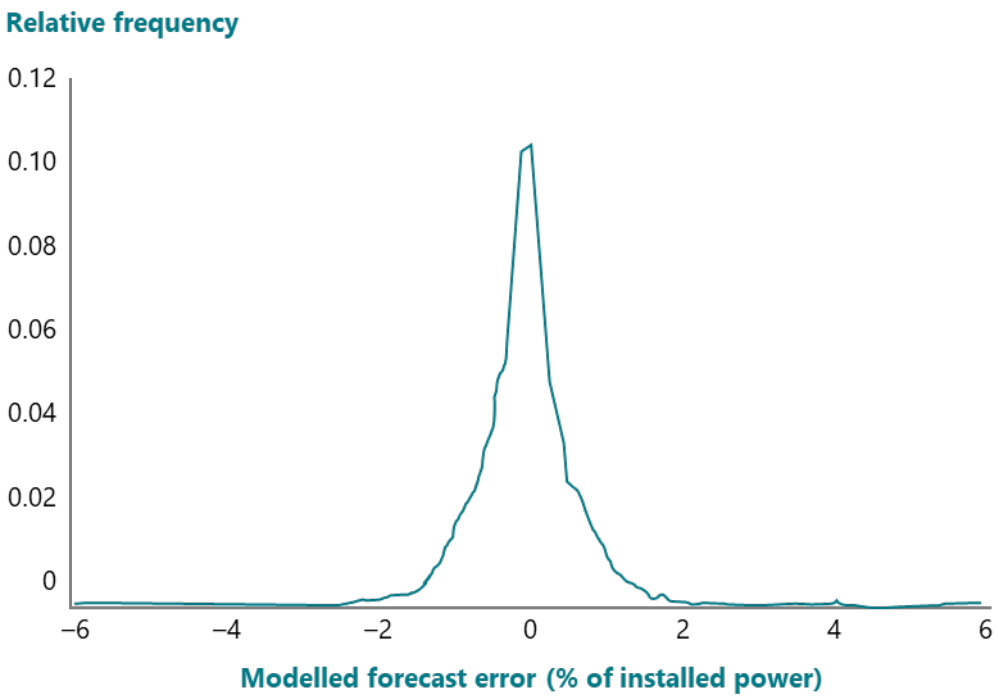
4.10.2 Economic value of VPP internal balancing

Internal balancing is mandatory, because if VPPs are unable to meet their obligations due to unexpected variability of RES (that is, forecasting errors), they have to purchase power at the market price; if they unexpectedly produce too much, they have to sell it at the market price. Due to approximate symmetry of forecasting errors, the capacity sold and the capacity bought are very similar, making this business case a net-zero market at the EU level, as shown in Figure 22.

For these reasons, no revenue estimate is made.

[67] Open energy platforms at https://openenergy-platform.org/dataedit/view/scenario/fh_iee_trafo_fw_wenig_dez_bio_mod_sani_strom_bilanz, https://openenergyplatform.org/dataedit/view/scenario/fh_iee_trafo_fw_wenig_dez_bio_mod_sani_strom_erzeugung and https://openenergy-platform.org/dataedit/view/scenario/fh_iee_trafo_fw_wenig_dez_bio_mod_sani_speicher.

Figure 22. Example forecasting error for a virtual power plant with 8,228 megawatts of wind and 2,977 megawatts of photovoltaic capacity



4.10.3 Technical assessment of VPPs for internal balancing

Three technical aspects of the business cases were assessed: flexibility response time to the trigger, or signal, from the TSO or DSO; availability throughout the day and year; and resilience to system instability (towards frequency variation, for example).

Flexibility response time to trigger, or signal, from the TSO or DSO. This business case performed most favourably in terms of flexibility response time. The relevant timescale is 15 minutes, because internal VPP imbalances must be restored within that time. The time delay from central VPP control to distributed generation control is typically less than 5 seconds, depending on the technical equipment and the communication channel, and small, flexible VPP assets such as gas turbines in CHP plants can be ramped up and down in less than 60 seconds, especially as they have only small power ranges.

Availability throughout the day and year. This business case performed most favourably in terms of availability throughout the day and year. Internal balancing is top priority for VPP operators, as imbalance settlements are costlier than revenue from ancillary services or spot markets. The range of day-ahead forecast errors depends on the VPP's power concentration and spatial extension as well as weather conditions.

Resilience to system instability. This business case supports system stability by ensuring that day-ahead wholesale generation is delivered.

Overall, the analysis indicates low challenges in VPPs for internal balancing. This application is mature in frontier VPP markets like Germany, and scale-up across Europe is expected to emerge in line with general VPP uptake.

5 Business case: Energy sharing communities and peer-to-peer trading

Energy communities include a wide range of activities that are heterogeneous in terms of organisational models and legal forms. They can cover various parts of the value chain, including generation, distribution, storage, supply, consumption and more. Traditionally, community energy activities focused on joint investments in local renewable projects; these energy cooperatives have been in existence since the introduction of government support schemes for renewables and are the most common type of energy community[68].

In terms of grid use, energy communities can be within a geographical location such as a housing complex, they can cross contiguous property boundaries or they can be distributed across non-contiguous boundaries[69].

Residential power consumption makes up a significant share of overall energy and electricity consumption. Peer-to-peer (P2P) trading as well as energy sharing among energy communities could contribute to the European Union's Green Deal and Fit for 55 by trading energy surpluses locally and storing excess energy for later use or trading. The main focus of this business case is the use of stationary batteries by energy communities for energy sharing or P2P trading among prosumers – individual energy consumers who produce all or part of their own demand – community-related producers, and energy-community members who are only energy consumers.

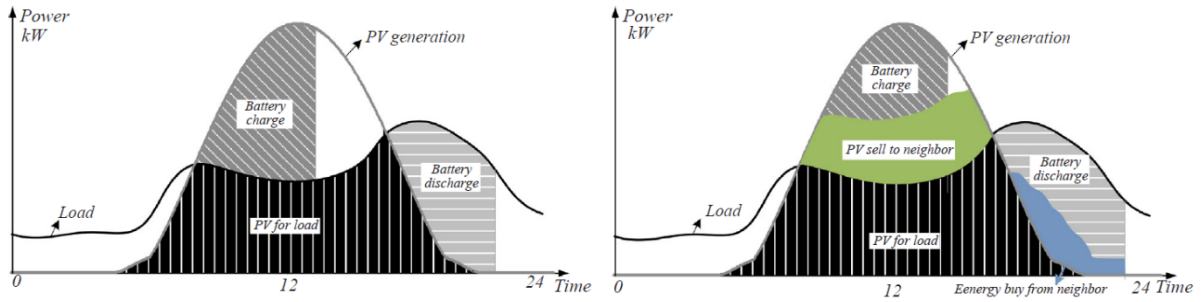
This business case, part of the energy communities use case (as is the business case in Chapter 5, on district heating and cooling), includes energy communities as a whole, which operate under single trade agreements, and P2P trades, which operate under various conditions, due to similarity in their energy flows. It differs from virtual power plants (discussed in Chapter 4) in that batteries are used for flexibility, and flexibility is settled within the community, not in spot or balancing markets. This business case excludes households that do not participate in energy-sharing communities, battery electric vehicles (covered in Chapter 11) and energy trading between small enterprises or public entities.

Figure 23 shows the purpose of sharing energy, in the graph at right, versus using batteries to increase private self-sufficiency, in the graph at left. By trading energy and sharing batteries, the energy community has a larger shaded area under the load curve and thus higher self-sufficiency, so it needs to purchase less energy from outside sources.

[68] European Commission, Directorate-General for Energy, *Digital Technologies and Use Cases in the Energy Sector*; and Elena Caramizaru and Andreas Uihlein, *Energy Communities: An Overview of Energy and Social Innovation,* EUR 30083 EN, European Commission Joint Research Centre (JRC), 2020, https://publications.jrc.ec.europa.eu/repository/handle/JRC119433.

[69] Caramizaru and Uihlein, *Energy Communities*.

Figure 23. Daily charging and discharging behaviour of a battery with photovoltaic generation on a clear day[70]



5.1 Potential time frame for energy sharing communities and peer-to-peer trading impact

The uptake scenario for energy sharing in energy communities is based on a study that describes a possible scenario for 2050[71]. CE Delft, an environmental consultant in the Netherlands, researched the potential for stationary batteries for several types of prosumers, but this business case considers batteries that are explicitly assigned only to energy communities referred to as "collectives"; stationary batteries at households (for private self-consumption), public entities and small enterprises are excluded[72].

The study projects 187 million possible prosumers in Europe by 2050, 42 million of whom are expected to have stationary batteries. We assume 8-kilowatt-hour stationary batteries that fully cycle about 300 times a year (based on a linked PV capacity of 3 kilowatt hours per kilowatt peak)[73]. The study estimates that 45% of prosumers would participate in communities, yielding 19 million stationary batteries by 2050.

The resulting maximum adjustable power would be 46 gigawatts per year, and the total adjustable energy would be 70 terawatt hours per year; the general adoption profile is foreseen to be an S-curve, meaning high growth between 2030 and 2040 followed by flattened growth until 2050.

As this adoption scenario is estimated to be on the high end, a 30% uptake scenario has been introduced as a variation, as shown in Figure 24.

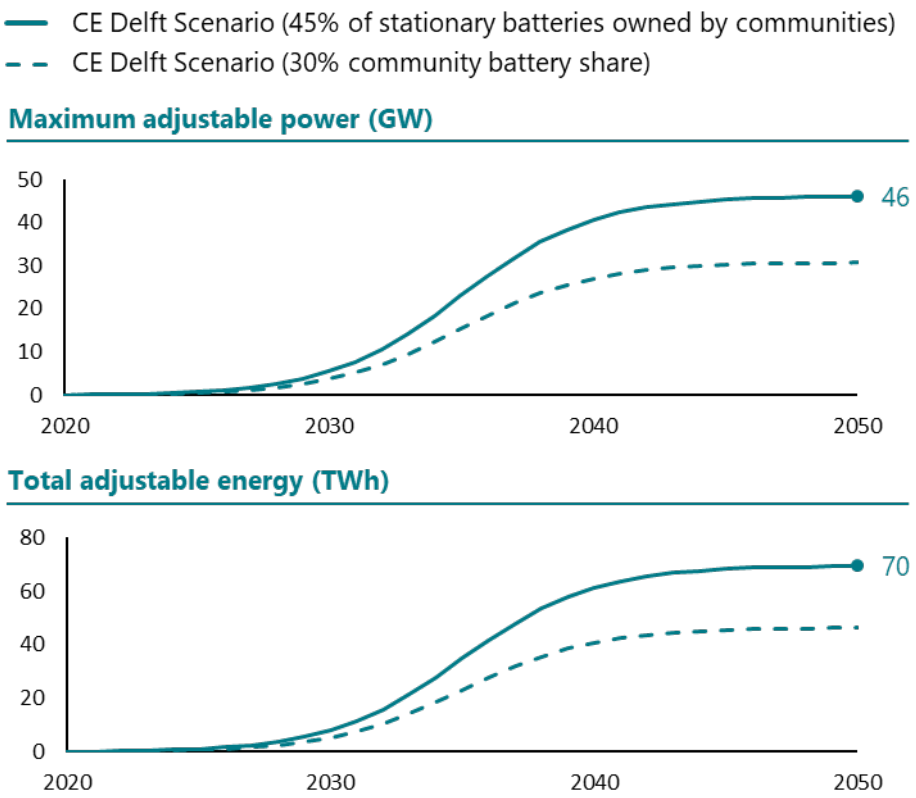
[70] Chao Long et al., "Peer-to-peer energy sharing through a two-stage aggregated battery control in a community microgrid," *Applied Energy* 226, September 15, 2018, https://doi.org/10.1016/j.apenergy.2018.05.097.

[71] Bettina Kampman, Jaco Blommerde, and Maarten Afman, *The Potential of Energy Citizens in the European Union*, CE Delft, September 2016, https://ce.nl/wp-content/uploads/2021/03/CE_Delft_3J00_Potential_energy_citizens_EU_final_1479221398.pdf.

[72] Ibid.

[73] Johannes Weniger et al., *Stromspeicher Inspektion*, University of Applied Sciences, Berlin, 2021, https://pvspeicher.htw-berlin.de/wp-content/uploads/Stromspeicher-Inspektion-2021.pdf; and Jan Figgener et al./RWTH Aachen University, *Wissenschaftliches Mess- und Evaluierungsprogramm Solarstromspeicher 2.0*, Annual Report 2017, 2017, https://doi.org/10.13140/RG.2.2.16917.42727.

Figure 24. Impact of flexibility of energy sharing communities and peer-to-peer trading on the European energy system



The challenges in estimating the adoption of energy communities using stationary batteries and their impact at scale are moderate. Locally derived benefits from community trading seem clear, but overall DSO system benefits (and corresponding upfront costs for large-scale adoption) are less certain. In addition, competition with the use of batteries for TSO/DSO ancillary services can significantly reduce adoption of stationary batteries for the use in energy communities.

5.2 Market overview for energy sharing communities and peer-to-peer trading

Energy communities are still nascent, but the European market for residential, stationary energy storage systems is fairly consolidated, with more than 90% captured by the 10 largest producers, as shown in Table 10). Energy communities participate in the same market.

Market participants are a mix of traditional battery producers (such as Varta and LG Chem), established but younger battery manufacturers (Tesla) and home storage–focused providers (Sonnen, E3 DC and Enphase). About 40% of the European market is served by non-European players[74].

[74] EUPD Research, October 2019.

Table 10. Home battery storage companies by market share

Company	HQ	European market share
Sonnen	Germany	18%
LG Chem	South Korea	16%
BYD	China	14%
E3 DC	Germany	11%
SENEC	Germany	11%
Varta	Germany	9%
Tesla Powerwall	USA	4%
BMZ Group	Germany	3%
Enphase	USA	3%
LG Electronics	South Korea	3%

Based on data gathered by the German market research firm EUPD Research, in 2019 Sonnen had the largest European market share of home-energy storage systems. Sonnen's primary product is the sonnenBatterie, which stores up to 27.5 kilowatt hours of power and invites owners to join, for a fixed monthly fee, the sonnenCommunity to share self-produced energy with other community members. SonnenCommunity members in Germany, Austria, Switzerland and Italy can exchange power without going through a conventional energy provider. Members get a set amount of free energy, depending on the configuration of their system, in exchange for providing Sonnen's virtual power plant with battery capacity[75].

Analyses suggest low challenges in the stationary battery market, as it consists of a mix of established retailers and innovative market entrants. The market is fairly consolidated and includes European and non-European players that increasingly offer EV-related services, power-to-heat integration solutions and other products, in addition to battery hardware.

5.3 Stakeholder mapping for energy sharing communities and peer-to-peer trading

Stakeholders for this business case include society, government, business and the environment.

Society. Energy-community prosumers could benefit financially, as well as through increased social cohesion and increased acceptance and awareness of renewable energy sources[76]. However, they could face uncertain profitability and resistance from nonparticipating neighbours, which could create an energy-participation gap. Actions to mitigate this possibility include increasing neighbourhood buy-in by reducing uncertain profitability through a transparent legal framework with expiry dates for electricity-tax reductions.

Participation in energy sharing and P2P trading requires that citizens be willing to share their battery storage with the community rather than using it privately for self-consumption. Another drawback for society may be that if communities that generate their own electricity don't pay taxes on it, the benefits remain local, meaning the system overall does not benefit from cost efficiency[77].

[75] "What is the sonnenCommunity?," Sonnen, n.d., https://sonnengroup.com/sonnencommunity/.

[76] Caramizaru and Uihlein, *Energy Communities*.

[77] Ibid.

Government. At the government level, the European Union and national governments could consider more people-led energy-related decision-making and accompanying benefits. Municipalities could benefit from energy independence, local investments, local green electricity and heat, and social sustainability, but they may face opposition to renewables if communities don't see the benefits. Options for navigating this opposition include a tax exemption for self-production of electricity, which could include large-scale renewable energy sources. For example, the opportunity to use wind energy for self-consumption without electricity taxes could boost wind energy development if villages could build their own wind turbines on nearby hills, which could increase local acceptance and decrease opposition to centralised power projects. Policymakers may also wish to consider introducing innovative social policies and revisiting regulatory structures "to address the potentially regressive effects that could arise when some societal groups might be impaired by an inability to invest in renewables projects while having to pay the socialised costs of policy support and grid fees," according to a 2020 policy paper by the European Commission's Joint Research Centre (JRC)[78].

Business. Regarding business, local grid operators may benefit from the opportunity to stabilise demand and supply imbalances. Energy sharing and P2P trading within energy communities can be an alternative to grid-capacity expansion, but the technical effort to manage decentralised generators may increase. Equipment suppliers may benefit from an increased demand for stationary batteries and installation of home PV battery systems.

Environment. Energy communities may have an indirect positive impact on land and other environmental resources in the form of reduced emissions. However, the use of resources for the production of batteries, PV systems and ICT infrastructure is an adverse effect.

The key takeaway is that energy communities put citizens at the centre of the energy transition by opening a field of activity for prosumers and active consumers who potentially deliver demand response. It is an approach to the democratisation of the energy system that competes with the centralised energy supply in economic, social, legal and environmental terms.

5.4 Innovation assessment of energy sharing communities and peer-to-peer trading

A qualitative assessment, based on expert interviews and literature review, suggests that Europe's strong innovation in energy communities thus far is a positive sign for future development in this space in the future.

5.4.1 European innovation position of energy sharing communities and peer-to-peer trading

The following aspects were taken into account while assessing innovation in Europe:

- *Market position of European firms*. Europe is a global pioneer in the development of energy communities and their legislative frameworks. Approaches are so heterogeneous that no consistent market for community-energy IT solutions has yet emerged. Energy communities are most likely to be based on cloud platforms, blockchain solutions, P2P trading and RES-origin tracking, which ensures the source is indeed sustainable.
- *Share of European firms in the supplier and customer network*. Because energy communities are new and heterogeneous, many solutions exist, such as small businesses and start-ups for

[78] Ibid.

community IT systems, including Tiko Energy Solutions, Flexens, ieco.io, Engineering DSS, Greenbird Integration Technology, GreenCom Networks and Grid Singularity[79].

- *Level of innovation in European Union.* The high willingness and ability of EU citizens to participate, the supporting EU legislative documents and new digital opportunities make Europe the core innovation centre for energy communities. Example projects include REScoop VPP, a network of 1,900 European energy cooperatives; COME RES, which aims to increase the share of renewables in the electricity sector by supporting target regions in nine European countries; Compile, the leading organisation for community energy development in Croatia and the western Balkans; the OneNet Project, which aims to create a scalable architecture that enables the whole European system to work as one; UP-STAIRS, which is accelerating the creation of energy communities in five pilot regions across the European Union; and SCCALE 203050, which is working to scale the growth of energy communities across Europe[80].

Enabling environments (research institutes, universities, think tanks). Europe is well prepared to establish energy communities because of its many years of practical and legislative experience and its diverse research institutions, including Ghent University's EELAB, the Catholic University of Leuven, the Interuniversity Microelectronics Centre (imec), Hasselt University, and VITO, the Flemish Institute for Technological Research, all in Belgium; the University of Ljubljana, in Slovenia; the Free University of Berlin; Italy's Agency for Energy Efficiency (ENEA); the Center for International Climate Research (Cicero), in Oslo, Norway; and Eindhoven University of Technology, in the Netherlands.

5.4.2 Spillover effects of energy sharing communities and peer-to-peer trading

The following indirect benefits could emerge from innovation in energy sharing communities and peer-to-peer trading:

- *Reusability of infrastructure, data and research results.* The mostly radially connected medium-voltage grids of municipal utilities largely match the area of microgrid-operating energy communities, and blockchain technology may open the possibility of local electricity trading.
- *Transferability to other industries.* The P2P architecture of community energy trading can be adapted to or transferred from other application fields, such as commerce, transportation, hospitality and media.

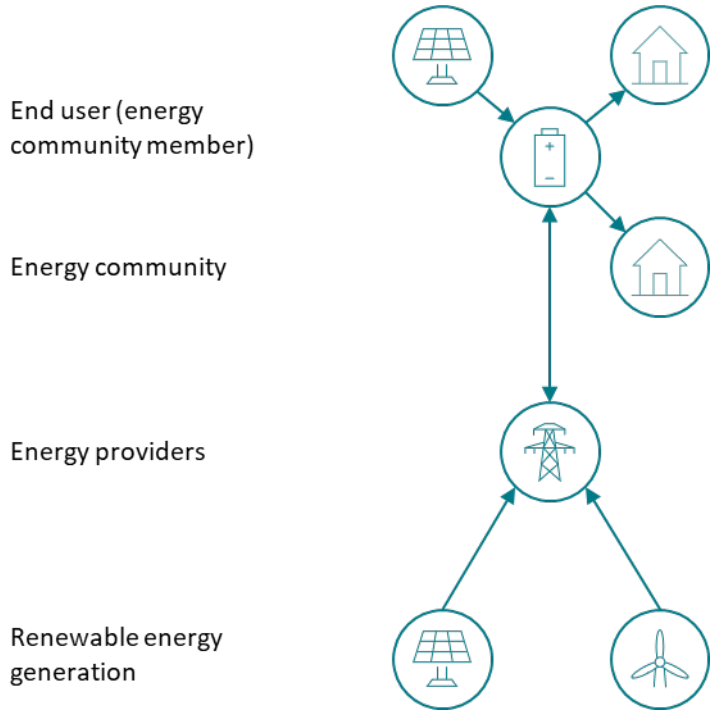
5.5 Economic assessment of energy sharing communities and peer-to-peer trading

This section discusses the main players associated this business case – that is, those expected to primarily implement it – and explores its economic viability for them. Figure 25 shows a schematic of the power and energy flow for this business case as well as the players relevant in each step.

[79] "Digital platform providers," Smart Energy Systems ERA-Net, n.d., https://www.eranet-smartenergysystems.eu/Partners/Digital_Platform_Providers; and Sandra Trittin, "Energy communities as a business model for utilities," *PV Magazine*, February 11, 2020, https://www.pv-magazine.com/2020/02/11/energy-communities-as-a-business-model-for-utilities/.

[80] "REScoop.eu is the European federation of citizen energy cooperatives," Rescoop.eu, n.d., https://www.REScoop.eu; "Advancing renewable energy communities," COME RES, n.d., https://come-res.eu/; "Compile," Compile, n.d., https://www.compile-project.eu/; "What is OneNet?," OneNet, n.d., https://onenet-project.eu/the-project/; and "What is UP-STAIRS?," UP-STAIRS, n.d., https://www.h2020-upstairs.eu/; "You can shape the energy transition," SCCALE 203050, n.d., https://www.sccale203050.eu/.

Figure 25. Power and energy flow for the energy sharing communities and peer-to-peer trading business case



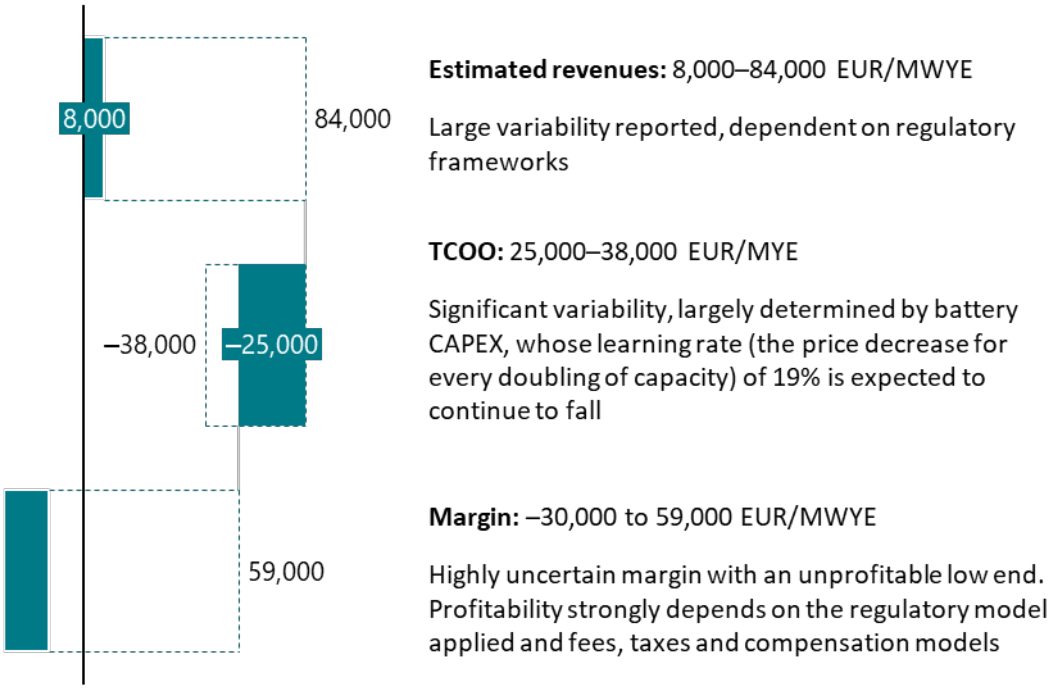
The end user, an energy community member/prosumer, typically generates power through on-site PV panels, stores it in an on-site stationary battery, trades surplus power with community members and offers battery storage capacity to the overall community.

The energy community is a group of community members who participate through power generation, storage or demand-side flexibility. Members share surplus energy virtually, with communities potentially extending beyond the physical scale of microgrids.

Traditional energy suppliers may lose customers to energy communities if the communities' demand, storage and supply is sufficiently robust. Significant community generation and consumption can relieve the burden on TSO grids.

The estimation of revenue and total cost of ownership is shown in Figure 26.

Figure 26 Estimated operating margin of energy sharing communities and peer-to-peer trading[81]



Analysis suggests many likely challenges. The viability of energy communities from a revenue perspective is highly dependent on national regulatory frameworks in terms of taxes and fees. The viability is cost driven by battery CAPEX, and while this cost is falling and expected to continue to do so, overall profitability is highly uncertain; based on US pilot data, profitability may not be possible[82]. The upper limit of the revenue estimate is based on simulations indicating great potential – but that potential is highly dependent on fees, taxes and other effects.

5.6 Energy sharing communities and peer-to-peer trading revenue

Participation in energy communities can reduce prosumer power bills from 3% to 30%, depending on the battery size and C-ratings, also known as the C-rate (how long a battery takes to charge and discharge) of each prosumer in the community[83]. In calculations, the reduction in annual power bills was taken as proxy for revenue from energy trading in energy communities.

Table 11 lists the parameters used in the estimation of revenues.

[81] Jesus Elmer Contreras-Ocaña et al., "Integrated planning of a solar/storage collective," IEEE Transactions on Smart Grid 12, no. 1, August 2020, https://doi.org/10.1109/TSG.2020.3020402; and Long et al., "Peer-to-peer energy sharing through a two-stage aggregated battery control in a community Microgrid."

[82] Claire Curry, "Lithium-ion battery costs and market: Squeezed margins seek technology improvements and new business models," Bloomberg New Energy Finance (BNEF), slides, July 5, 2017, http://data.bloomberglp.com/bnef/sites/14/2017/07/BNEF-Lithium-ion-battery-costs-and-market.pdf.

[83] Contreras-Ocaña et al., "Integrated planning of a solar/storage collective"; and Long et al., "Peer-to-peer energy sharing through a two-stage aggregated battery control in a community Microgrid."

Table 11. Parameters and values used in revenue assessment of energy sharing communities and peer-to-peer trading

Parameter	Value
Prosumers by 2050[84]	187 million
Stationary batteries installed by prosumers by 2050[85]	42 million
Prosumer participation in energy communities[86]	45%
Prosumers with stationary batteries participating in energy communities	19.3 million
Total capacity (8 kilowatt-hour individual battery capacity with C-rate of 0.3)[87]	46 GW
Flexibility hours per year (weighted average of typical annual full-load hours of 900 for solar and 3,000 for wind)	1,500 hours
Total flexible energy per year	70 TWh
Annual household energy bill	EUR 660
Savings range[88]	3%–30%

Based on these parameters and the underlying price curve, estimated revenue ranges between EUR 8,000 and EUR 84,000 per megawatt-year.

In this estimate, the baseline annual power bill of the prosumer is a key driver (in addition to fees and taxes, which determine the P2P benefit over non-P2P trading). This difference is determined by taxes and levies, and varies strongly across Europe, as shown in Figure 27. Such variability has a direct effect on prosumer revenue[89].

[84] Kampman, Blommerde, and Afman, The Potential of Energy Citizens in the European Union.

[85] Ibid.

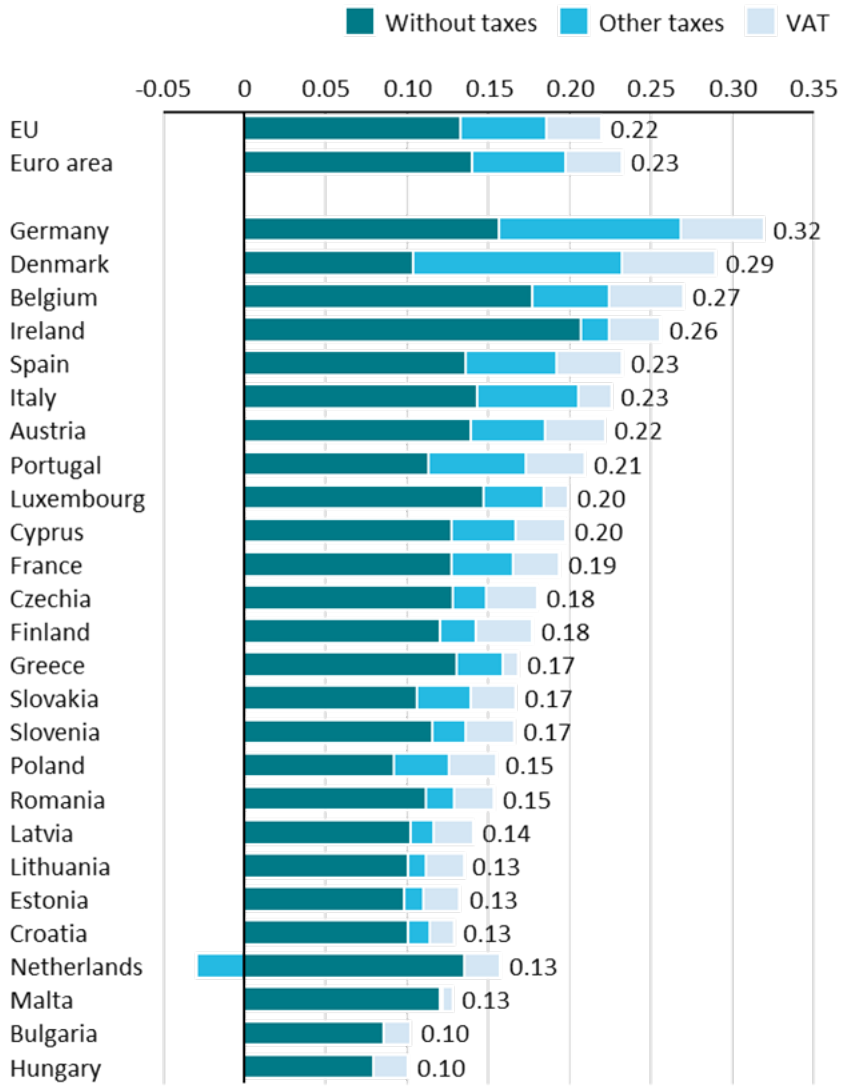
[86] Ibid.

[87] Eurostat/Statistics Explained, "Renewable energy statistics," Eurostat, European Commission, n.d., https://ec.europa.eu/Eurostat.

[88] Contreras-Ocaña et al., "Integrated planning of a solar/storage collective"; and Long et al., "Peer-to-peer energy sharing through a two-stage aggregated battery control in a community microgrid."

[89] Eurostat/Statistics Explained, "Renewable energy statistics," Eurostat, European Commission, n.d., https://ec.europa.eu/Eurostat.

Figure 27. Average retail electricity prices for EU households in the first half of 2021, in euros per kilowatt hour[90]



Other points to consider include:

- Energy communities provide an opportunity for prosumers to reduce energy cost and possibly generate revenues from selling surplus power.
- Energy community margins are expected to increase with community size due to decreased simultaneity of both demand and generation.
- Energy communities can significantly reduce distribution costs by reducing loads to high-voltage grids. A 2020 paper published by the Institute of Electrical and Electronics Engineers shows a German-Dutch cross-border connection between two DSOs at medium voltage level saving more than 30% of its annual costs by doing this[91].

[90] Ibid.

[91] Andreas Stroink, Tim Wawer, and Johann L. Hurink, "Cross-border energy communities on a distribution grid level," Institute of Electrical and Electronics Engineers, in *17th International Conference on the European Energy Market (EEM)*, October 13, 2020, 1–5, https://doi.org/10.1109/EEM49802.2020.9221917.

Estimating revenues from energy-community trading is challenging. Consumer power prices vary widely across Europe, as do taxes and levies that affect the margin between peer-to-grid trading (P2G), peer-to-peer trading (P2P) and traditional energy surplus selling of prosumers. Financial benefits to the prosumer from P2P over P2G are only sparsely reported and are taken from a small 2021 pilot in France and microgrid simulations published in the journal *Applied Energy* in 2018[92]. While the revenue looks positive, this assessment is highly uncertain because it's difficult to estimate underlying power prices and because revenue estimates are simplified, ignoring cannibalisation effects within and across business cases.

5.7 Total cost of ownership for energy sharing communities and peer-to-peer trading

In order to calculate the costs of stationary batteries, it is assumed an equipment lifetime of 20 years, a battery C-rate of 0.3 megawatts per megawatt hour, and 1,500 full-load hours per year. The full-load hours are derived from a combination of solar and wind providing power between 800 and 3,000 full-load hours per year.

To calculate the CAPEX, the following battery composition is assumed: lithium iron phosphate 34%, lithium nickel manganese cobalt oxide 31% and lithium nickel cobalt aluminium oxide 25% as main lithium-ion material combinations[93]. Using the costs for battery installation in 2030 as a basis results in costs of EUR 150 per kilowatt hour[94]. Using 100,000 to 150,000 euros per megawatt hour results in 333,000 to 500,000 euros per megawatt. Other hardware could include gateway installation on site, but limited data is available on the cost.

Fixed operating costs equal 1.5% of original CAPEX costs and range between EUR 5,000 and EUR 7,500 per megawatt[95]. Forecasting and other overhead costs are estimated to be negligible once the DSO connection is established due to a high level of automation. Alternatively, if forecasting is performed within the community, aggregation of data from home-energy management systems can be used instead of external tools.

Total cost of ownership would be EUR 25,000 to EUR 38,000 per megawatt hour per year, as shown in Figure 28.

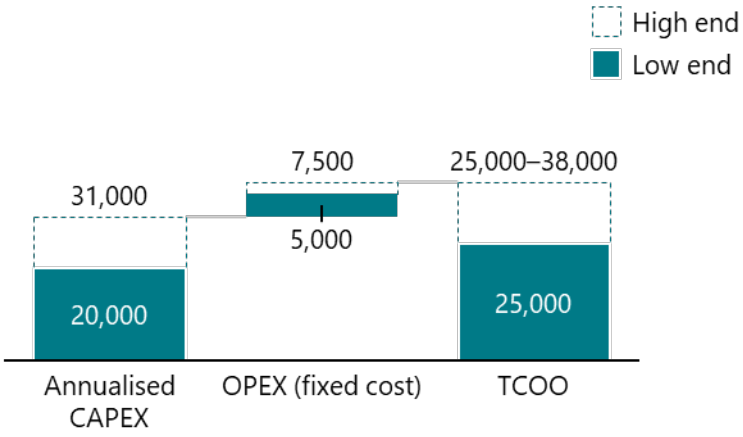
[92] Contreras-Ocaña et al., "Integrated planning of a solar/storage collective"; and Long et al., "Peer-to-peer energy sharing through a two-stage aggregated battery control in a community Microgrid."

[93] David Roberts, "The many varieties of lithium-ion batteries battling for market share," Canary Media, April 21, 2021, https://www.canarymedia.com/articles/the-many-varieties-of-lithium-ion-batteries-battling-for-market-share/.

[94] International Renewable Energy Agency (IRENA), *Electricity Storage and Renewables: Costs and Markets to 2030*, October 2017, https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Oct/IRENA_Electricity_Storage_Costs_2017.pdf.

[95] IRENA, *Electricity Storage Valuation Framework: Assessing System Value and Ensuring Project Viability,* March 2020, https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Mar/IRENA_storage_valuation_2020.pdf.

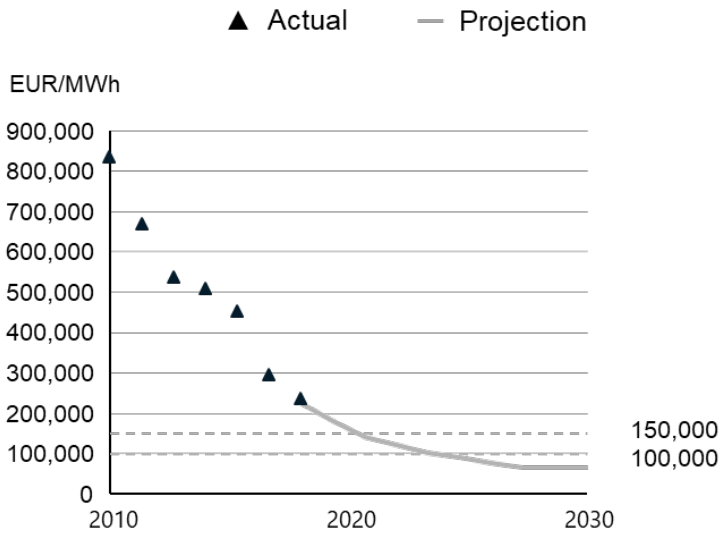
Figure 28. Total cost of ownership for energy sharing communities and peer-to-peer trading, in euros per megawatt-year



Two additional points to consider:

- Intense price competition is leading battery manufacturers to develop new chemistries and improved processes to reduce production costs. The learning rate, or price decrease for every doubling of capacity, is 19%, which will bring down the current (2021) price of around EUR 150 per kilowatt hour.
- The cost of flexibility of energy sharing in energy communities is closely linked to the cost of batteries in general, with lithium-ion technology dominating. Battery prices are expected to continue to fall, making flexibility from batteries increasingly attractive.

Figure 29. Learning rate of lithium-ion batteries[96]



Estimating TCOO is moderately challenging, as the competitiveness of batteries is uncertain, stemming from competition in the ancillary-services space and from using electric vehicles to store power for use in the home during outages. At sufficiently low cost, home energy storages could

[96] Based on Curry, "Lithium-ion battery costs and market."

become a widespread avenue for flexibility due to the potential for electricity-cost savings and additional revenues.

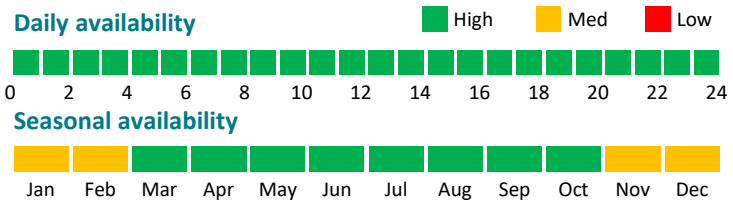
5.8 Technical assessment of energy sharing communities and peer-to-peer trading

Three technical aspects of the business cases were assessed: flexibility response time to the trigger, or signal, from the TSO or DSO; availability throughout the day and year; and resilience to system instability (towards frequency variation, for example).

Flexibility response time to trigger, or signal, from the TSO or DSO. The flexibility response time of batteries is most favourable; they can respond instantaneously to community or DSO triggers. Various types of batteries require specific charging regimes or battery management systems. A high C-rate indicates high power can be charged and discharged in a short time, which can be desirable from an intraday flexibility perspective. Today's C-rates for home-energy storages range between 1.0 and 0.3.

Availability throughout the day and year. The performance of batteries was moderately favourable, as shown in Figure 30. Batteries are normally used intraday, with availability limited by their capacity. The design of each energy community determines whether flexibilities are fully available to the energy community or prioritised for the owning household.

Figure 30. Availability of flexibility from energy sharing communities and peer-to-peer trading throughout the day and year



Resilience to system instability. This business case assessed well in terms of system stability, with a most favourable intra- and interday performance due to high ramp rates and availability. Batteries are only moderately suited for congestion management. They are acceptable as the main business case for communities and require local interaction with DSOs in real time, in contrast to location-independent, virtual trading of energy communities. Regarding frequency stabilisation, batteries have a most favourable performance. They are highly suitable for frequency containment reserves (FCRs), which are how they are used by sonnenCommunity.

Overall, home energy storages can change their charging and discharging power within milliseconds, which makes them suitable for intraday power balancing in households and for trading household surplus in energy communities. In addition, communities could trade surplus for FCR or faster applications, such as fast frequency response or synthetic inertia.

The challenges of technical assessment appear to be low. Batteries outperform other energy technologies in terms of performance relevant for power flexibility assessed in this report. Improvements are expected regarding durability, degradation rate, energy density, cost and efficiency.

5.9 Technical infrastructure required for energy sharing communities and peer-to-peer trading

The technical infrastructure of energy communities can be divided into three categories: analog, digital and analytics.

Analog. From an analog perspective, home energy storage systems have to be physically integrated into the grid.

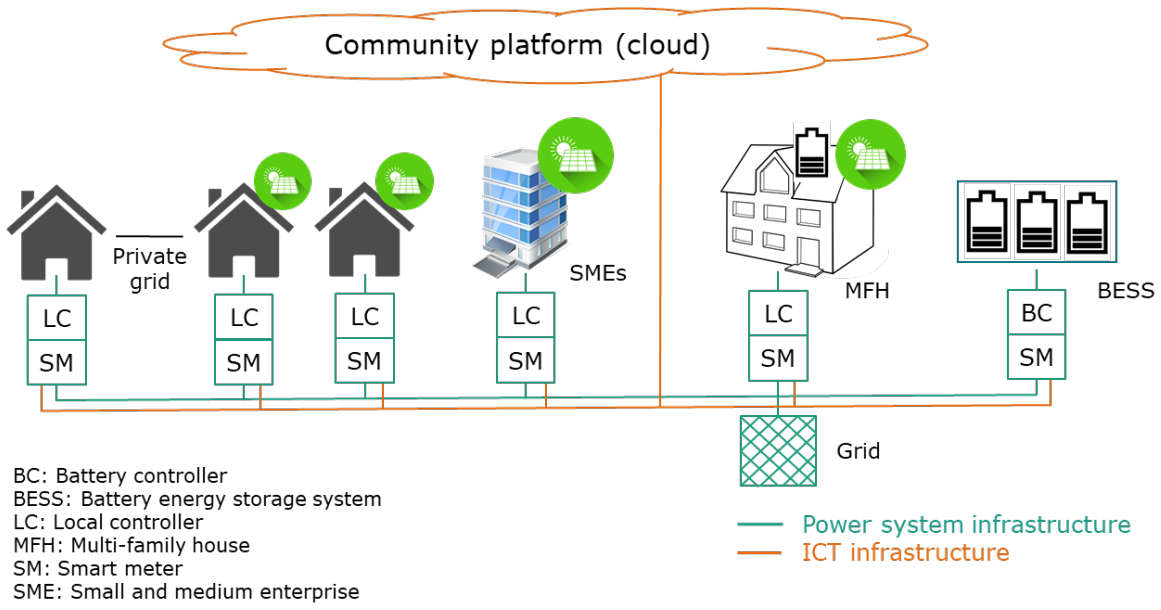
Digital. On a digital level, because user-interfacing products are employed to monitor battery performance, overall power flow and interactions with the community, secure ICT systems must ensure customer data security and prevent cyberattacks. Advanced metering infrastructure simplifies the construction of energy communities. When an energy community operates its own local grid, it needs appropriate grid operation hardware and software solutions.

Analytics. In analytics, trading systems are used for integration to the community's internal market and to external energy markets.

As shown in Figure 31, stationary batteries for energy communities are typically installed on-site (in houses), though external battery energy storage systems are also an option.

Analysis shows likely moderate challenges for technical infrastructure, predominantly regarding the integration of secure advanced metering infrastructure.

Figure 31. Components and ICT infrastructure of energy communities[97]



5.10 Energy sharing communities and peer-to-peer trading risk considerations

Potential risks could be experienced in relation to regulation, cybersecurity, public and user acceptance, and gamification potential.

[97] Based on Figure 1, page 6, in Nicoló Rossetto, ed., *Design the Electricity Market(s) of the Future: Proceedings from the Eurelectric-Florence School of Regulation Conference*, Brussels, European University Institute, June 2017, https://op.europa.eu/en/publication-detail/-/publication/5c9f32ee-590f-11ea-8b81-01aa75ed71a1.

Regulatory. The allocation of benefits from energy communities is highly dependent on regulation, taxes and fees. Regulations may directly affect the profitability of the business case. The concept of energy sharing leverages lower taxes and fees, which can create advantages for participants but potentially places a greater burden on nonparticipants to pay societal costs for other elements (like network fees). Energy communities may strive to operate without traditional energy providers, as, for example, sonnenCommunity does; this results in reduced income for regulated DSOs.

Cybersecurity. Because they rely on the digital control of a large number of distributed assets, energy-sharing systems are vulnerable to cyberattacks. Small-scale disruptions could also destabilise adjacent and overlying grid areas.

Public and user acceptance. The allocation of benefits from energy communities could affect public perception and the acceptance of energy communities. The concept of energy sharing is essentially based on lower taxes and fees, which can create an advantage for participants and a relative disadvantage for households that do not participate due, for example, to prohibitive upfront costs.

Gamification potential. If energy is not traded transparently, power and cost optimisation for households could be used to act against the community system for individual financial gain. A similar principle has been observed at scale in balancing responsible parties, or companies responsible for maintaining supply and demand on the energy market, where a last-minute import from abroad was required due to a significant negative deviation from the balance in Germany's power market in June 2019[98].

It is possible players will experience moderate challenges in addressing the risks of energy communities. High technical risks like cybersecurity can be resolved using available technology, but more significant effort may be required to consider regulations and taxes and fee structures for energy communities to function well at scale.

[98] *Investigation on System Imbalances in Germany in June 2019*, allemagneenergiesdotcom, November 2019, https://allemagneenergiesdotcom.files.wordpress.com/2019/07/study-balancing-state-june-2019.pdf.

6 Business case: District heating and cooling

Heating demand makes up a significant share of overall energy consumption. District heating and cooling (DHC) networks, also referred as heat networks, are centralised solutions for meeting heating and cooling demand. DHC networks could contribute to Fit for 55 and the Green Deal in two ways: They decarbonise by electrifying heat generation through the addition of renewable low-carbon sources such as heat pumps and electric boilers, and they provide flexibility to balance the power grid by decoupling heat demand and power load.

This business case, which falls under the use case for energy communities, focuses on flexibility provided by two means:

- Through significant electrification of heat generation using heat pumps, boilers or a combination of the two coupled with heat storage capacity, which enables the decoupling of heat demand and power load
- Through combined heat and power plants (CHP) – using fossil or non-fossil fuels – for ancillary services and power generation

This business case assumes that all DHC grids that provide flexibility to the power grid will be at least 4th generation, with low heating temperatures and high insulation standards, although electrification of heat generation and the possibility of providing flexibility to the grid can also be retrofitted into traditional high-temperature, centralised district heating networks.

Direct solar heating, industrial-waste heat and other decentralised sources are excluded from this business case.

6.1 Potential time frame for district heating and cooling impact

Two scenarios are used to assess the growth of DHC capacity, both based on Heat Roadmap Europe, funded by the EU Horizon 2020 research and innovation programme[99]:

In the conventionally decarbonised scenario, which encourages renewables but does not radically change the heating and cooling sector, the estimated maximum adjustable power is 85 gigawatts. Nearly all of that (98%) is provided by CHP plants, with the remainder provided by heat pumps and geothermal solutions.

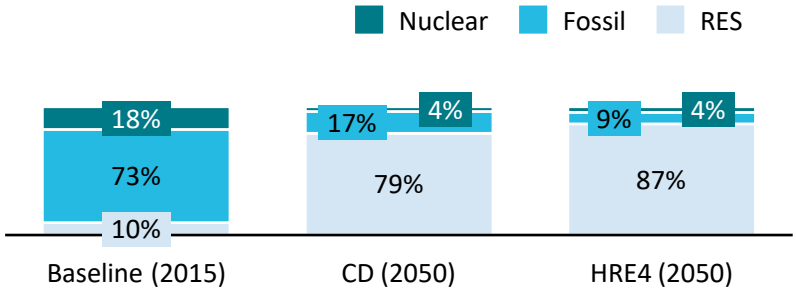
The second scenario also represents a decarbonised energy system, but with a redesigned heating and cooling sector that includes the addition of new renewable energy sources such as excess heat from industry or large heat pumps.

Figure 32 shows the power generation mix of the two scenarios[100]. While the second scenario has twice as much generation capacity (in gigawatts) as the conventionally decarbonised scenario, utilisation is lower. This results in an only slightly higher total adjustable energy (in terawatt hours).

[99] Susana Paardekooper et al., *Heat Roadmap Europe 4 – Quantifying the Impact of Low-Carbon Heating and Cooling Roadmaps*, project 695989, Aalborg University, 2018, https://vbn.aau.dk/ws/portalfiles/portal/288075507/Heat_Roadmap_Europe_4_Quantifying_the_Impact_of_Low_Carbon_Heating_and_Cooling_Roadmaps.pdf.

[100] Ibid.

Figure 32. Results from power-generation modelling for a 2015 baseline and the 2050 conventionally decarbonised (CD) and RE4 scenarios for district heating and cooling



In addition to scenarios for district heating and cooling capacity growth, two scenarios assess the uptake of flexibility in DHC networks: In the first scenario, 50% of installations will be providing flexibility by 2050; in the second, 100% will.

A reason for the significant difference in possible adoption is that decoupling heat demand and supply requires well-insulated grids, which traditional high-temperature district heating networks typically do not have. With numerous traditional, high-temperature grids still in operation, effective adoption may range widely.

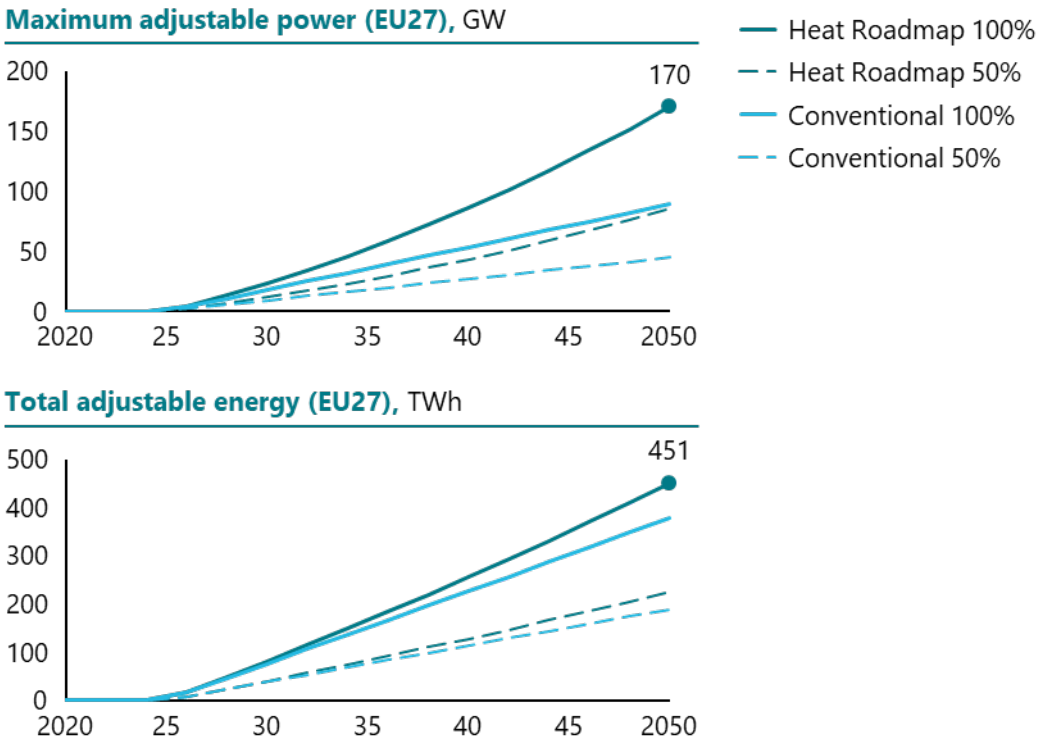
Newer, 4th generation DHC networks with low-temperature heating are more suitable for providing power-flexibility services because they have better insulation and are therefore better suited for electric heating. In addition, standardisation of regulations (flexibility design requirements, rate-case regulation and compensation structure) will likely influence the adoption by 2030 and beyond.

These four scenarios (two for each of the two HRE scenarios) are shown in Figure 33 The total maximum adjustable power is estimated at 170 gigawatts peak capacity (80% CHP, 15% heat pumps, 3% geothermal, and 2% electric boilers).

Based on the share of residential heat and cooling demand, the six countries with the largest potential for this use case are Germany, France, Italy, Poland, the Netherlands and Spain[101].

[101] Urban Persson and Sven Werner, *Quantifying the Heating and Cooling Demand in Europe*, Stategro Project/EU Intelligent Energy Europe Programme, 2015, https://heatroadmap.eu/wp-content/uploads/2018/09/STRATEGO-WP2-Background-Report-4-Heat-Cold-Demands.pdf.

Figure 33. Impact of flexibility of district heating and cooling on the European energy system[102]



6.2 Market overview for district heating and cooling

The European DHC market is mature and low-growth, with established utilities like Vattenfall and Engie as well as local DHC operators such as Helen and Wien Energie.

Overall, the European DHC market is highly localised and fragmented, with market shares of even the larger companies below 5%. Specialist solution providers are starting to move into the market, mostly through partnerships with traditional DHC operators exploring innovative topics such as the integration of RES and the monetisation of flexibility in ancillary services and capacity markets.

Market entrants like Sympower, a demand-response specialist, provide services to new or existing DHC grids and could also create new revenue streams beyond those from heating and cooling.

Vattenfall and Sympower collaborated on two projects totalling 60 megawatts of firm frequency response (FFR) reserves and covering most of Sweden's FFR capacity: Arctic Paper, a fossil-free paper and packaging manufacturer, and Vattenfall Uppsala Heat, a local supplier of district heating, cooling and steam in the city of Uppsala that uses household and industrial waste as fuel for the CHP plant.

[102] International Energy Agency (IEA), "Installed capacity in the European Union, 2000–2010, and projections up to 2040 in the stated policies scenario," n.d., https://www.iea.org/data-and-statistics/charts/installed-capacity-in-the-european-union-2000-2010-and-projections-up-to-2040-in-the-stated-policies-scenario.

Table 12. District heating and cooling operators by heat sales

	Company	Headquarters	Heat sales from DHC (TWh)	European market share (%)
European DHC operators	Vattenfall	Sweden	17.1	2.9%
	Engie	France	14.1	2.4%
	PGNiG Termika	Poland	11.3	1.9%
	Fortum	Finland	10.8	1.8%
	PGE Energia Ciepla	Poland	9.62	1.6%
	Stockholm Exergi	Sweden	8.50	1.4%
	Helen	Finland	6.60	1.1%
	Wien Energie	Austria	5.96	1.0%
	MVV Energie	Germany	5.60	0.9%
Non-EU DHC operators for reference	Korea District Heating Corp.	South Korea	16.5	n/a
	Beijing District Heating Group	China	10.7	n/a
	GS Energy	South Korea	4.21	n/a

Table 13. A deeper dive on some district heating and cooling operators

Company	Description	Projects
Vattenfall Sweden **Sympower France**	Sympower and Vattenfall collaborated to develop a solution for allowing Uppsala's CHP heating plant to trade FFR capacity in the local market	See detail above
PGNiG Termika Poland	PGNiG provides heat for one of the largest district heating systems in the European Union (it does not include cooling), using a system of plants deployed at various temperatures	Plans to switch plants from coal to gas or biofuel, allowing for higher flexibility
Fortum Finland	As part of its artificial intelligence optimisation solution, Fortum offers DSR for district heating to avoid the need for backup heat plants.	Collaborating with the city of Espoo to give it carbon-neutral district heating by 2030

Analysis suggests few challenges in the DHC market, as it consists of a mix of established energy utilities and established energy retailers. Several of these players have started exploring flexibility options and are collaborating with specialised companies that offer symbiotic services and products.

6.3 Stakeholder mapping for district heating and cooling

Stakeholders for this business case include society, governments and energy-industry businesses, including DHC operators.

Society. For society, 4th generation and beyond DHC could increase the participation of prosumers as a result of enhanced flexibility and ease of participation. The addition of hot-water storage will require minor additional land use near residential areas.

Governments. Municipalities are a key DHC stakeholder. Because they profit from local value creation and urban planning, building authority and environmental departments influence the DHC solutions adopted[103]. For national governments and European policymakers, the adoption of flexible, low-carbon DHC networks can contribute to decarbonisation goals. National governments and European policymakers can directly affect profitability of new revenue streams for DHC operators and as such can stimulate the adoption of DHC grids in the pursuit of decarbonisation goals[104].

Energy-industry businesses. On the one hand, this business case represents an opportunity for DHC operators to integrate RES at scale and thereby decarbonise operations while adding a new revenue stream through the power price spread[105]. On the other hand, it adds complexity to the operation of the plant and increases cybersecurity risks because automation is increased, and a connection must be made to the external triggering mechanism. In addition, a larger hot-water storage tank may be needed for decoupling heat demand from power load. Flexibility should enhance the business case for operators and should be a natural consideration for all new networks. To ensure that flexibility becomes the norm for new DHC networks, data transparency is helpful for assessing potential business cases, incentives and regulation changes.

In addition to DHC operators, engineering firms and equipment suppliers will likely see an impact from this business case since the need for more storage and information and computer technology equipment would result in increased demand for their services.

Overall, stakeholders – particularly government and DHC operators – will likely encounter positive developments from this business case, so few challenges to it are likely from the stakeholder perspective.

6.4 Innovation assessment of district heating and cooling

A qualitative assessment, based on expert interviews and literature review, indicates that overall, innovation based on European resources and knowledge should encounter few challenges. The European Union has significant energy research capabilities at universities and research institutes, and European firms often participate in or lead DHC projects from inception to operation.

6.4.1 European innovation position of district heating and cooling

The following aspects were taken into account while assessing innovation in Europe:

- *Market position of European firms*. Virtually all operators in the EU DHC market are European companies, largely due to local ownership of city and regional DHCs.
- *Share of European firms in the supplier and customer network*. European firms lead or participate in DHC projects from inception to operation. Examples include Uniper, E.ON, Statkraft and Engie

[103] Marina Galindo Fernández et al., Efficient District Heating and Cooling Systems in the EU – Case Studies Analysis, Replicable Key Success Factors and Potential Policy Implications, EUR 28418 EN, Joint Research Centre/European Commission, December 2016, https://publications.jrc.ec.europa.eu/repository/handle/JRC104437.

[104] Marina Galindo Fernández et al., Integrating Renewable and Waste Heat and Cold Sources into District Heating and Cooling Systems, Joint Research Centre/European Commission, February 2021, https://op.europa.eu/en/publication-detail/-/publication/cc9516dc-7268-11eb-9ac9-01aa75ed71a1/language-en.

[105] Persson and Werner, Quantifying the Heating and Cooling Demand in Europe.

for generation; Ramboll and Dall Energy for engineering and construction; and ABB, Engie, Veolia and Danfoss for heat control systems[106].

- *Level of innovation in the European Union.* There's a strong link between European universities and pilot projects in DHC networks. Initiatives include Solar District Heating and KeepWarm, both of which are funded by the European Commission's Horizon 2020 programme; InnovationCity Ruhr, in Bottrop, Germany; the city of Kajaani in Finland; and Mijnwater in the municipality of Heerlen, Netherlands[107].
- *Enabling environments (research institutes, universities, think tanks).* Europe is strongly positioned, with independent energy-system research laboratories such as Fraunhofer IEE and Fraunhofer ISI in Karlsruhe, Germany; the Netherlands Organisation for Applied Scientific Research (TNO) in the Hague; and VITO, the Flemish Institute for Technological Research, in Belgium, supplementing the fundamental research being undertaken at universities including Aalborg University, Utrecht University, Halmstad University and the University of Flensburg[108].

6.4.2 Spillover effects of district heating and cooling

The following indirect benefits could emerge from innovation in district heating and cooling:

Reusability of infrastructure, data and research results. Reusability of dedicated flexibility infrastructure, or storage volume, is low, while reusability of research on predictive control systems and materials and construction innovation is high.

Transferability to other industries. The industrial integration of heat processes is mature, but integration of RES and flexibility through buffering, or thermal water storage to reduce cycling of the heat source, remains a growth market. Analysis suggests few challenges in accessing the right types innovation with Europe-local resources and knowledge, based on significant energy research programmes at universities and institutes.

6.5 Economic assessment of district heating and cooling

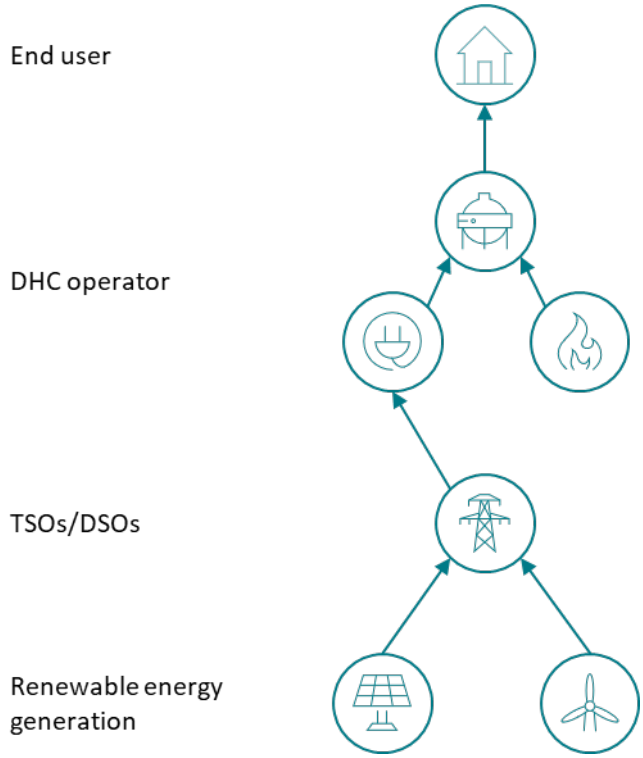
This section discusses the main players associated with the DHC business case – that is, those expected to primarily implement it – and explores its economic viability to them. Figure 34 shows a schematic of the power and energy flow for this business case as well as the relevant players in each step.

[106] District Heating Market by Heat Source (Coal, Natural Gas, Renewable, Oil & Petroleum Products), Plant Type (Boiler Plant, CHP), Application (Residential, Commercial, Industrial), and Geography: Global Forecast to 2023, MarketsandMarkets, November 2018, https://www.rnrmarketresearch.com/district-heating-market-by-heat-source-coal-natural-gas-renewable-oil-petroleum-products-plant-type-boiler-plant-chp-application-residential-commercial-industrial-and-geography-global-forecast-to-2023-market-report.html; Ankit Gupta and Aitya Singh Bais, District Heating Market Size by Source, by Application (Residential, Commercial [College/University, Office, Government/Military], Industrial [Chemical, Refinery, Paper]), Industry Analysis Report, Regional Outlook, Covid-19 Impact Analysis, Price Trends, Competitive Market Share & Forecast, 2020–2026, GMI1401, Global Market Insights, December 2020, https://www.gminsights.com/industry-analysis/district-heating-market; and Fortune Business Insights, District Heating Market Size, Share & Industry Analysis, by Heat Source, by Plant Type, by Application (Residential, Commercial, Industrial), and Regional Forecast, 2020–2027, Market Research Report, September 2020, https://www.fortunebusinessinsights.com/industry-reports/district-heating-market-100097.

[107] Gupta and Bais, *District Heating Market Size by Source*; and Fortune Business Insights, *District Heating Market*.

[108] Paardekooper et al., *Heat Roadmap Europe 4*; and Euroheat & Power, https://www.euroheat.org.

Figure 34. Power and energy flow for the district heating and cooling business case



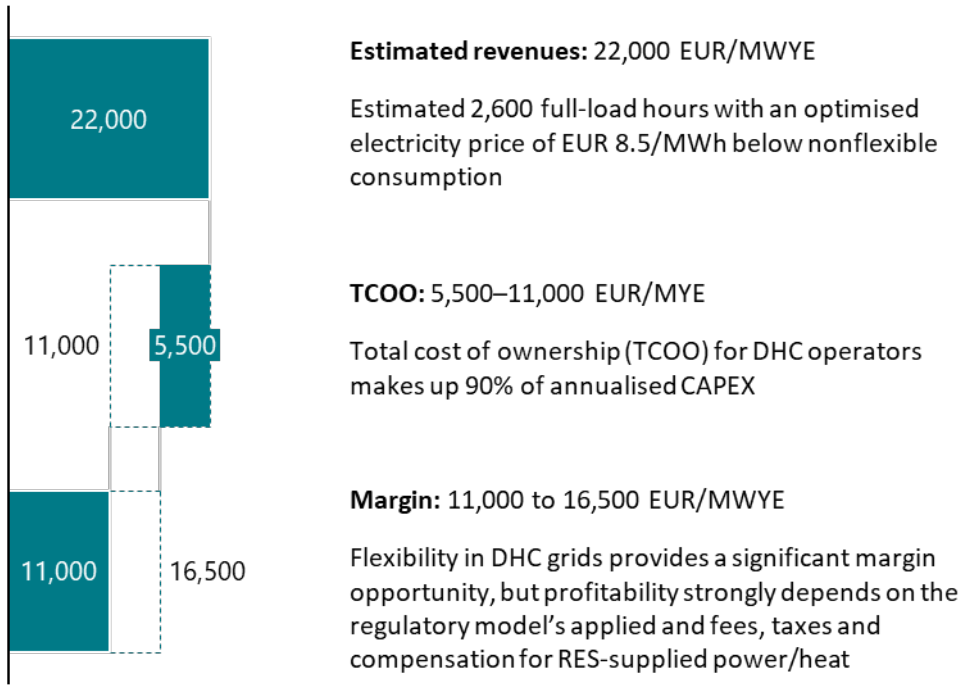
In this business case, the key players are the DHC operators and the TSOs and DSOs.

The DHC operator can generate a new revenue stream from intraday electricity price fluctuations and ancillary services. This can take three forms: (1) the shift in demand for electricity (in the case of electrified DHC networks), (2) the shift in supply of electricity (in the case of combined heat and power), and (3) the provision of ancillary services. Figure 35 shows the estimated margin from monetising flexibility based on intraday price fluctuations. The overall viability and profitability strongly depend on the dimensions of the system, including buffer volume, electrified heating capacity, level of thermal insulation and so forth, and the price spread and consumption profiles.

If DHC flexibility is used for ancillary services or congestion mitigation, the TSO/DSO profits, and it is therefore expected to pay for the availability of flexibility. End users should not notice differences in the comfort level or reliability of their heating, but they may expect lower consumption bills as a consequence of the extra revenue streams tapped by their DHC operator.

Analysis suggests few challenges for DHC operators in successfully monetising the power price spread due to a considerable projected margin, though fees, taxes and other additional expenses might reduce this significantly.

Figure 35. Revenue and total cost of ownership, EUR/MWYE



6.5.1 District heating and cooling revenue

Revenue for this business case is approximated based on the 2030 European average hourly price curve, which is derived from a model considering wholesale-based hourly electricity demand and supply from a power mix including conventional and renewable energy sources as well as batteries. Only transmission (and therefore congestion) between countries is considered.

The maximum interval length during which a certain number of hours of electricity for heating needs to be consumed is defined based on the storage duration and full-load hours. With these parameters set, the interval length is six hours, considering that a duration of no consumption at the end of one interval adds onto a duration of no consumption at the beginning of the next interval, and in sum may not be more than 8.5 hours. During each interval, 1.8 hours need to be consumed, and those hours with the lowest price are chosen for consumption.

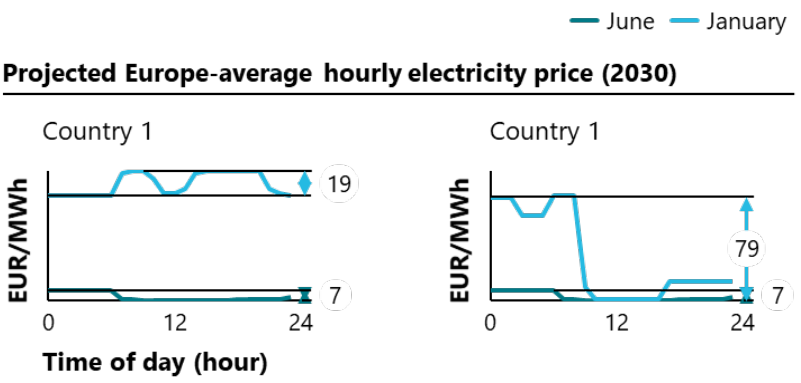
The following parameters are used:

- full-load hours: 2,600
- approximate maximum storage duration: 8.5 hours
- resulting interval length: 6 hours
- resulting power consumption time per interval: 1.8 hour

Based on the above parameters and the underlying exemplary price curve, an average saved-electricity cost of EUR 8.5 per megawatt hour is expected, resulting in a total revenue/reduced cost of EUR 22,000 per megawatt per year before subtracting any fees, taxes or other costs.

This value, however, is strongly dependent on various influences. For example, the spread between the highest and lowest prices on a given day strongly determines revenues but can vary significantly depending on variables like the share of solar energy and the implementation of transmission. As an illustration of this effect, see Figure 36 which shows the price spread for the same day in two different countries.

Figure 36. Spot-market price spread for two hypothetical countries on days in June and January.



Other points to consider include:

In addition to the calculated revenues, DHC networks with CHPs for heat generation can provide frequency restoration reserves (FRR) ancillary services to the grid.

Longer buffer times compared with other business cases may also provide more revenue, as they would increase the potential time frame during which energy can be shifted, but this depends on the technical setup at the specific DHC as well as the regulatory framework.

Depending on the system design (for example, sizing, heat sources and so forth), revenue may increase more in winter and spring, when the variability in power prices is highest.

A larger district heating area increases the profitability because it is more predictable and allows for scaling of fixed costs.

This business case is best executed in modern, low-temperature grids because they have better insulation performance, which reduces energy losses when not heating at full capacity, and because they can integrate a variety of distributed RES heating resources, including low-temperature heat pumps, which are well suited for flexibility.

Although the revenue saved looks positive, this assessment is highly uncertain because it is difficult to estimate underlying power prices and because revenue estimations are simplified, focusing only on wholesale revenues and ignoring cannibalisation effects within and across business cases.

6.5.2 Total cost of ownership for district heating and cooling

For calculating TCOO, an equipment lifetime of 16 years (based on the 2,600 operating hours per year used in Heat Roadmap Europe 4 modelling) has been assumed[109]. The influence of operating hours in the variable cost is dependent on the energy term (, while equipment lifetime would indicate the amortisation period for the equipment. The cost of flexibility by expense type is shown in Table 14.

[109] CRA-Carlo Ratti Associati et al., *Helsinki's Hot Heart: Decarbonising the City: And Making a Global Attraction*, winner, Helsinki Energy Challenge, January 2021, https://www.thehotheart.com/; and Paardekooper et al., *Heat Roadmap Europe 4*.

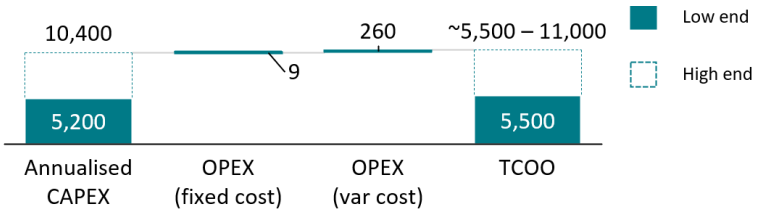
Table 14. Cost of flexibility for district heating and cooling by expense type[110]

Capital expenses (CAPEX)	Cost range		Unit
	Minimum	Maximum	
Buffer volume[111]	70,000	140,000	EUR/MW
Operating expenses (OPEX)			
Fixed cost	8.6	8.6	EUR/MWYE
Variable cost (2,600 hours)	0.1	0.1	EUR/MWh

Capital expenses exclude instrumentation and actuators, as remote control is assumed in modern, 4th generation district heating grids. A heat-to-power ratio of 1:1 using a combination of gas-fired CHP with heat recovery, electric boilers and heat pumps is assumed[112].

Total cost of ownership is estimated to end up between EUR 5,500 and EUR 11,000 per megawatt year. Details can be found in Figure 37.

Figure 37. Total cost of ownership for district heating and cooling, in euros per megawatt-year (EUR/MWYE)



Modern DHC operators can lower the capital intensity of district heating grids by downsizing the grid itself, upscaling the flexibility of buffer storage and participating in the flexibility market to increase revenue opportunities. This can drive the uptake of DHCs overall and can leverage economies of scale, because the current DHC market is highly fragmented[113].

This applies to 4th generation DHC networks, as efficient decoupling of heat demand and supply to provide power-grid flexibility requires well-insulated DHC grids, and traditional high-temperature, centrally heated district heating networks typically are not well insulated.

Although the additional cost of flexibility from the buffer volume of district heating and cooling is low, district heating grids are capital-intensive. Fourth-generation DHCs accommodate integration of low-temperature, decentralised heat generation from RES and are well-placed to incorporate storage for flexibility.

Analysis suggests few challenges in the economic assessment of district heating and cooling flexibility. Integrating flexibility into DHC is not technologically challenging, but feasibility depends

[110] Buffer volumes are technologically mature. As a result, we expect limited variability in TCOO, and we have not defined price scenarios in addition to the above summarised cost ranges.

[111] Pierre Attard et al., *METIS Study S9: Cost-efficient District Heating Development*, October 2018, https://www.researchgate.net/publication/331319841_METIS_Study_S9_Cost-efficient_district_heating_development; and Galindo Fernández et al., *Efficient District Heating and Cooling Systems in the EU.*

[112] Shunyong Yin, Jianjun Xia, and Yi Jiang, "Characteristics analysis of the heat-to-power ratio from the supply and demand sides of cities in Northern China," Energies 13, no. 1, 2020, https://doi.org/10.3390/en13010242.

[113] Lund et al., "4th generation district heating (4GDH): Integrating smart thermal grids into future sustainable energy systems," *Energy* 68, no. 15, April 2014, https://www.sciencedirect.com/science/article/pii/S0360544214002369.

on the DHC grid type (traditional, high temperature or modern, low temperature). Finally, profitability will be determined by fees, taxes and other expenditures.

6.6 Technical assessment for district heating and cooling

Three technical aspects of the business cases were assessed: flexibility response time to the trigger, or signal, from the TSO or DSO; availability throughout the day and year; and resilience to system instability (towards frequency variation, for example).

Flexibility response time to trigger, or signal, from the TSO or DSO. DHC flexibility requires a physical buffer volume and electrified heating or CHP, so that power demand and heat supply can be decoupled. As a result, response time to DSO triggers varies from seconds to minutes depending on the type of sources included in the heat supply[114]: (1) CHP can provide FRR immediately; (2) electric boilers and heat pumps can be switched off immediately and can ramp up to 100% in 30 seconds[115]; and (3) geothermal wells driven by electric pumps and CHPs ramp up or down within minutes.

Availability throughout the day and year. The availability of DHC flexibility throughout the day and year is generally expected to be quite good; a small buffer volume can typically provide flexibility for five to 12 hours, but a seasonal storage pit could also provide greater capacity[116].

As shown in Figure 38, DHC would have less availability only in the summer months as power flexibility is lower when there is less demand for heat – though that could be offset by higher demand for cooling. Actual availability depends on the system dimensions, including its configuration and buffer size.

Resilience to system instability. This business case is also expected to contribute positively to system stability. Buffering decouples the heat demand and grid load, reducing the impact of instability drivers to provide intra- and interday flexibility. CHPs can participate in FRR ancillary services, leveraging their rotational mass.

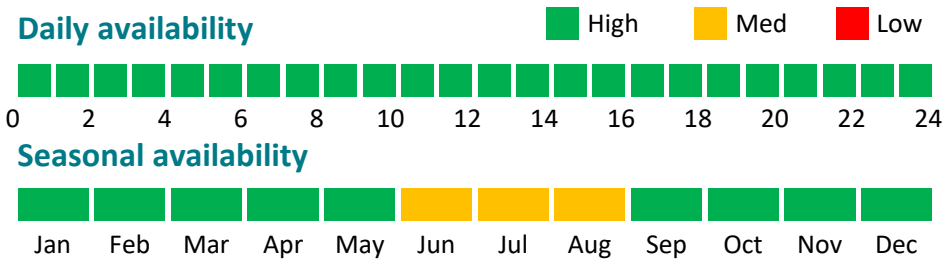
Analysis indicates low challenges in the technical aspects of leveraging energy flexibility from district heating, though its contribution to frequency stability services is limited to CHP and load reduction.

[114] Florin Iov, Mahmood Khatibi, and Jan Dimon Bendtsen, "On the participation of power-to-heat assets in frequency regulation markets: A Danish case study," *Energies* 13, no. 18, January 2020, 4608, https://doi.org/10.3390/en13184608.

[115] PARAT Halvorsen, https://www.parat.no/en/.

[116] IRENA, *Renewable Energy in District Heating and Cooling: A Sector Roadmap for Remap*, March 2017, https://www.irena.org/publications/2017/Mar/Renewable-energy-in-district-heating-and-cooling.

Figure 38. District heating and cooling availability throughout the day and year



6.7 Technical infrastructure required for district heating and cooling

The infrastructure required to implement this business case at any site can be divided into three categories: analog, digital and analytics:

- *Analog*. Buffer storage must be integrated into the heating and cooling network, and sensors and valves into the supervisory control and data acquisition (SCADA) system.
- *Digital*. On a digital level, integrating these systems into daily operations from process-optimisation and O&M perspectives is required. IT systems must be integrated, and robust cybersecurity systems must be instituted to ensure the safety of customer data and of stability support for TSO and DSO systems. Ancillary services systems must also be integrated, including the secure authorisation of TSO and DSO triggers and compatibility with district heating SCADA.
- *Analytics*. Analytics must integrate the system to external capacity and power markets, and to internal demand-forecasting and price-forecasting tools.

The few challenges that have been identified in technical infrastructure requirements centre on integrating district heating and cooling with TSO/DSO stability services and cybersecure remote control of electrified heat demand.

6.8 District heating and cooling risk considerations

Risks could be experienced in relation to varying regulatory standards, cybersecurity, public and user acceptance, and gamification potential. Four moderate risks and four low risks were identified. The moderate risks require significant resolution effort:

- *Regulatory*. Having different standards and prequalification requirements across Europe is a barrier for suppliers of demand-side flexibility equipment[117]. This lack of standardisation requires that providers of technology such as energy management systems and smart meters develop many new devices and systems[118].
- *Cybersecurity*. Increased use of ICT technologies for flexibility optimisation can increase the potential for cyberattacks that might disrupt heating and cooling. For example, in 2017 Næstved District Heating in Denmark experienced a cyberattack that required DHC operators to pay to access files that had been encrypted in servers[119].
- *Public acceptance*. Price and flexibility revenue transparency may be low due to the monopolistic nature of DHC systems; consumers cannot opt out of the existing system once their home is

[117] Prequalification is the formal approval that the capabilities assumed can indeed be provided by the asset of concern.

[118] European Smart Grids Task Force, *Demand Side Flexibility*.

[119] IRENA: *Renewable Energy in District Heating and Cooling*.

connected to it, or they can do so only at high cost, so the incentive may be low for operators to be transparent about "paying forward" gains achieved from flexibility in the form of reduced heat bills[120].

- *Gamification potential.* Longer-term flexibility compared with other industry players might risk gamification. Particularly within a small grid area with limited interconnections (for instance, the area of a specific DSO), a DHC operator might have sufficient maximum load and flexibility capacity to manipulate the market. For example, the operator could sap all remaining flexibility from the system to profit from high flexibility prices during periods of high grid load.

The four low risks can be resolved relatively easily:

- *Compliance.* District heating flexibility requires significant heat storage near consumers and perhaps related permitting[121]. Data privacy regulation is also relevant if DHC operators seek to gather data beyond aggregate consumption – for issues like improved forecasting, for example – in which case consumers might want the possibility of opting out. Generally, operations could be further optimised based on available data, primarily from the DHC's own network, though external data might help in the initial phase.[118] Open access to energy data is governed by privacy laws.
- *Cybersecurity.* Currently, cyberattacks on DHC plants are a low risk because market fragmentation and lack of standardisation should limit disruptions to small DSO grid areas. As fragmentation and standardisation are modernised, however, cybersecurity will have to be addressed.
- *Public and industry user acceptance.* In principle, all that would be required to increase flexibility in the existing heating network would be the addition of one or more storage volumes. Outside the scope of this project but highly relevant in moving to non-fossil heat generation is the integration of industrial waste heat into DHC networks. Social acceptance is affected by land-use competition, end-to-end sustainability of the heating mechanism, integration aesthetics and, in the case of high temperature (steam) heating, safety[122].
- *Gamification potential.* Because DHC operators typically act as a monopoly for the connected heat customers, policymakers could consider regulation to ensure fair treatment of customers (both around operations affecting their comfort as well as cost and benefit/revenue sharing).

[120] https://dbdh.dk/hacked-glad-we-have-your-intention-naestved-district-heating-cyberattack-response/

[121] IRENA, *Renewable Energy in District Heating and Cooling.*

[122] IRENA, *Renewable Energy in District Heating and Cooling*; Westera, "District heating ownership"; and European Smart Grids Task Force, *Demand Side Flexibility*.

7 Building energy management systems

Commercial space heating, ventilation and air conditioning (HVAC) are responsible for a significant share of energy consumption in the European Union. This business case focuses on HVAC's flexibility provision by shifting the demand and power load to building energy management systems (BEMS), which are computer-based monitoring and control systems that handle a building's electrical and mechanical equipment.

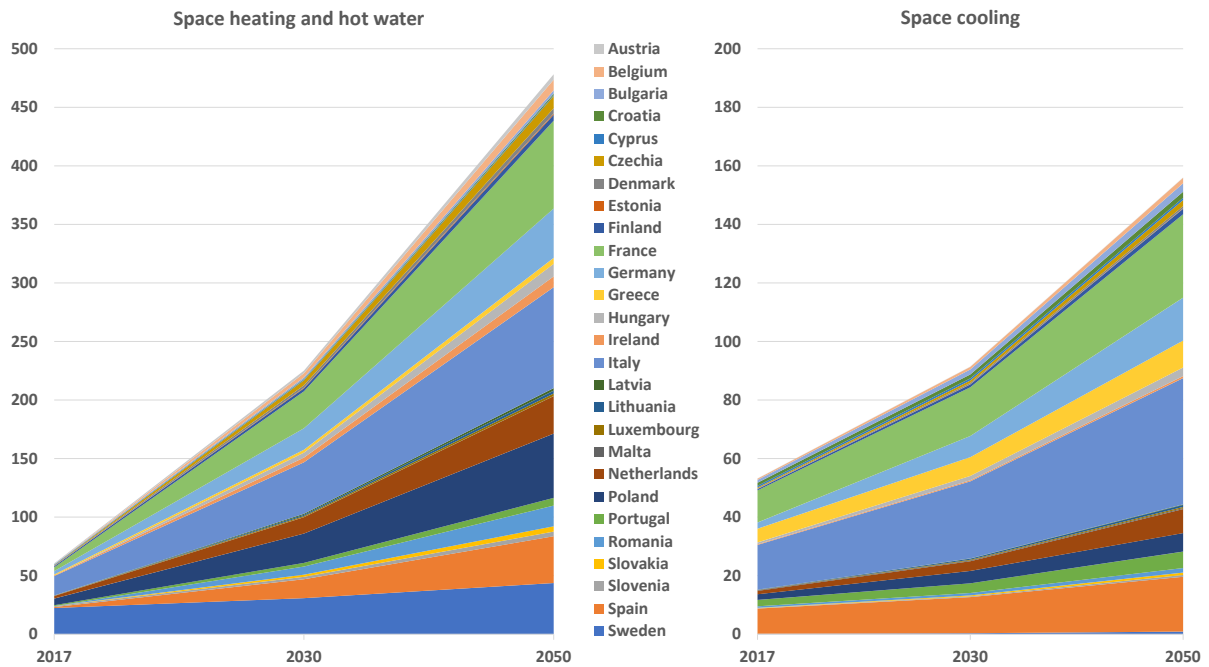
Calculations for 2050 final energy demand – or the energy required by consumers for end-use – for space heating, cooling and hot water were based on modelled scenarios from the EU-funded Efficiency First project, which aims to provide concrete, practical guidelines for making efficiency the top goal as energy systems are integrated going forward.[123] Analysis suggests that a 30% reduction in final energy demand – from 1,917 terawatt hours in 2017 to 1,343 terawatt hours by 2050 – can be expected, assuming the following conditions:

- commercial heat pump share of the final energy demand increases from 3.2% (61 terawatt hours) in 2017 to 35.6% (478 terawatt hours) in 2050
- commercial space cooling demand increases from 53.1 terawatt hours in 2017 to 155.9 terawatt hours in 2050
- electricity demand is calculated using an average coefficient of performance (COP) –the ratio of heating or cooling provided to electricity required to create it – of about 3, a typical value for the COP of air-source heat pumps
- heat pump and hot water demand in non-residential buildings grows in the European Union by a factor of eight from 2017 to 2050, with the largest markets in absolute terms found in France, Italy, Germany and Spain
- energy demand for space cooling grows strongly in all EU countries, increasing by factor of three
- targets set forth by the renovation wave strategy promoted by the European Commission – whose goal is to double the current average annual energy-refurbishment rate of 1% by 2030[124] – are considered

[123] Efficiency First, n.d., https://enefirst.eu/; and "Making Energy Efficiency First principal operational," project description, *CORDIS: EU Research Results,* Europa, n.d., https://cordis.europa.eu/project/id/839509.

[124] European Commission, Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee, and the Committee of the Regions, *A Renovation Wave for Europe – Greening Our Buildings, Creating Jobs, Improving Lives,* COM/2020/662 final, Document 52020DC0662, https://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1603122220757&uri=CELEX:52020DC0662.

Figure 39. Heat pump energy demand for space heating and hot water (at left) and for space cooling (at right) in non-residential buildings, in terawatt hours thermal



Six commercial building types in four European locations were modelled, taking into consideration climate zones, daily mean temperatures from 2010 (one of the coldest of the past 30 years) and various refurbishment standards to reduce demand and increase insulation capacities, or U-values.

For the estimation of overall BEMS flexibility potential by 2030 and 2050, the energy demand of heat pumps for space heating, cooling and hot water demand was considered. The buildings' thermal mass is considered thermal storage, with flexibility based on the time period required to heat or cool the building by 1 degree Celsius, from 20 degrees to 19 degrees. If the cooling time is more than two hours in each of the three six-hour flexibility blocks per day, the maximum flexibility time is six hours a day; if it is lower than two hours, the maximum flexibility time is three hours a day (or one hour in each of the three flexibility blocks).

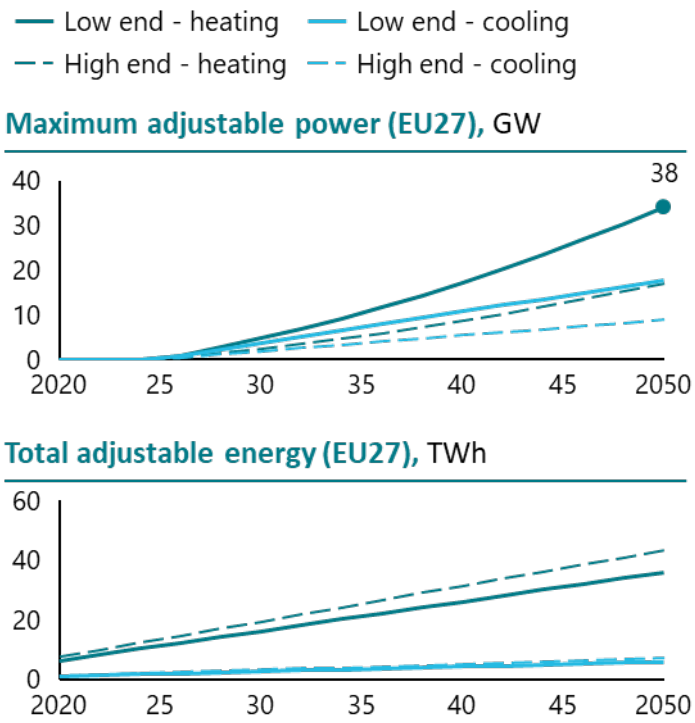
The flexibility assessment of the ventilation system is based on the ventilation time constant, which is defined as the time required for one full change of the building's indoor air. In practice, three full air changes are required to achieve a steady state. The ventilation time constant is calculated based on the building's typical floor area, height and ventilation rates, and its flexibility is determined in the same manner as overall BEMS flexibility. In other words, if the time for one full air change is more than two hours, then the ventilation can be turned off for one hour in one block; otherwise it can be turned off for two hours. The approximate maximum flexibility duration is between three and six hours per day (over three blocks of six hours each), with high seasonal fluctuations depending on location. The availability of a ventilation system based on the type of building is considered, and assumes that 50% of offices have a ventilation system in place, 30% of education buildings, 70% of health and social work buildings, 90% of hotels and restaurants, 80% of wholesale and retail spaces, and 80% of other types of non-residential buildings.

On average, between 2000 and 2020, there were 3,065 heating degree days and 90 cooling degree days a year in the European Union[125]. The resulting average full load is equivalent to 1,113 hours annually.

7.1 Potential time frame for BEMS impact

The maximum adjustable power from heat pumps and ventilation varying between 32.57 and 38.49 gigawatts, as shown in Figure 40.

Figure 40. Impact of BEMS flexibility on the European energy system



The increase in flexible power and adjustable energy is mostly due to the replacement of oil and coal boilers with heat pumps as old equipment becomes obsolete, as well as to higher building refurbishment rates after 2030 and increasing CO_2 prices. It is also expected that cooling demand will increase, providing additional flexibility.

The use of commercial BEMS for flexibility by 2050 can be realised through aggregators or via direct contracts with DSOs. Few challenges are expected to hinder the uptake of flexibility from commercial BEMS.

7.2 Market overview for BEMS

Today's utilities landscape and market structure vary by country, with DSOs ranging from mostly private to mostly publicly owned on a national or municipal level. Germany, for example, has a few large DSOs and many small, local ones; the Netherlands has a mix of DSOs, with the three largest

[125] Heating and cooling degree days are measures of how warm or cold a specific location is. They are calculated by looking at the amount (in degrees) and the time period (in days) that the outside air temperature was higher or lower than a specific reference temperature – in this case, 20 °C. Heating and cooling degree days are used to assess climate and to compare energy consumption among years and locations.

accounting for more than 60% of distributed power. Ireland has only one DSO, while France's dominant DSO handles more than 80% of distributed power.

Transmission system operators (TSOs) are also active in integrating BEMS into ancillary service markets and testing solutions in pilot projects. Most European countries have only one TSO, though some, like Germany, have more, and the relevance of TSOs as key players depends in part on regulatory policies.

As shown in Table 15, well-established BEMS market players include Schneider Electric, Siemens, Honeywell, Johnson Controls and Trane Technologies. In the past their focus was set on the building itself, and not on the provision of flexibility to the energy system, but they now cover a wide range of products such as BEMS software, controllers, HVAC equipment, local smart electric grid substations and field equipment like sensors, valves and actuators. Flexibility rates for heat pumps are slowly appearing in pilot projects, but there is still no market per se.

Table 15. Key stakeholders for BEMS flexibility

	Company	Headquarters
Utilities, TSOs and DSOs		
	EDF	France
	EnBW	Germany
	E.ON Group	Germany
	Iberdrola	Spain
	Ørsted	Denmark
	Tennet	Netherlands
BEMS manufacturers		
	Honeywell	USA
	Johnson Controls	Ireland
	Schneider Electric	France
	Siemens	Germany
	Trane Technologies	Ireland

More and more manufacturers have also begun to offer turnkey solutions such as energy-as-a-service (EaaS), a business model that offers RES with no upfront costs to customers. In the United States, for example, Schneider Electric (energy and digital automation) and Duke Energy Renewables (innovative wind and solar solutions) have collaborated to develop microgrid energy-as-a-service in two locations in Montgomery County, Maryland – a correctional facility and the public safety headquarters. The 25-year EaaS contract includes electrical distribution equipment upgrades, 2 megawatts of solar power, energy management with building automation systems, combined heat and power, and a gas generator for each location. A notable European EaaS project is a platinum virtual power plant developed by Siemens for the Sello Shopping Centre in Espoo, Finland, that is platinum-rated by the Green Building Council's Leadership in Energy and Environmental Design (LEED) certification program. The plant includes 550 kilowatts peak of photovoltaic power, intelligent LED lighting and 2 megawatts of electric storage capacity.

Analysis indicates few competitive challenges in the BEMS flexibility market because the technology is mature, large players and manufacturers are established, and many projects have been implemented – all factors that, along with EaaS, can accelerate market uptake.

7.3 Stakeholder mapping for BEMS

Stakeholders for this business case include commercial building owners, technology and service providers, knowledge institutions, governments and policymakers, and grid operators and electricity retailers and traders.

Commercial building owners. Commercial building owners could benefit from cost optimisation resulting from increased flexibility, increased efficiency through real-time interaction with building services and decreased facility management costs through remote operation and control. Adverse impacts for commercial building owners include increased risk of data breaches and the complexity of building services, which is highly dependent on software, automation, control and sensors.

- *Technology and service providers.* BEMS require investment in ICT platforms and smart connectable devices. Building owners must engage digitally with BEMS and connect with or provide digital platforms and digital infrastructure.
- BEMS suppliers can expect additional revenue streams from flexibility and by adapting to power market price forecasts, though BEMS that can react to external power-market triggers are more complex to operate and increase cybersecurity threats. BEMS suppliers should strengthen collaboration with facility companies and construction companies. Increasing the market for intelligent BEMS can lead to the development of compatible new energy-management hardware and software technologies for flexibility; improved operation and maintenance of heating, cooling and ventilation technologies are additional positive impacts. The main action required is the introduction of interoperable and IoT-connectable hardware such as smart sensors, and the development of software to facilitate intelligent BEMS, which encompasses not only smart systems but also learning capabilities.

Knowledge institutions. As part of the 2050 net-zero target set out in the Green Deal, the European Commission is promoting greater energy and resource efficiency through EU-wide initiatives, and BEMS are a key part of this activity. Their positive impact would be to facilitate the provision of flexibility from commercial buildings. Knowledge institutions like research societies and technical associations should work to develop cost-effective, intelligent BEMS with high-level indoor comfort that takes into account lessons learned from the COVID-19 pandemic. Such efforts could lead to design of new BEMS-connected building ventilation systems and mitigation strategies. Research on supportive hardware and software for BEMS and large pilot projects around energy flexiblity in buildings is expected to be ongoing.

Governments and policymakers. For European national governments, too, the implementation of BEMS can support the integration of renewable energy sources into the power system and help to optimise grid capacity through the electrification of heating and cooling. Actions required on the part of the European Union and of national governments include improving the digital infrastructure for buildings, strengthening the interoperability of BEMS-connectable devices, and providing financing and incentives for building renovations that include BEMS. Development of international BEMS standards is also needed, including possibly integrating BEMS with smart city or district concepts.

Adverse impacts for governments and policymakers could include the rebound effects of energy saving. Also, digital sufficiency can have negative environmental impacts; to minimise these, BEMS should be tailored to provide benefits beyond the energy saving and comfort – such as security, safety and productivity.

Grid operators and electricity retailers and traders. Positive impacts for grid operators include reduced congestion and increased flexibility through grid-responsive control strategies, though adverse effects may occur if initial investments were to outweigh efficiency gains. System operators should keep technical and market requirements for BEMS flexibility to a minimum to avoid unnecessarily high costs. Electricity retailers and traders should integrate BEMS into the energy market via demand-response services that improve forecast and market interaction through online platforms.

This mapping indicates that stakeholders may face moderate challenges. Stakeholders should collaborate to facilitate digital infrastructure for commercial buildings to realise the full potential of BEMS technologies. Data security also requires trust among stakeholders. BEMS flexibility assessment tools for automated energy-saving measurement and verification are required to integrate various stakeholders.

7.4 Innovation assessment of BEMS

A qualitative assessment, based on expert interviews and literature review, suggests that overall, BEMS innovations may face moderate challenges, principally in the interoperability among various smart appliances (sensors, thermostats, plugs and so forth) and the digital readiness of commercial buildings.

7.4.1 European innovative position of BEMS

The following aspects were taken into account while assessing innovation in Europe:

- *Market position of European firms.* European BEMS manufacturers, led by companies such as Schneider Electric, Siemens and ABB Ltd., cover a significant share of the global market. Leading markets in Europe include Germany, France and Italy.
- *Share of European firms in supplier and customer network.* The global BEMS network is dominated by Europe and is projected to grow at approximately 12% compound annual growth rate (CAGR) by 2027[126].
- *Level of innovation in the European Union.* Development of innovative BEMS – such as intelligent building management systems (IBMS), self-correcting intelligent building energy management systems (SCI-BEMS), smart grid–connected and intelligent context-awareness BEMS (ICA-BEMS) – is supported by various stakeholders, and a number of innovation projects[127] are supported by the European Commission[128], including an intelligent context-awareness system that increases energy efficiency and the EU Horizon project Heat4Cool, aimed efficient and cost-effective energy management solutions for buildings[129].
- *Enabling environments (research institutes, universities, think tanks).* Research institutes, universities and think tanks are collaborating with companies to develop sustainable and cost-

[126] *Global Building Energy Management Systems (BEMS) Industry*, ReportLinker, May 2021, https://www.reportlinker.com/p03646039/Global-Building-Energy-Management-Systems-BEMS-Industry.html.

[127] "Projects and sites overview," Smart Cities Marketplace, Europa.eu, https://smart-cities-marketplace.ec.europa.eu/projects-and-sites.

[128] Houssem Eddine Degha, Fatima Zohra Laallam, and Bachir Said, "Intelligent context-awareness system for energy efficiency in smart building based on ontology," *Sustainable Computing: Informatics and Systems Journal* 21, March 2019, https://www.sciencedirect.com/science/article/abs/pii/S2210537918303457#!; and, concerning the Horizon 2020 project, no. 723925, see "Self-correcting intelligent building energy management system (SCI-BEMS)," Heat4Cool, n.d., https://www.heat4cool.eu/technologies/energy-recovery/. See also "Projects and sites overview," Europa.eu.

[129] "The Heat4Cool Project," Heat4Cool, n.d., https://www.heat4cool.eu/about/.

effective active BEMS technologies[130]. The Technical University of Denmark (DTU), EnergyVille in Belgium, the Catholic University of Leuven (Belgium), and the Buildings Performance Institute Europe (BPIE; with offices in Belgium and Germany) are a few leading examples playing a vital role in BEMS research and innovation.

Demand-flexibility potential from BEMS is also addressed in various research pilots [131]. Organisations like the European Building Automation and Controls Association, Smart Energy Europe (smartEn) and the Federation of European Heating, Ventilation and Air Conditioning Associates (REHVA) are the main EU-wide collaborative platforms.

7.4.2 Spillover effects of BEMS

The following indirect benefits could emerge from BEMS innovation:

- *Reusability of infrastructure, data and research results.* BEMS require a large amount of data and installed IoT sensors to monitor and control building services. Such an infrastructure could be used to develop a next-generation energy management system and support the new energy services in commercial buildings.
- *Transferability to other industries.* BEMS are primarily used in commercial buildings like offices, hospitals, schools and supermarkets, with low transferability to other sectors, with the possible exception of greenhouse farming, where it can help maintain microclimates in an energy-efficient way[132].

7.5 Economic assessment of BEMS

The business case for flexibility provided by BEMS must be beneficial for building owners, energy-market actors and grid operators. Revenues for these stakeholders are the basis of the market for BEMS manufacturers and for aggregators that provide flexibility services. Figure 41 shows a schematic of the power and energy flow for the BEMS business case as well as the relevant players in each step.

End users (building owners) should notice no difference in comfort level or heating and cooling reliability, and they could probably expect lower consumption bills from providing flexibility to the grid.

BEMS manufacturers and aggregators can monetise the revenue opportunity from the supply and demand shift and aggregate consumption data. The viability and profitability strongly depend on system dimensioning, including buffer volume and electrified heating capacity, and on price spread and the consumption profiles of end users.

Energy providers are expected to pay aggregators or end users for the availability and use of flexibility capacity. Additional investment in smart-grid infrastructure is necessary to provide flexibility from all buildings to electricity markets.

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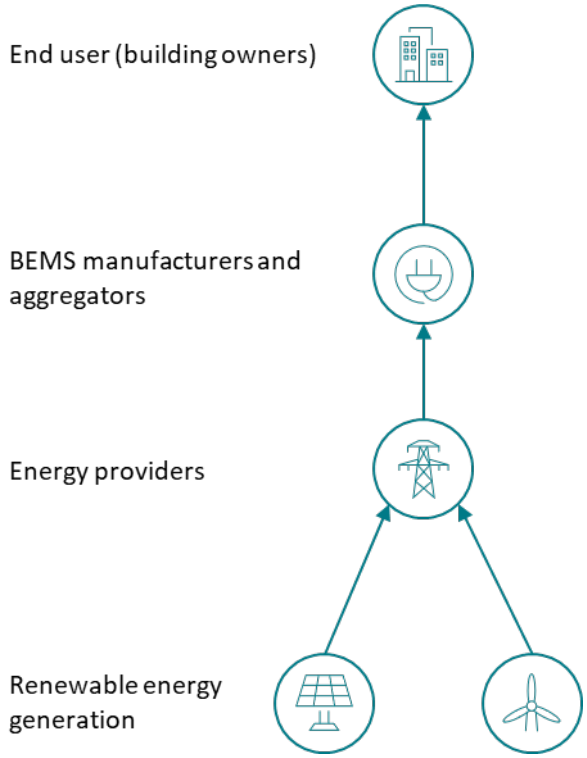
[130] "Self-correcting intelligent building energy management system (SCI-BEMS)," Heat4Cool; and HOLISDER, Integrating Real-Intelligence in Energy Management Systems Enabling Holistic Demand Response Optimization in Buildings and Districts, Horizon 2020 project 768614, https://cordis.europa.eu/project/id/768614.

[131] SmartEn, *Presenting the Value of Flexible Buildings*, smartEn Q&A paper, April 2021, https://smarten.eu/wp-content/uploads/2021/04/21-04-23_smartEn_QA_paper_FLEX_Buildings_FINAL.pdf.

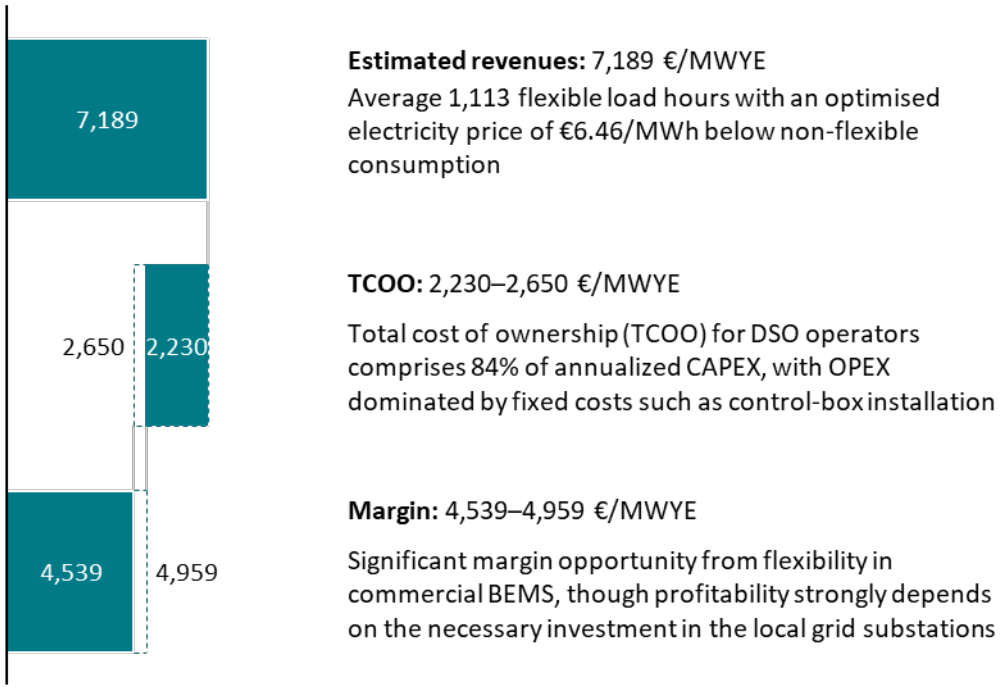
[132] See for example Adnan Rasheed, "A Review of Greenhouse Energy Management by Using Building Energy Simulation," Protected Horticulture and Plant Factory 24(4):317-325, https://www.researchgate.net/publication/296336480_A_Review_of_Greenhouse_Energy_Management_by_Using_Building_Energy_Simulation, https://www.sciencedirect.com/science/article/pii/S036013232100977X, and Joan Muñoz-Liesa et al., "Building-integrated greenhouses raise energy co-benefits through active ventilation systems," Building and Environment, 208, January 15, 2022, 108585, https://www.sciencedirect.com/science/article/pii/S036013232100977X.

Figure 41. Power and energy flow for the Building Energy Management Systems (BEMS) business case



The estimated operating margin shows that this business case can be profitable. Revenues are generated from purchasing electricity at lower costs and providing ancillary services to the grid. As shown in Figure 42, the profit margin from flexibility in commercial BEMS is significant – between 4,500 and 5,000 euros per megawatt year.

Figure 42. BEMS revenue and total cost of ownership, EUR/MWYE



Low to moderate challenges are expected in the viability of this business case because of the significant projected margin. Benefits from ancillary services strongly depend on the type of connection between the BEMS and the TSO/DSO and the necessary infrastructural investments in the local grid substations. Fees, taxes and other additional expenses might reduce the projected margin.

7.5.1 BEMS revenue

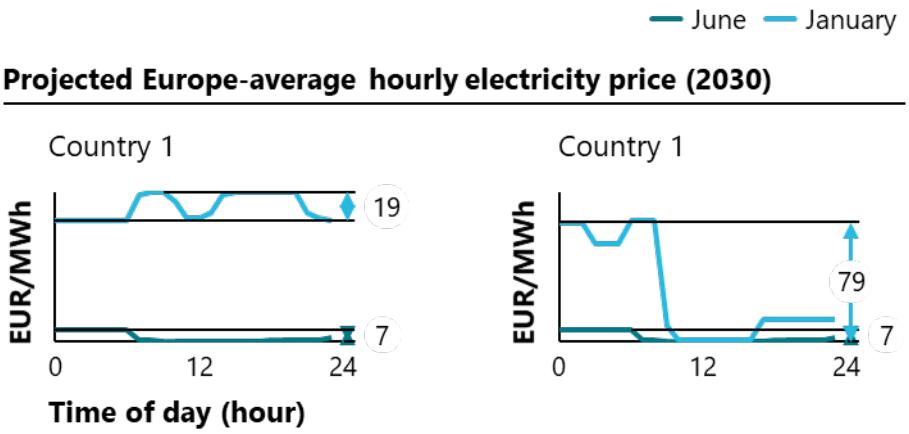
BEMS revenues were calculated using the same parameters as the assessment of flexibility, looking only at wholesale markets.

Revenues are generated by optimising the electricity purchase to hours with the lowest prices, and providing demand-response ancillary services in case of grid congestion. Installing large thermal storage could increase the profitability by extending heat pump flexibility with moderate fixed costs and better predictability. The flexible heat pump/chiller load is between 18% and 35% of the final energy demand for space heating and hot water depending on the type of building, refurbishment standards and location. If the time for one full air change is more than two hours, then the ventilation can be turned off for one hour; otherwise it can be turned off for two hours. In practice, three full air changes are required to achieve steady-state conditions.

Based on this assumption, an average of EUR 6.46 per megawatt hour can be saved, resulting in an estimated revenue of EUR 7,189 per megawatt-year.

In this model, the spread between highest and lowest prices on a given day has a strong influence on profitability and can vary significantly depending on the share of solar energy and the rate at which transmission infrastructure is built out. Figure 43 shows the price spread for two hypothetical countries on days in January and June. The average spread for both countries is EUR 7 per megawatt hour for a specific day in June and EUR 19 per megawatt hour for a specific day in January.

Figure 43. Price spread for two hypothetical countries on days in January and June



Overall, while the saved electricity costs look positive, this assessment is highly uncertain because it's difficult to estimate underlying power prices and revenue estimates are simplified, focusing only on wholesale revenues and ignoring cannibalisation effects within and across business cases.

7.5.2 Total cost of ownership for BEMS

Because investment costs relate to the purchase and installation of control boxes on the commercial building premises, the main hardware and software were identified for the TCOO calculation. Several ongoing pilot projects could change the connection between BEMS and the DSO, allowing the DSO to directly control and synchronise the BEMS activities with its own. This control would make the investment costs in control boxes obsolete.

Instrumentation such as smart meters, local smart grid substations, more distributed electricity generation, an increased number of EVs and charging infrastructure are excluded from the hardware costs as these are assumed to be present by 2030, with investment in them ongoing and distributed among business cases. It is assumed that no additional hardware is required, and that the average equipment lifetime is 20 years.

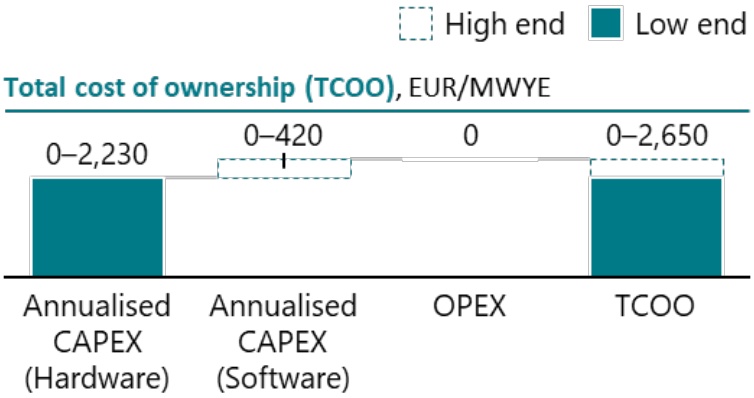
Table 16. Cost of BEMS flexibility

Capital expenses (CAPEX)	Cost range		Unit
	Minimum	Maximum	
Hardware: Control box (based on EUR 0 to EUR 850 and 23 kilowatt capacity per installation)	0	36,960	EUR/MW
Software: Network connection (based on EUR 0 to EUR 170 and 23 kilowatt capacity per installation)	0	7,390	EUR/MW

Apart from the hardware CAPEX, no OPEX costs are considered because the whole process is automated and no additional personnel costs are required for the day-to-day service of BEMS flexibility.

Based on the assumptions for capital expenses, the TCOO is estimated to be between EUR 2,230 and EUR 2,650 per megawatt year. Control boxes are mature and established technology and therefore should have limited variability.

Figure 44. TCOO for BEMS flexibility provision



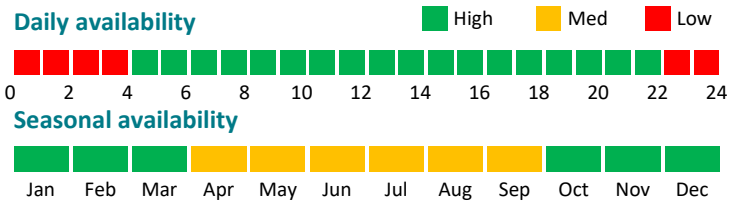
7.6 Technical assessment of BEMS

Three technical aspects of the business cases have been assessed: flexibility response time to trigger, or signal, from the TSO or DSO; availability throughout the day and year; and resilience to system instability (towards frequency variation, for example).

Heat pumps, chillers, cooling towers and ventilation systems can be switched off immediately and can fully ramp up in 30 seconds. If the building mass is used as thermal storage, the available load-shifting potentials are highly dependent on the outside temperature.

The availability of BEMS flexibility throughout the day and year is high, as shown in Figure 45, and thermal storage can provide flexibility for several hours, which would increase overnight availability as well. Power flexibility is lower in summer because of lower heat demand, though that is mostly offset by higher demand for cooling. Actual availability strongly depends on the building type, geographical location and system dimensions.

Figure 45. Availability of flexibility from BEMS throughout the day and year



Support to system stability is also high for BEMS, which can provide intra- and interday flexibility and can adapt to support an optimised power flow, which is used to determine the best power-plant operating levels and leads to lower electricity production cost.

Depending on the thermal storage availability and control strategy, the storage can be used to provide a positive control reserve in the case of under-frequency (below 50 hertz) or negative control (above 50 hertz).

Analysis suggests few challenges in the technical aspects of leveraging energy flexibility from commercial BEMS.

7.7 Technical infrastructure required for BEMS

The technical infrastructure needed for BEMS is both physical and digital.

Analog. The physical infrastructure for grid integration includes an upgraded grid connection and perhaps a local smart grid substation, depending on the DSO network. BEMS operators must ensure safe and reliable remote operational control. Depending on the connection between BEMS, aggregators and the TSO/DSO, additional infrastructure is required both in the grid (smart grid local substation) and at customer premises (control box and smart meter).

Digital. The digital infrastructure includes integration into aggregator and TSO/DSO systems and requires robust cybersecurity; without it, the grid could be destabilised. Integrating ancillary services systems requires secure authorisation of TSO/DSO triggers and compatibility with the BEMS control system. Integration with external capacity and power markets is also necessary for accessing analytics tools.

Low to medium challenges are expected in the technical infrastructure requirements.

7.8 BEMS risk considerations

The main risks in the BEMS business case are in regards to cybersecurity threats and in relation to the regulatory framework, if standards and prequalification requirements are not harmonised across Europe. Analysis indicates moderate risks and significant resolution effort in the following areas:

- *Varying standards*. Different standards and prequalification requirements across Europe may pose regulatory risks that could create a barrier for suppliers of demand-side flexibility products[8]. Efforts are needed for defining unified standards on which the TSO/DSO can access and control the BEMS schedule. The business case of flexible BEMS would improve as EU-wide solutions become available.
- *Cybersecurity*. Cyberattacks result from increased use of ICT for flexibility optimisation. For example, in 2017, Næstved District Heating in Denmark experienced a cyberattack that required district heating and cooling operators to pay to access files that had been encrypted in the servers[133].

The low risks, which can be resolved with minor efforts, are:

- *Performance baselining*. Allocation of energy volumes, appropriate and transparent baselining methodology and fair remuneration levels are major issues in allowing easier entry for new market participants[134].
- *Cybersecurity*. Data privacy regulation is relevant because flexibility requires increased sharing of data. Lack of customer trust in the equipment and the fear of cyberattacks would certainly reduce participation in the flexibility market. A number of questions remain concerning who gets access to the data, which data is public, who can share the data, and who is responsible for it. Providing clear and standardised answers to these questions could increase customer trust. Cyberattacks on the electrified heating and cooling supply – perhaps directed explicitly

[133] European Smart Grids Task Force Expert Group 3, *Demand Side Flexibility: Perceived Barriers and Proposed Recommendations*, European Commission, 2019.

[134] Ibid.

against heat pumps – are a potential risk for the electric grid, though the risk is low because of market fragmentation and standards that might limit such attacks to selected local grid areas.

Public and user acceptance. Because the value of flexibility is low in the building sector (due to a lack of clear information regarding opportunities available and regarding costs and benefits), customers may not see the benefits of participating in the market. Acceptance would change over time with a higher penetration of renewable electricity, but a clear revenue stream is necessary to engage customers.

The commercial sector also suffers from low customer awareness about the opportunities to engage in demand-side response. Customers lack technical knowledge regarding how they could contribute to the flexibility market, and installers and service providers will need to provide clear explanations of the products. Finally, social acceptance is influenced by the awareness of climate change, meaning public education campaigns might be useful.

Gamification potential. There are minor risks for gamification and strategic bidding, but no malicious intent is foreseen through the gamification process because end users cannot manipulate the power market to benefit themselves.

All risks appear manageable and do not represent showstoppers for the flexibility provision of BEMS.

8 Business case: Industrial hybrid heating

Industrial consumption makes up a significant share of overall energy and electricity use. A hybrid system for process heating allows for electric-element or electrode boilers to be used when electricity is cheap and for fossil-fuel boilers to be used when prices are higher. This can serve as a transitional solution, as it still results in some emissions. Switching between fossil-fuel boilers and electric not only can help make savings but also can help to balance the grid by increasing or decreasing the electric load at times of excess or scarcity in the electricity supply. Hybrid heating systems for industry can contribute to the overall energy transition as well as Fit for 55 and the Green Deal in two ways: (1) They decarbonise heating, which currently relies on fossil-fuel combustion, to some extent, and (2) they provide greater flexibility in balancing the industrial power load. A significant number of hybrid heating systems are currently deployed in industry, with electric boilers providing low and medium heat up to 400 °C.

This business case, which falls under the industrial load control use case, focuses on the impact of hybrid heating systems using electric boilers for low-temperature and medium-temperature (LT/MT) heat. Industrial heat pumps can replace electric boilers in LT/MT heat once they are commercially available, but for now they're excluded from this business case.

8.1 Potential time frame for industrial hybrid heating impact

Based on industry-sector GDPs, the countries with largest potential for this business case are Germany, France, Italy, Poland and Spain. Because of its large economy and diverse industrial sector, Germany is used as an example for exploring the time frame for electric boilers to make an impact. The Germany Figures are then extrapolated to give a picture of potential industrial heating capacity EU-wide.

In 2016 the German government released its Climate Action Plan 2050[135], which posits a target of 80% to 95% lower greenhouse-gas emissions by 2050 compared with 1990 numbers. In the first scenario, 100% electrification of LT/MT heat demand is achieved by 2050, in line with Germany's and the European Union's climate-neutrality goals. In the second scenario, 50% electrification of LT/MT heat demand is achieved by 2050, providing an overall industrial electrification rate of 45%, with hydrogen, for example, acting as an alternative to electrification. This is in line with the German government's 80% scenario.

Two more parameters were added to the time frame calculation. First, how much industrial heat is produced, or partially produced, by electricity, and second, how many of these electrified heat generators are part of a hybrid, rather than fully electric, system?

Different assumptions were made for the short term (before around 2040) and the long term (after around 2040) regarding the adoption of industrial hybrid heating systems.

In the short term, a 100% adoption rate of the hybrid model for sites that apply electrification is assumed, as it reduces exposure to price fluctuations on the wholesale power market.

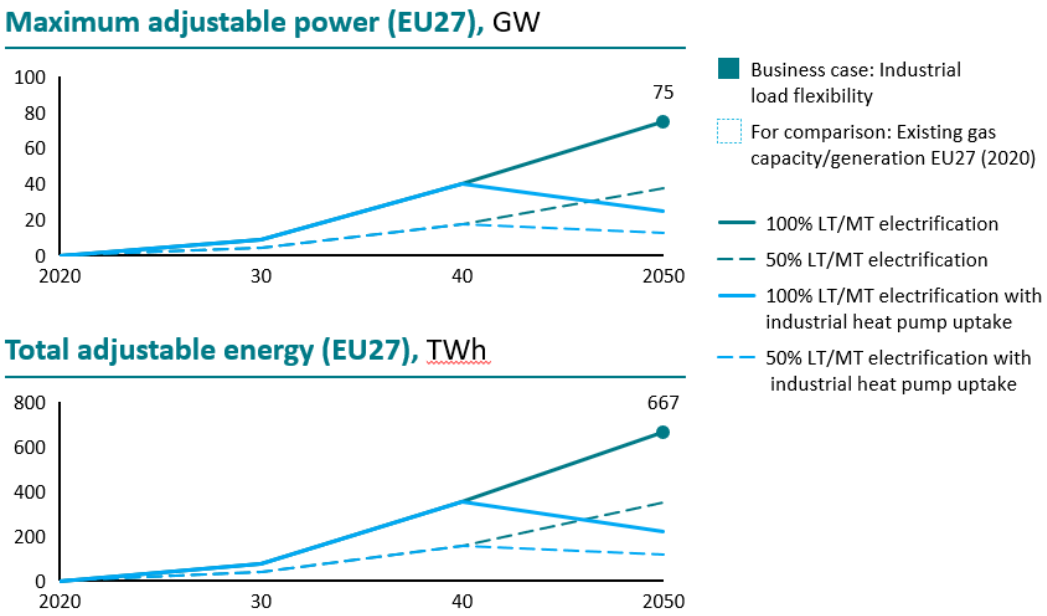
In the long term, a moderate adoption rate of 50% is assumed. This would likely entail electrifying the baseload and using fossil fuels for flexibility on the more seldom occasions when they are cheaper (even including the emissions penalty). The other 50% would be fully electrified using

[135] Federal Ministry for the Environment, Nature Conservation, Nuclear Safety and Consumer Protection, Roadmap to a Climate-Neutral Germany: Climate Action Plan 2050: Germany's Long-term Low Greenhouse Gas Emission Development Strategy, 2016, https://www.bmu.de/en/topics/climate-adaptation/climate-protection/national-climate-policy/climate-action-plan-2050-germanys-long-term-low-greenhouse-gas-emission-development-strategy.

industrial heat pumps, which industry experts expect will be three times more efficient than electric boilers. Based on the state of innovation for heat pumps to provide heat above 150 °C, following the learning curve and maturation, this could apply at scale in industrial applications beyond 2040; however, it is out of scope for this business case.

The potential outcomes resulting from the various scenarios described here are shown in Figure 46.

Figure 46. Impact of industrial hybrid heating flexibility on the European energy system[136]



8.2 Market overview for industrial hybrid heating

The market for industrial electric boilers for hybrid heating systems is growing, with specialised industrial-equipment manufacturers providing electrode boilers for industrial applications[137].

Equipment manufacturers are established predominantly in Europe and United States, as shown in Table 17, and they operate internationally, installing systems beyond their home markets. More than half (six of 11) of the identified manufacturers are based in the European Union, with two in Norway and Switzerland, which are not part of the European Union, and two in the United States. It is worth noting that traditional providers of industrial power equipment, like GE and Siemens, are not yet participating in the electric boiler/steam market.

[136] IEA, "Installed capacity in the European Union, 2000–2010, and projections up to 2040 in the Stated Policies Scenario," October 2020, https://www.iea.org/data-and-statistics/charts/installed-capacity-in-the-european-union-2000-2010-and-projections-up-to-2040-in-the-stated-policies-scenario; and Sia Partners, "Demand response: A study of its potential in Europe," Insight Energy & Environment, December 2014, https://www.sia-partners.com/system/files/document_download/file/2020-06/20141218_Article_DR-potential-in-Europe-1.pdf.

[137] "Global industrial boiler market 2019–2023: Industry analysis and forecast – Technavio," Business Wire, January 2019, https://www.businesswire.com/news/home/20190108005663/en/Global-Industrial-Boiler-Market-2019-2023-Industry-Analysis-and-Forecast-Technavio.

Table 17. Manufacturers of industrial electric boilers by market size[138]

Company	Headquarters	Revenue (mEUR)
Zander and Ingeström	Sweden	16.3 (2019)
Parat	Norway	14.8 (2019)
Cerney	Spain	8.9 (2019)
ATTSU	Spain	6.2 (2019)
Danstoker	Denmark	3.0 (2020)
Vapec	Switzerland	1.6 (2020)
BVA Elektrokessel	Germany	1.5 (2016)
AB&Co.	Denmark	0.5 (2020)
Vapor Power International	USA	n/a
Lattner Boiler Co.	USA	n/a
Allmech	South Africa	n/a

Table 18. A deeper dive on some leading electric boiler manufacturers

Company	Description	Projects
Zander and Ingeström	Zander and Ingeström manufactures electric boilers, pumps and water tanks. Unit capacity of electric boilers is up to 70 megawatts and 65 barg steam pressure.	Applications include district heating and steam boilers for nuclear plants and the food-processing industry.
Parat	Parat is a manufacturer of steam and heat solutions for on- and offshore industries. Unit capacity is up to 60 megawatts and 85 barg steam pressure[139].	Applications include district heating, hospitals, agriculture, food processing and the paper industry.
Vapec	Vapec installations provide 70 megawatts of balancing power in the German power grid.	Applications include district heating, food-processing industries and nuclear backup steam generation.
Vapor Power International	Vapor Power manufactures electrode boilers of up to 35 megawatts and 35 barg of steam pressure.	Applications include process heat and steam for breweries and distilleries, healthcare and the paper industry.

Analysis shows the competitive landscape of industrial hybrid heating systems does not present many insurmountable challenges to the adoption of hybrid heating flexibility capacity through electrification. The growth market does not appear to be dominated by too small a number of players; manufacturers originate from three continents and report a significant number of commercial installations beyond their home markets.

[138] "Amadeus: European Company Data," database, European University Institute, n.d., https://www.eui.eu/Research/Library/ResearchGuides/Economics/Statistics/DataPortal/AmadeusBvD; "Willkommen in der D&B Firmendatenbank!," Dun & Bradstreet/Firmendatenbank, https://www.bisnode-firmendatenbank.de; and "Welcome to the world of Creditreform," company profiles database, Creditreform International, n.d., https://www.creditreform.com/.

[139] Barg is the unit of measure for gauge pressure, equal to absolute pressure minus atmospheric pressure.

8.3 Stakeholder mapping for industrial hybrid heating

Stakeholders for this business case include society, government, business (specifically, operators of industrial hybrid heating systems) and the power sector (specifically, TSOs and DSOs).

Society. At the societal level, a potential impact is that industrial hybrid heating systems will strengthen the competitive position of energy-intensive industries, which might protect local jobs for local communities. In addition, it is possible that the initial reduction of CO_2 emissions will be accelerated as hybrid systems become more affordable than full electrification. However, adoption of hybrid systems could also result in the delayed reduction of fossil-fuel CO_2 emissions compared with full electrification. To ensure support, industries deploying hybrid heating may need to engage with local communities around the benefits and then, once systems are in place, make its impact transitional and transparent on an ongoing basis.

Government. For both the European government and national governments, hybrid heating systems could help increase grid flexibility as industry moves towards full electrification, driving grid stability and adoption of renewables. However, there may be a delayed reduction of fossil-fuel CO_2 emissions compared with full electrification. Also, connecting the grid to the new flexibility platform will require an online intermediary, which could present a cybersecurity risk both for each industry individually and for the grid as a whole. Government support of demonstration projects could support adoption at scale[140].

Business. At the industry level, a key impact for operators of hybrid heating systems is the opportunity to monetise the power price spread and reduce the power price market exposure risk relative to full electrification. However, industrial operators are exposed to increased system complexity and cybersecurity risk. To address these challenges, players could focus on creating system flexibility, redesigning primary processes, exploring new business models and improving cooperation among stakeholders across the value chain.

Equipment suppliers will see increased demand for innovative products like industrial heat pumps and efficient hybrid systems. However, product demand depends on the competitiveness of hybrid solutions, and is linked to uncertain power and fuel prices. To address such unknowns, suppliers could focus on developing scalable technology and business-case demonstration projects on, for example, capacity trading and continuous energy-balance optimisation.

Research institutes may see increasing demand for technological innovations and knowledge sharing across industries. A focus on stimulating the development of promising technologies and demonstration projects could be beneficial[141].

Power sector. At the power-sector level, grid operators (TSOs and DSOs) will likely profit from increased grid flexibility relative to the full electrification of industry. However, initial uncertainty could be caused by the need to explore new business models for local flexibility management.

For energy producers, increased electrification for flexibility purposes could act as a floor price in the power market. Producers could further improve cooperation among stakeholders by increasing intersectoral knowledge sharing and by leading multidisciplinary pilots.

Moderate challenges may emerge from the stakeholder landscape for the adoption of hybrid heating for power flexibility in industry. Lack of coordination and information on technical feasibility

[140] Berenschot, Electrification in the Dutch Process Industry: In-depth Study of Promising Transition Pathways and Innovation Opportunities for Electrification in the Dutch Process Industry, February 2017, 10, https://blueterra.nl/wp-content/uploads/2018/03/Electrification-in-the-Dutch-process-industry-final-report.pdf.

[141] Ibid.

are often mentioned as possible impediments. TSOs, DSOs and industrial operators of hybrid heating systems are the most directly affected stakeholders.

8.4 Innovation assessment of industrial hybrid heating

A qualitative assessment, based on expert interviews and literature review, suggests an overall low risk in the role of European innovation for the adoption of hybrid heating systems for industrial application. European firms are well positioned to bring innovation to practice in industry and to support uptake at scale in the European Union. Electric boilers are already used at scale in commercial application, and industrial heat pumps are in development.

8.4.1 European innovation position of industrial hybrid heating

The following aspects were taken into account while assessing innovation in Europe:

Market position of European firms. Many of the firms in equipment manufacturing and the industrial process application of electric boilers for LT/MT heating are European. The top seven manufacturing players have already delivered approximately 100 commercial applications in Europe.

Share of European firms in the supplier and customer network. Eight of the 11 key players listed in Table 17 are on the European continent; of them, six are in EU member states. Equipment manufacturers coordinate the full process of systems design, manufacturing and installation or integration; they cover the entire value chain. Industrial players in Europe are already starting to implement hybrid heating in LT/MT systems to provide power flexibility services to the grid.

Level of innovation in the European Union. Companies within the European Union market exhibit a high level of innovation, as observed in both technological development and in techno-economic research-institute analyses of systems-design innovation. In addition to the low- and medium-temperature heating applications considered in this project, companies such as BASF, Linde, Shell, AkzoNobel and Borealis have made significant innovations in high-temperature applications[142].

Enabling environments (e.g. research institutes, universities, think tanks). European universities, applied research institutes and industry collaborate closely. One result of such collaborations has been the creation of hubs with internet of things (IoT) start-ups implemented by universities and research institutes such as the Delft University of Technology (TU Delft) in the Netherlands; Chalmers University of Technology in Gothenburg, Sweden; TNO-ECN (VoltaChem programme) in the European Union; and Sintef in Norway[143].

[142] Thomas Nonnast and Birgit Hellmann, "BASF, SABIC and Linde join forces to realize the world's first electrically heated steam cracker furnace," BASF, March 2021, https://www.basf.com/global/en/who-we-are/sustainability/whats-new/sustainability-news/2021/basf-sabic-and-linde-join-forces-to-realize-wolds-first-electrically-heated-steam-cracker-furnace.html; and "Dow and Shell team up to develop electric cracking technology," Shell, June 2020, https://www.shell.com/business-customers/chemicals/media-releases/2020-media-releases/dow-and-shell-team-up-to-develop-electric-cracking-technology.html.

[143] Yasmine Abdallas Chikri, "Hybrid boiler systems in the Dutch industry: A techno-economic analysis of the potential of hybrid boiler systems to cost-effectively decarbonise steam generation in the Dutch industry," master's thesis, TU Delft, Delft, Netherlands, February 2020, https://repository.tudelft.nl/islandora/object/uuid%3A138874fa-32d2-4319-80fa-c089c3feef72; Malin Kerttu, "Evaluation of electric and hybrid steam generation for a chemical plant under future energy market scenarios," master's thesis, Chalmers University of Technology, Gothenburg, Sweden, 2019, https://core.ac.uk/display/199377666; Colin McMillan et al., *Opportunities for Solar Industrial Process Heat in the United States*, NREL/TP-6A20-77760, National Renewable Energy Laboratory/US Department of Energy, February 2021, https://www.nrel.gov; and Jack Deason et al., "Electrification of buildings and industry in the United States: Drivers, barriers, prospect and policy approaches," LBNL-2001133, Lawrence Berkeley National Laboratory, March 2018, https://eta-publications.lbl.gov/publications/electrification-buildings-and.

8.4.2 Spillover effects of industrial hybrid heating

The following indirect benefits could emerge from innovation in industrial hybrid heating:

Reusability of infrastructure, data and research results. Overarching control systems optimisation and cybersecure systems integration have applications beyond industrial heating; however, electrification of industry applications is highly industry-specific and does not generate much spillover effect.

Transferability to other industries. As other sectors move towards lower-temperature heating for both residential and commercial uses, and only selected processes in industry require medium- or high-temperature heating, the innovative technologies for industrial boiler electrification will have some, but not full, transferability across industries.

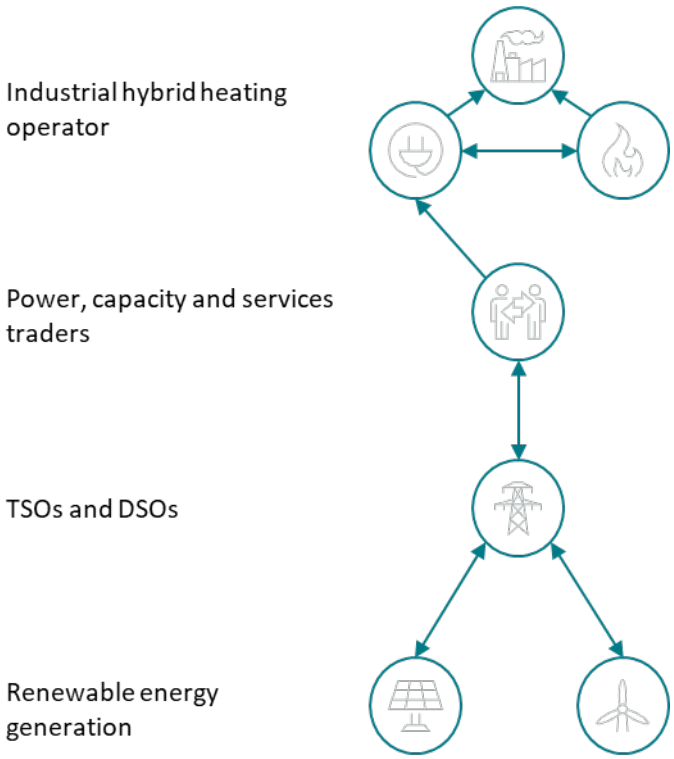
8.5 Economic assessment of industrial hybrid heating

In this business case, the two key players are the industrial hybrid heating operators and the power, capacity and services traders. The industrial hybrid heating operators can monetise the dynamic price spread of power (for example, intra- and interday and congestion management) and the price variability of fuels, both fossil and non-fossil (such as hydrogen and biogas). The power, capacity and services traders link supply and demand on timescales from seconds to days (intra- and interday, congestion management and frequency-stability services, if applicable).

The analysis did not examine the internal relationship between the two key players further because it is likely that the described profits, costs and risks are shared between them based on the specific business model they negotiate.

Figure 47 shows a schematic of the power and energy flow for this business case as well as the players relevant in each step.

Figure 47. Power and energy flow for the industrial hybrid heating business case



The other key players – TSOs, DSOs and renewable energy sources operators – will also affect and be affected by the potential adoption of this business case:

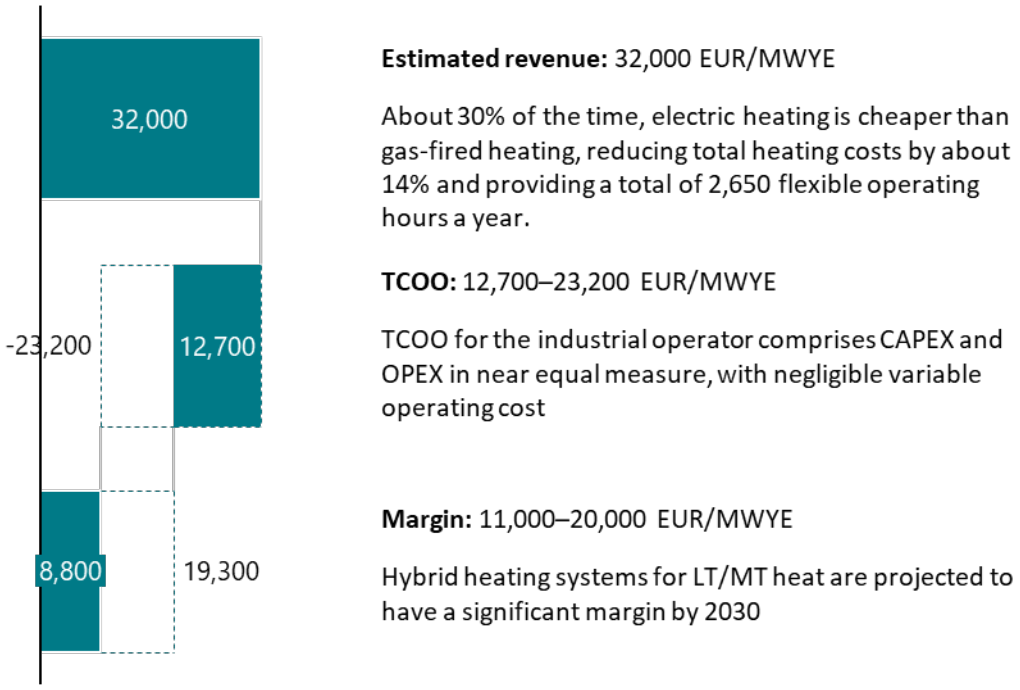
TSOs and DSOs can leverage industrial load flexibility to balance supply and demand in the power grid.

RES operators run renewable-power-generation capacity and inherently cause variability in supplied power, thereby increasing the attractiveness of this business case because of lower power prices at certain times. They may also profit from industrial-load flexibility from hybrid heating systems. In the past, demand increased supply; but now, because of volatile production, there are times when more energy is produced than is needed, which drives prices down at those times. It is now possible to intentionally increase demand at those times, which can cause prices to increase, thereby increasing RES remuneration.

The key players – the industrial hybrid heating operators and the power, capacity and services traders – are expected to share the majority of revenue opportunity and cost. Estimates of revenue and total cost of ownership are shown in Figure 48, which is explained in detail in sections 7.5.1 and 7.5.2.

Analysis suggests that challenges to the viability of this business case are likely to be moderate. Industrial hybrid heating systems for LT/MT heat are projected to have a strong margin by 2030, though fees, taxes and other expenditures might significantly reduce this margin.

Figure 48. Revenue and total cost of ownership, EUR/MWYE



8.5.1 Industrial hybrid heating revenue

Revenue is calculated based on a projected European average hourly price curve for 2030, also used for other business cases in this report. The price curve is derived from a European energy-system model that considers wholesale-based hourly electricity demand and supply from a power mix including conventional and renewable energy sources as well as batteries. Transmission (and therefore congestion) is regarded between countries only.

The calculation for this business case assumes that heating is switched to electricity whenever electricity is cheaper than gas from the points of view of both overall efficiency and pure energy price. Note that for this business case, no revenue is generated from providing power flexibility; rather, cost savings are achieved through optimising heating operations.

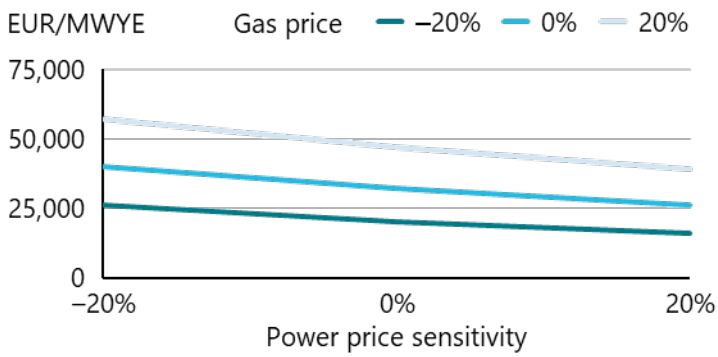
The following parameters were used:

- gas price: EUR 24 per megawatt hour
- industrial gas boiler efficiency: 95%
- electric boiler efficiency: 100%
- full-load hours: 8,760 (24/7 operation)

Based on these parameters and the underlying price curve, it is possible to estimate that electric heating would be cheaper than gas heating approximately 2,700 hours per year. The average cost of electricity used in these hours is EUR 13 per megawatt hour. Therefore, the estimated revenue from reduced energy costs totals EUR 32,000 per megawatt a year before subtracting any fees, taxes or other costs.

This modelling approach is highly approximate, and numerous factors can significantly impact results. For example, deviations of ±20% in gas and power prices lead to a total range of EUR 16,000 to EUR 57,000 per megawatt-year in possible revenue outcomes, keeping the remaining assumptions and calculation methodology unchanged, as shown in Figure 49.

Figure 49. Estimated revenue sensitivity regarding gas and power prices



Other points to consider include:

The monetisation opportunities presented by using industrial hybrid heating flexibility depend on the future price spread (difference times duration) between electricity and fossil fuels or green hydrogen, as well as on fees and compensation incentives from the TSOs and DSOs for issues like congestion management and ancillary services.

The potential benefit industrial hybrid heating systems could have over other flexibility sources is that there is no technical limit to the duration of flexibility; it is driven only by economics.

Hybrid heating systems may be well-placed to navigate the uncertain dynamics of carbon-tax and power-market price fluctuations and to reduce the risk of energy-intensive industries moving to countries or regions with low or no CO_2 tax.

Local viability may vary owing to location-based power pricing.

Although revenue potential looks positive, this assessment is highly uncertain due to significant uncertainty in estimating the underlying power prices, along with simplified estimations of

revenues; for instance, it focuses only on wholesale revenues and ignores cannibalisation effects within and across business cases.

8.5.2 Total cost of ownership for industrial hybrid heating

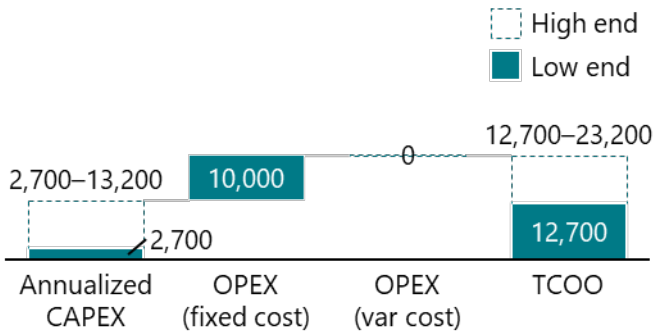
For calculating TCOO, a typical equipment lifetime of 15 years is assumed, and it is further assumed that existing boilers will be replaced by hybrid equivalents when calculating CAPEX and OPEX. Other key assumptions for this calculation can be found in Table 19.

Table 19. Cost of industrial hybrid heating flexibility[144]

Capital expenses (CAPEX) [145]	Cost range		Unit
	Minimum	Maximum	
Electric boiler	22,000	110,000	EUR/MW
Control box system	12,000	60,000	EUR/MW
Grid connection cost[146]	500	14,000	EUR/MW
Operating expenses (OPEX)			
Fixed cost	10	10	EUR/MW
Variable cost	~0	~0	EUR/MW

Based on the analysis, annualised CAPEX may increase by up to EUR 1,000 per megawatt-year year if additional grid connections are required. The total cost of ownership will therefore be between EUR 13,000 and EUR 23,000/MW a year, as shown in Figure 50.

Figure 50. Total cost of ownership for industrial hybrid heating, EUR/MWYE



Due to the opportunity to redesign primary processes, hybridisation of heating systems is expected to take place predominantly at the current equipment's end of life. System updates at other times might cause increases in capital expenditure (and write-offs), decreasing the business case's viability. In the long run, it is assumed that the adoption of higher-efficiency heating pumps does

[144] See McMillan et al., *Opportunities for Solar Industrial Process Heat in the United States*. Electric boilers are technologically mature and do not depend on rare metals or resources in large quantities; as such, we expect limited variability in TCOO.

[145] Marc Marsidi/TNO-ECN, "Electrical industrial boiler," technology factsheet, May 2019, Technology-Factsheet-Electric-industrial-boiler-1.pdf; and "Costs of a grid connection," TenneT, https://www.tennet.eu/electricity-market/connecting-to-the-dutch-high-voltage-grid/costs-of-a-grid-connection/.

[146] Range is based on EUR 5,000 for 10 megawatts small application and EUR 1 million for 70 megawatts large application. See TenneT, https://www.tennet.eu/.

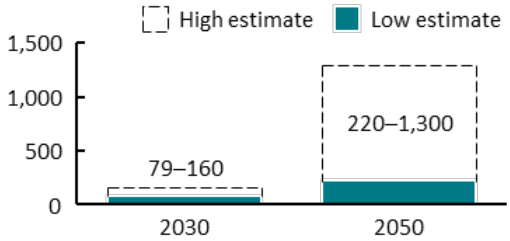
not lower the CAPEX. Although efficiency increases by a factor of about 3, the expected higher CAPEX is assumed to negate this increase. As industrial heat pumps are not yet widely available, this assumption will be updated in future reviews of this economic assessment.

Research by institutes like TU Delft shows that hybrid boilers can be a cost-effective decarbonisation strategy for industry, subject to currently uncertain prices of electric power and fossil fuels and to carbon taxation. It is estimated, however, that in the long run, full electrification (without hybrid flexibility) will become more economical for operators of industrial process heat[147].

Moderate challenges may emerge in the economic assessment for electrification to convert to LT/MT industrial hybrid heating systems. In addition to capital expenses for system conversion, grid connection costs may be significant, depending on the site. The costs of control-box systems are significant because the secure integration and maintenance of safe and stable process operations is critical.

Based on the TCOO and the 50% or 100% adoption scenarios discussed in Section 7.1, the potential European market size for industrial hybrid heating in 2030 and 2050 is shown in Figure 51.

Figure 51. Potential European market size for industrial hybrid heating, in mEUR



8.6 Technical assessment of industrial hybrid heating

Three technical aspects of the business cases were assessed: flexibility response time to the trigger, or signal, from the TSO or DSO; availability throughout the day and year; and resilience to system instability (towards frequency variation, for example)[148].

Flexibility response time to trigger, or signal, from the TSO or DSO. Industrial hybrid heating systems are highly suited for intra- and interday flexibility due to ramp rates and availability, and they are highly suited for congestion management assuming spatial distribution of industrial capacity beyond European industry clusters. This flexibility is also supported by short or moderately short response times.

Availability throughout the day and year. Industrial hybrid heating systems have nearly 100% availability throughout the day and year if applied to 24/7 processes, as shown in Figure 52. This availability contributes to a robust flexibility capacity that is able to respond to intra- and interday flexibility and congestion-management triggers.

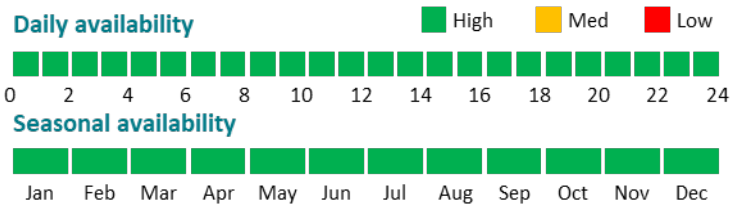
Resilience to system instability. Industrial demand-side response has a typical load-reduction-rate range of 20% to 100% ramp up or down per minute – significantly slower than battery-stored

[147] Abdallas Chikri, "Hybrid boiler systems in the Dutch industry: A techno-economic analysis"; and Kerttu, "Evaluation of electric and hybrid steam generation for a chemical plant."

[148] Content in this section is sourced in part from Marsidi/TNO-ECN, "Electrical industrial boiler"; Occo Roelofsen et al., "Plugging in: What electrification can do for industry," McKinsey & Company, May 2020, https://www.mckinsey.com/industries/electric-power-and-natural-gas/our-insights/plugging-in-what-electrification-can-do-for-industry;

capacity, for example. However, other than load reduction, industrial hybrid heating systems have no ability to contribute to frequency stabilisation.

Figure 52. Availability of flexibility from industrial hybrid heating throughout the day and year



Overall, analysis suggests few technical challenges. Half of existing industrial heat-generation capacity can be electrified for hybrid heating systems[149], and significant flexibility potential for intra- and interday and congestion-management services exist, with high ramp rates of electric systems and near 100% availability due to their hybrid nature.

8.7 Technical infrastructure required for industrial hybrid heating

The technical infrastructure required to implement this business case can be divided into three categories: analog, digital, and analytics.

Analog. First, from an analog perspective, upgrading the grid connections may be required. The complexity and cost of grid-connection upgrades depends on TSO and DSO pricing and the proximity of the TSO grid, if applicable.

Digital. On a digital level, integrating these systems into daily operations from process-optimisation and O&M perspectives is required. IT systems must be integrated, and robust cybersecurity must be instituted to ensure process stability even as the system is connected to more and more outside triggers. Because congestion-services system integration requires secure authorisation of TSO/DSO triggers, TSO/DSO stability services integration is also required. In addition, setting up or integrating trading systems is required, including (1) analytical integration to external capacity and power markets, (2) integration to internal demand and price-forecasting analytics tools, and (3) price spread forecasting to effectively integrate with operations for optimal scheduling of maintenance activities on both electric and nonelectric heating systems.

Analytics. It is possible that industrial operators will experience moderate technical infrastructure challenges to deliver industrial flexibility from hybrid heating systems at scale. Secure integration of power market and TSO/DSO triggers is critical for process safety. New analytics capabilities will be required by industrial operators to effectively integrate heat-source-switching models to operations and maintenance activities.

8.8 Industrial hybrid heating risk considerations

Potential risks could be experienced in relation to insurance coverage, cybersecurity, industry end-user acceptance and gamification potential. Most of these risks are moderate, and will need significant resolution effort:

Insurance coverage. Financing for industrial energy innovation is subject to high interest rates. Electrification increases financial risk as a consequence of power-price variability, with the high interest rates reported in at least one study[150]. Therefore, financial risk coverage could be considered, for example, by providing insurance for risks that are out of the control of operators.

Cybersecurity. A common EU strategy to establish reliable IoT communications for the energy system might lead to significant additional work for operators and hamper effective cybersecurity measures. The 2019 European Commission report *Demand Side Flexibility* identified perceived barriers and proposed recommendations that could arise from the increasing number of devices connected to the energy system in residential, commercial and industrial applications[151].

Industry end-user acceptance. The main drivers of this business case are uncertainty around future price developments (for example, in regards to power, fuel and CO_2 tax), the high cost of grid connection, payback times longer than the industry standard of two to three years and energy taxes in some countries that currently favour fossil fuels. The risk involved in this case is from the high cost of increased grid capacity and connection (which reflects a lack of financial incentive from the TSO or DSO to stimulate flexibility growth) and from the general lack of knowledge and information in the process industry about the technical possibilities (as there is a perception that high-temperature heat pump technology is unreliable or unproven)[152].

The main low risk, which can be resolved, falls under the category of gamification potential. If electricity pricing and capacity markets move to a location-based model, transparency regarding congestion-management compensation, electricity pricing and other issues becomes critical to minimise the possibility of market manipulation.

Moderate challenges exist in the areas of baseload and flexibility. The main risks to address are existing bias towards fossil fuels and lack of knowledge regarding the opportunity.

[150] Berenschot, *Electrification in the Dutch Process Industry: In-depth Study of Promising Transition Pathways and Innovation Opportunities for Electrification in the Dutch Process Industry*, February 2017, 10, https://blueterra.nl/wp-content/uploads/2018/03/Electrification-in-the-Dutch-process-industry-final-report.pdf.

[151] European Smart Grids Task Force, *Demand Side Flexibility*.

[152] Berenschot, *Electrification in the Dutch Process Industry.*

9 Business case: Residential heat pumps

Residential heat demand represents a significant share of overall energy consumption. Heat pumps can contribute to Fit for 55 and the Green Deal in two ways: by aiding decarbonisation through the electrification of heat generation, and by helping to balance the power grid through adding power flexibility.

This business case focuses on the flexibility provided by shifting heat demand and the related power load handled by residential heat pumps. Four residential building types in four European locations were modelled, taking into account climate zones, daily mean temperatures from 2010 (as one of the coldest years in the past 30 years) and various refurbishment standards to reduce demand and increase insulation capacities, or U-values.

The buildings' thermal mass is considered thermal storage, and it is assumed that all applications can be used in a flexible way. Adding water-based thermal storage where possible could increase the flexibility potential, depending on the size of the storage and the heat pump capacity.

Based on the diffusion of residential heat pumps, the final energy demand is assessed and used to estimate the potential for the adoption of this business case by 2050. The estimation uses modelled scenarios for the European Union from the EU-funded Efficiency First project[153]. Analysis suggests a 50% reduction in final energy demand by 2050 – from 1,531 terawatt hours in 2017 to 757 terawatt hours in 2050 – in the European Union using the following parameters:

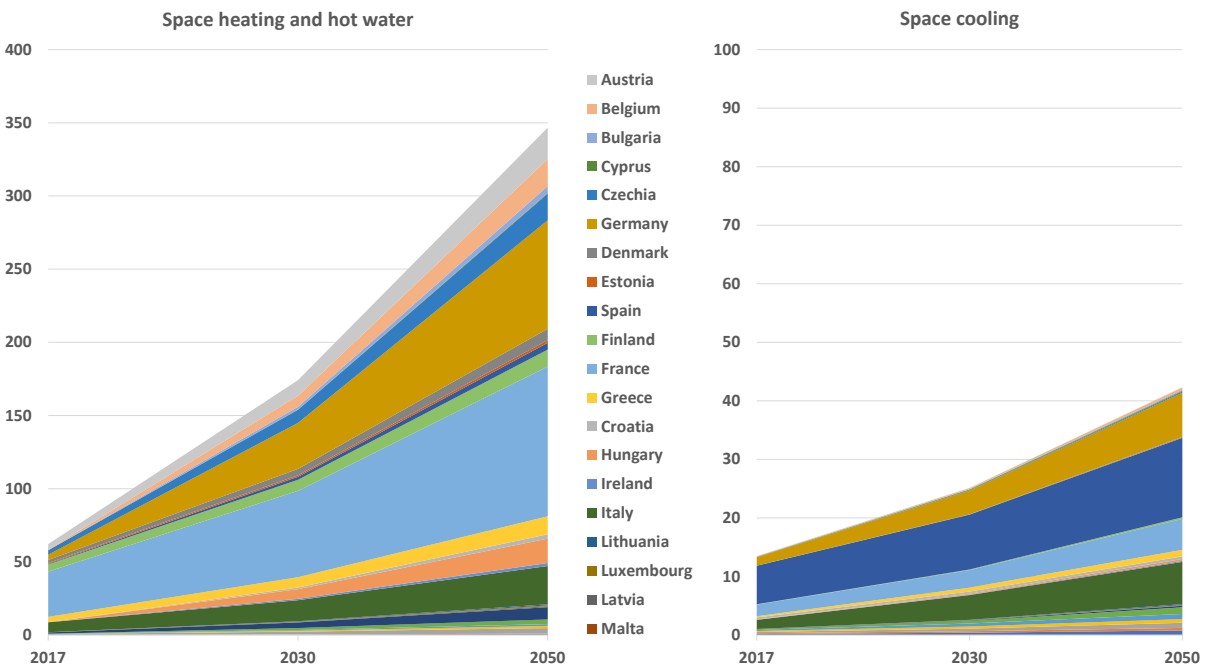
- residential heat pump share of the final energy demand increases from 4.1% (63 terawatt hours) in 2017 to 45.8% (347 terawatt hours) in 2050
- residential space final energy demand for cooling increases from 13.6 terawatt hours in 2017 to 42.3 terawatt hours in 2050
- targets set for the European Commission's renovation wave – to double the current average annual energy refurbishment rate of 1% by 2030 – are considered[154]
- electricity demand is calculated using the average coefficient of performance (COP) of 3.

Heat pumps' share of the space heating and hot-water demand in the residential sector is expected to grow in all EU member countries by a factor of 5.5 from 2017 to 2050, with the largest markets in absolute terms to be found in France and Germany. The final energy demand for space cooling is expected to grow in all countries, particularly in Italy and Spain, which in 2050 will constitute more than half of the space cooling demand.

[153] Energy Efficiency First, https://enefirst.eu/; and "Making Energy Efficiency First principle operational."

[154] European Commission, *A Renovation Wave for Europe – Greening Our Buildings, Creating Jobs, Improving Lives.*

Figure 53. Heat pump energy demand for space heating and hot water (at left) and for space cooling (at right) in residential buildings, in terawatt hours thermal



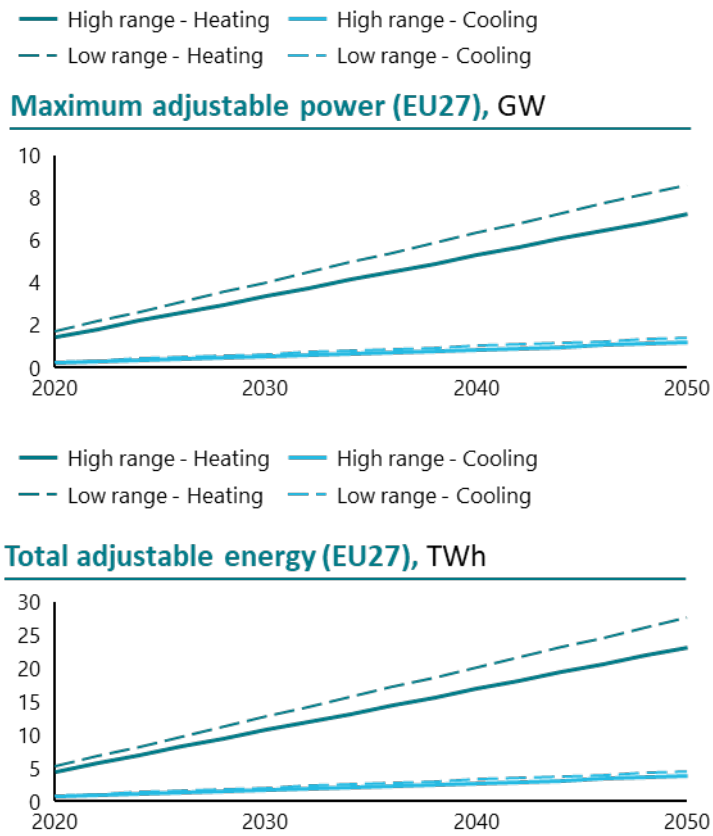
The residential heat pumps business case was analysed much the way building energy management systems, discussed in Chapter 7, were analysed.

For the estimation of the overall residential heat pump flexibility potential by 2030 and 2050, the energy demand of heat pumps for space heating, cooling and hot water were considered. The buildings' thermal mass is considered thermal storage, with flexibility based on the time required to heat or cool the building by 1 °C, from 20° to 19°. If the cooling time is more than two hours in each of the three six-hour flexibility blocks per day, the maximum flexibility time is six hours a day; if it is lower than two hours, the maximum flexibility time is three hours per day (or one hour in each of the three flexibility blocks). On average, between 2000 and 2020, there were 3,065 average annual heating degree days – that is, days in which the outside air temperature was lower than the reference temperature of 20 °C multiplied by the temperature delta to 20 °C – per year in the European Union and 90 cooling degree days, in which the temperature outside was higher than 20 °C. The calculated resulting average full load is equivalent to 1,113 hours annually.

9.1 Potential time frame for residential heat pumps impact

Between 17.6% and 35.3% of the final energy demand is identified as having flexibility potential depending on the type of building, U-values and climate zone. The resulting maximum adjustable energy in 2050 varies between 26 and 32 terawatt hours, which results in maximum adjustable power between 8 and 10 gigawatts, as shown in Figure 54.

Figure 54. Impact of residential heat pump flexibility on the European energy system



Analysis suggests few challenges in linking flexibility to residential heat pumps by 2050. It is already a market standard that new heat pumps be Wi-Fi compatible and capable of remote control, but smart electricity meters and additional adjustments to the house's electrical system are still necessary. Because the deployment of smart meters is ongoing, until 2050 the flexibility potential of residential heat pumps will likely be through aggregators or through direct contracts between households and DSOs.

9.2 Market overview for residential heat pumps

The competitive landscape for flexibility from residential heat pumps is driven by technology providers and utilities[155]. Electrical systems are operated by large, typically national utilities with their own TSOs and DSOs, and the utilities/DSO landscape varies substantially across Europe. Germany, for example, has a few large DSOs and many small, local ones; the Netherlands has a mix of DSOs, with the three largest accounting for more than 60% of distributed power; in Ireland there is only one DSO, while France's dominant DSO handles more than 80% of distributed power.

The market is divided based on the type of heat pump (air-to-air, water or geothermal source) and its application (commercial, residential or industrial). Air-to-air heat pumps hold the largest market share and are expected to retain this dominance. Table 20 shows key stakeholders, including well-established market players like Carrier and Bosch, as well as new market entrants (mostly developers

[155] Zachary E. Lee et al., "Providing grid services with heat pumps: A review," ASME Journal of Engineering for Sustainable Buildings and Cities 1, no. 1, February 2020, https://doi.org/10.1115/1.4045819.

and facility-management companies). Flexibility rates for heat pumps are slowly appearing in pilot projects, but there is still no market for them per se, so market share is undetermined.

Table 20. Key stakeholders for flexibility provision from heat pumps

Company	HQ location
Utilities, DSO and TSO	
EDF	France
EnBW	Germany
Enel	Italy
E.ON Group	Germany
Iberdrola	Spain
Ørsted	Denmark
TenneT	Netherlands
Manufacturers	
Bosch	Germany
Carrier	United States
Modine Manufacturing	United States
Systemair	Sweden
Viessmann	Germany

Technology providers and TSOs have begun collaborating in recent years on pilots using heat pumps with grid services. For example:

In 2021, Netherlands-owned TenneT, which is Germany's largest TSO, and the manufacturer Viessmann began working on a pilot project called ViFlex, which uses an app to synchronise Viessmann heat pumps with TenneT's requirements for congestion management.[156]

From 2017 to 2020 the German utility E.ON and five other regional players worked with more than a dozen partners to investigate flexibility interactions with the distribution grid after equipping 60 households with solar panels, storage heaters, heat pumps, smart meters and connected control devices. The technology, called the Smart Grid Hub, allows DSOs to connect directly to household smart meters, giving them more control over flexibility.[157]

The German energy company EnBW's Flexibler Wärmestrom project installed control boxes in 150 houses to provide demand-side management. The project employs price signals to create incentives for customers to use heating systems when there is an overproduction of renewable electricity.

[156] "Viessman and TenneT launch first project for smart use of heat and electricity," News Innovation Project, news release, TenneT, December 16, 2020, https://www.tennet.eu/news/detail/viessmann-and-tennet-launch-first-project-for-smart-use-of-heat-and-electricity/.

[157] "E.ON to participate in European smart grid project InterFlex," news release, E.ON, January 26, 2017, https://www.eon.com/en/about-us/media/press-release/2017/eon-to-participate-in-european-smart-grid-project-interflex.html; and InterFlex, *InterFlex Investigates the Use of Local Flexibilities to Relieve Distribution Grid Constraints*, project summary January 2017–December 2019, https://interflex-h2020.com/wp-content/uploads/2019/11/Interflex-Summary-report-2017-2019.pdf.

Analysis suggests few challenges in the heat pump flexibility market because the technology is mature and new heat pumps must be Wi-Fi enabled. In addition, several promising projects could accelerate the market uptake.

9.3 Stakeholder mapping for residential heat pumps

Stakeholders for this business case include society, government and business.

Society. Heat pumps reduce households' operating costs, allow for renewable energy integration, and, by providing flexibility, can be an additional source of revenue after an initial upfront cost.

Government. Heat pumps are a key part of the EU's green agenda because they can achieve ambitious CO_2 reduction targets. In addition, the development of new competitive flexibility options supports the European Union's strategy for energy-system integration. Policy support is required in new flexibility guidelines, better integration of heat pumps in electricity markets and investment in digital infrastructure. To avoid adverse impacts, it is important to keep heating infrastructure relatively simple.

In addition, national governments can increase grid flexibility by requiring that heat pumps be equipped with remote control, which drives grid stability and adoption of renewables and creates additional revenue. Governments should work out incentives for heat pumps as part of their decarbonisation strategy.

Business. The market holds great potential for heat pump manufacturers, and industries could also act as remote operators of digitally connected heat pumps, allowing heating technology providers to benefit from new business models. Manufactures should work to establish new communication and connectivity protocols to couple boilers, solar panels and other appliances with heat pumps. The focus on system flexibility will create additional requirements for heat pump technology, and strategies must be developed to secure and monetise heat-pump data.

Analysis suggests a medium level of challenges in stakeholder mapping. Stakeholders need more collaboration in terms of market commercialisation of innovative heat pumps, and policy barriers include inefficient market design and few incentives for flexibility. Today, grid operators are the main stakeholders driving the development of an EU flexibility market. To avoid adverse impacts, it is important to keep heating infrastructure relatively simple.

Integrating heat pumps into electricity markets and ancillary services can support renewable integration and increased grid flexibility, but if current regulatory incentives are insufficient, adverse effects could result. New flexibility or service models for residential flexibility management could improve grid efficiency. The cost of grid access should be reduced, and complicated market requirements should be avoided.

9.4 Innovation assessment of residential heat pumps

This section is a qualitative assessment of the innovation position of the European Union based on expert interviews and literature review.

9.4.1 European innovation position of residential heat pumps

The following aspects were taken into account while assessing innovation in Europe:

Market position of European firms. European firms have a strong market position, as most heat pumps installed in the European Union are manufactured in Europe. Major suppliers and manufacturers are Systemair, Danfoss and Modine Manufacturing Company, and the top three markets are France, Norway and Italy.

Share of European firms in the supplier and customer network. Nearly 15 million buildings in Europe, or around 6% of the 244 million residential units, use heat pumps[158].

Level of innovation in the European Union. The sector supports various high-level technological innovations, such as solar thermal collectors with zero-electricity heat pumps, and novel business models, including heating-as-a-service, which integrates various stakeholders including homeowners[159]. In addition, EU Horizon research projects have supported the development of innovative heat pump technologies[160].

Enabling environments (research institutes, universities, think tanks). Research institutes, universities and companies are working in collaboration to develop sustainable and cost-effective heat pump technologies[161]. Collaborators include Politecnico di Milano, Aalborg University, the Technical University of Denmark, the European Heat Pump Association, the Federation of European Heating, Ventilation and Air Conditioning Associations, and the European Technology and Innovation Platform on Renewable Heating and Cooling.

9.4.2 Spillover effects of residential heat pumps

The following indirect benefits could emerge from innovation in residential heat pumps:

Reusability of infrastructure, data and research results. Aspects of this business case are moderately transferable to upcoming sectors like hydrogen-based heating infrastructure and advanced thermal storage[162]. Data and pilot results can help to develop new energy services and customer-centric technologies.

Transferability to other industries. Heat pumps can cover a wide range of temperatures, which means they can be used in other temperature-dependent sectors such as agriculture and food production[163]. The cost of heat pumps is the major factor in this context.

Few challenges to this business case are expected. Air source, ground source and water source heat pumps dominate the current market, which is very mature and ready to adopt innovative technologies.

9.5 Economic assessment of residential heat pumps

Flexibility from heat pumps generates revenue via electricity and ancillary services markets. End users, heat pump manufacturers, energy providers and TSO/DSOs are the main stakeholders, as shown in Figure 55.

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[158] European Heat Pump Association (EHPA), "Market report 2021," https://www.ehpa.org/market-data/market-report-2021/.

[159] "Heizung mieten leicht gemacht – mit Viessmann Wärme Viessmann,"

[160] RHC Projects, "Projects on renewable heating and cooling," https://www.rhc-platform.org/projects/; RHC Projects, "Solar thermal collectors with a ZERO electricity heat pump & energy storage for sustainable heating and cooling," https://www.rhc-platform.org/project/solar-thermal-collectors-with-a-zero-electricity-heat-pump-energy-storage-for-sustainable-heating-and-cooling/; and RHC Projects, "THERMOS," https://www.rhc-platform.org/project/thermos/.

[161] Costanza Saletti, Mirko Morini, and Agostino Gambarotta, "The status of research and innovation on heating and cooling networks as smart energy systems within Horizon 2020, "Energies 13, no. 1, June 3, 2020, https://www.mdpi.com/1996-1073/13/11/2835.

[162] Rafat Hirmiz et al., "Performance of heat pump integrated phase change material thermal storage for electric load shifting in building demand side management," *Energy and Buildings* 190, May 1, 2019, https://www.sciencedirect.com/science/article/abs/pii/S0378778818333115.

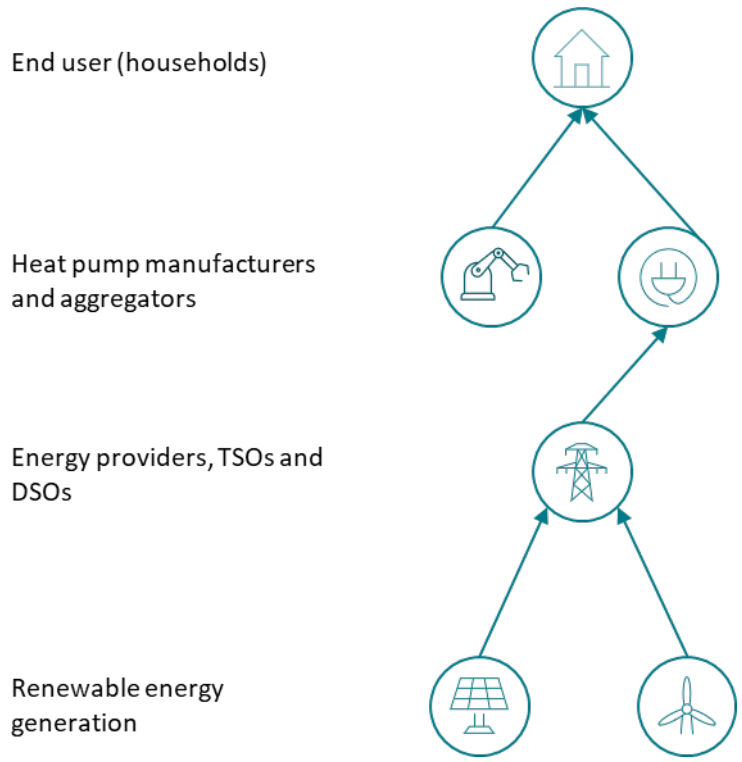
[163] Sachin V. Jangam, Arun S. Mujumdar, and Benu Adhikari, "Drying: Physical and structural changes," in *Encyclopedia of Food and Health*, eds. Benjamin Caballero, Paul M. Finglas, and Fidel Toldrá, Academic Press, 2016, https://www.sciencedirect.com/science/article/pii/B9780123849472002415.

The main concerns of end users (households), comfort and reliability, should be considered in this business case. Lower consumption bills or extra revenue streams are also key customer incentives.

Smart heat supply and demand shift are main revenue streams for aggregators and can provide additional revenue for heat pump manufacturers. Technical parameters, system dimensioning (consumption profiles, buffer volume, electrified heating capacity and so on) and economic conditions, especially price spreads, define viability and the profitability of flexibility. Leveraging aggregate consumption data can be a data-driven business model for both, potentially providing additional revenue streams.

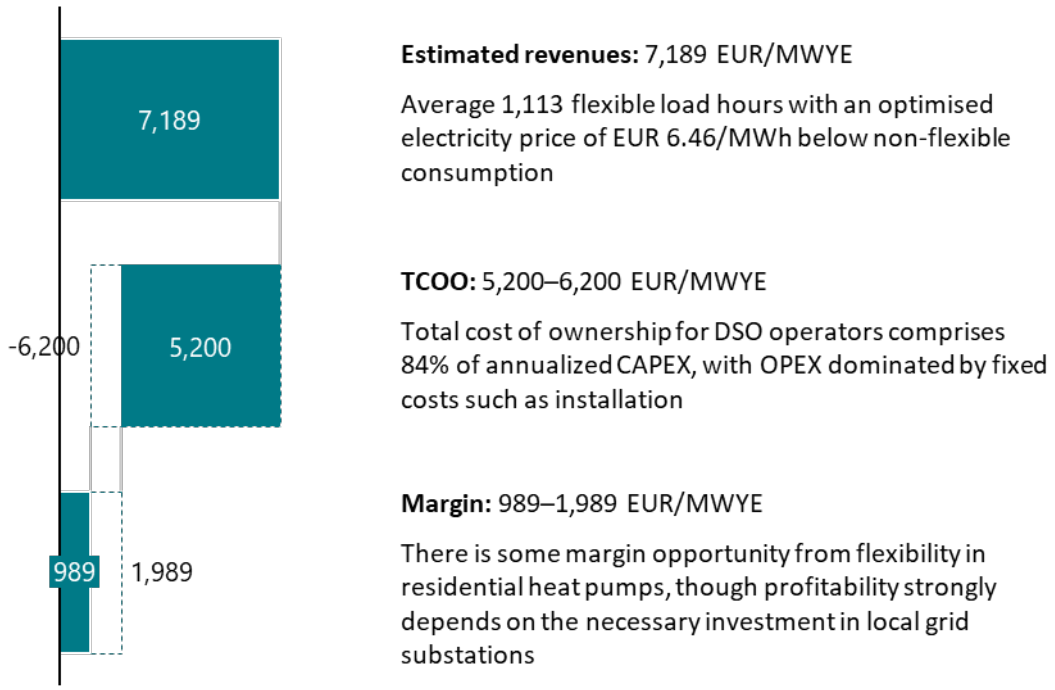
TSOs, DSOs and energy providers can incentivise aggregators and end users with variable tariffs and direct flexibility payments, in turn benefiting from electricity-market price spreads and additional flexibility for system operation and congestion management. Heat pump flexibility requires some additional investment in smart-grid infrastructure.

Figure 55. Power and energy flow for the residential heat pumps business case



Estimations of revenues and costs indicate that this business case can be profitable, but the cost of upgrading substations and local grids has a large impact on financial results. Revenue generation is assessed mainly via purchasing electricity at lower costs.

Figure 56. Revenue and total cost of ownership for residential heat pumps, EUR/MW



Analysis indicates low to medium challenges in monetising power-price spreads from which heat pump flexibility can benefit. This is reflected in a significant projected margin, though it strongly depends on the type of connection between heat pumps and electricity markets, communication between heat pumps and the TSO/DSO, the necessary infrastructural investments in the local grid substations and changes in fiscal and non-fiscal charges.

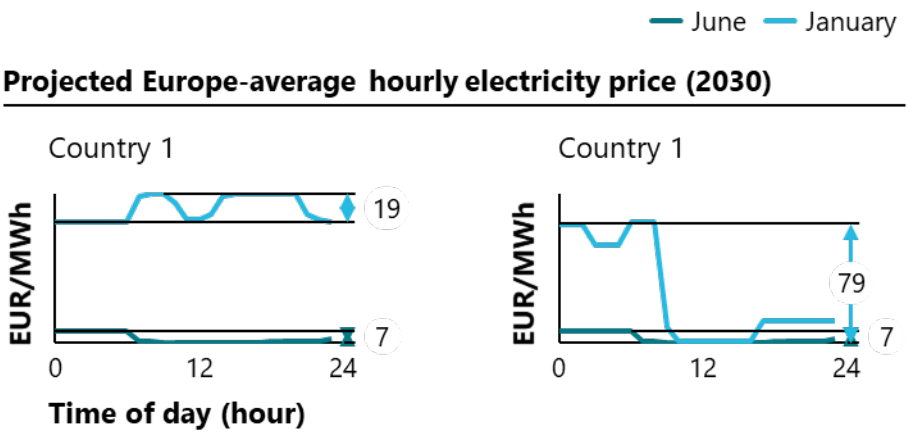
9.5.1 Residential heat pump revenue

Revenues are generated from purchasing electricity for heating at times of lowest power prices and providing demand-response ancillary services in the case of grid congestion. The calculation of revenues considers wholesale markets only. Estimations follow the approach for BEMS systems for commercial buildings, excluding the flexibility offered by the ventilation system, which apart from some new construction is not available in the residential sector. The flexible heat pump load is between 18% and 35% of the final energy demand for space heating, with cooling and hot water depending on the type of building, refurbishment standards and location.

Based on this assumption, an average of EUR 6.46 per megawatt hour can be saved, resulting in an estimated revenue of EUR 7,189 per megawatt-year.

The spread between the highest and lowest prices can vary significantly depending on the share of solar energy and the rate at which transmission infrastructure is built out. Figure 57 shows a hypothetical same-day spread in two countries.

Figure 57. Price spread for two hypothetical countries on days in June and January for the residential heat pumps business case



The revenue calculation is uncertain due to the difficulty of accurately predicting power prices. Only revenues from electricity markets are considered, and interactions among business cases on the electricity market prices are not taken into account.

9.5.2 Total cost of ownership for residential heat pumps

Hardware and software are the main upfront costs of this business case. It is assumed that control boxes that react to external triggers are the only hardware required, given that new heat pumps are already Wi-Fi enabled.

Other assumptions include an equipment lifetime of 20 years, 1,500 to 4,000 operating hours per year and an average heat pump electric capacity of 10 kilowatts.

Local smart-grid substations and smart meters are excluded from the hardware costs as they are installed independent of this use case and the costs are shared among business cases. The investment in the smart grid to accommodate future needs – including more distributed electricity generation, electric vehicles and charging infrastructure – is ongoing.

Table 21. Cost of residential heat pump flexibility (2021)

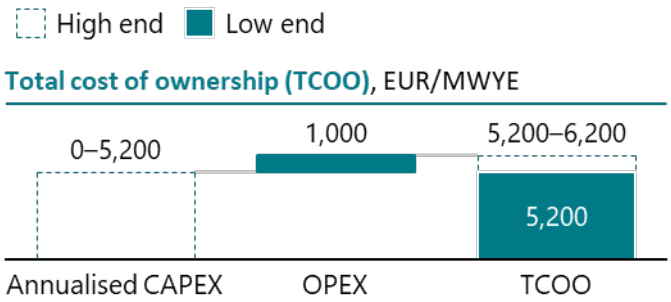
Capital expenses (CAPEX)	Cost range		Unit
	Minimum	Maximum	
Hardware: Control box (based on EUR 0 to EUR 850and 10 kilowatt capacity per installation	0	85,000	EUR/MW
Software: Network connection (based on EUR 0 to EUR 170 and 10 kilowatt capacity per installation)	0	17,000	EUR/MW

No OPEX costs are considered because the entire process is automated and no additional personnel cost or other operational costs are required to provide heat-pump flexibility.

As shown in Figure 58, based on the assumptions for capital expenses, the total cost of ownership is estimated to be between EUR 5,200 and EUR 6,200 per megawatt year. Because control boxes

are mature and established technologies, we expect limited variability in TCOO, and we have not defined price scenarios.

Figure 58. Total cost of ownership for BEMS flexibility provision, EUR/MWYE



9.6 Technical assessment of residential heat pumps

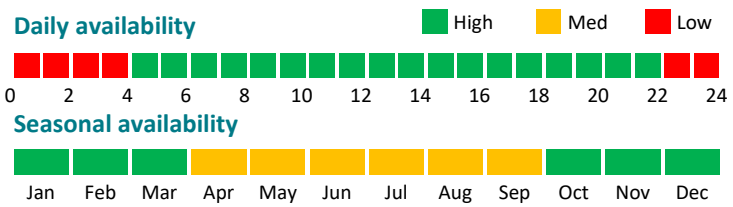
Three technical aspects of the business cases were assessed: flexibility response time to the trigger, or signal, from the TSO or DSO; availability throughout the day and year; and resilience to system instability (towards frequency variation, for example).

Heat pumps are highly suitable for providing flexibility. They can be switched off immediately, and they fully ramp up in 30 seconds, providing excellent response time to DSO triggers. If the building mass is used as thermal storage, the available load-shifting potentials are highly dependent on the outside temperature.

Heat pumps also provide high availability throughout the day and year, as shown in Figure 59. Availability is driven by user heat demand and is higher in winter and during the day. Adding thermal storage capacity, if technically feasible, can provide additional flexibility for several hours, which would increase overnight availability.

Power flexibility is lower in summer because of lower heat demand, though that could be offset by high demand for cooling. Actual availability strongly depends on system dimensions, including thermal storage size, domestic hot water supply, climate zone, building standards and so forth.

Figure 59. Availability of flexibility from residential heat pumps throughout the day and year



Heat pumps can positively contribute to system stability because they can provide intra- and interday flexibility and can adapt to support an optimised power flow, which is used to determine the best power-plant operating levels, leading to lower electricity production costs. Depending on the thermal storage availability and control strategy, the storage can be used to provide positive and negative control reserve in the case of frequency deviations.

Overall, analysis suggests few challenges in the technical aspects of leveraging energy flexibility from residential heat pumps.

9.7 Technical infrastructure required for residential heat pumps

If the heat pump is connected to the Wi-Fi network and can be accessed by aggregators or directly by the TSO/DSO, no additional physical grid integration is necessary. Otherwise, a control box, smart meter and local smart-grid substation are required.

If heat pumps provide flexibility to grid operators, DSO integration into their daily operation system is needed. Integration into congestion management and ancillary service systems requires secure authorisation of TSO/DSO triggers and compatibility with the heat pump control system.

Robust cybersecurity is key to protecting customer data and ensuring safe TSO/DSO systems operation.

For heat pumps to participate in electricity markets, they must be integrated into trading systems. Demand and price forecasting should consider the planned operation of heat pumps and the available flexibility.

Analysis suggests low to medium challenges in the technical infrastructure requirements around integration with TSO/DSO stability services and cybersecure remote control of electrified heat demand. Depending on the connection between the heat pump and the TSO/DSO, additional infrastructure could be required both in the grid and at customer premises.

9.8 Residential heat pump risk considerations

The main risks in this use case are cybersecurity threats and, if standards and prequalification requirements are not harmonised across Europe, the regulatory framework. Analysis indicates moderate risks and the need for significant resolution efforts in the following areas:

Lack of customer knowledge. In the residential sector, customer awareness about the opportunities to engage in demand-side response is low[164]. Building residential customer knowledge requires a clear explanation of the products by installers and service providers.

Differing standards and prequalification requirements across Europe are a major regulatory risk. Efforts are needed to define unified standards for access and control of residential heat pumps so that they can react to TSO/DSO triggers.

The low risks, which can be resolved with minor efforts, are:

Market framework. Allocation of energy volumes, appropriate and transparent baselining methodology and fair remuneration levels are major issues that would allow for easier entry for new market participants[165].

Cybersecurity. Data privacy regulation is relevant because flexibility requires increased sharing of data. If customers don't trust in the equipment and fear cyberattacks, they may not participate in the flexibility market. Who gets access to the data? What data is public? Who can share the data? Who is responsible for it[166]? Providing a clear and standardised answer to these questions could increase customer trust.

[164] European Smart Grids Task Force Expert Group 3, *Demand Side Flexibility: Perceived Barriers and Proposed Recommendations*.

[165] Ibid.

[166] Niels Westera, "Ownership of district heating," presentation, Fourth International Conference on Smart Energy Systems and Fourth Generation District Heating, Aalborg, Denmark, November 13–14, 2018.

Cyberattacks on the electrified heating and cooling supply – perhaps directed explicitly against heat pumps – are a potential risk for the electric grid, though the risk is low because of market fragmentation and standards that might limit such attacks to selected local grid areas.

Public and user acceptance. Price and flexibility revenue transparency may be low due to a lack of clear information about the costs and benefits of the opportunities available. Because the system value of flexibility is still low in the building sector, until now there has not been a clear business case for residential customers[167]. This omission is expected to be rectified in the next few years with higher penetration of renewable electricity and a higher price for emission-trading system certificates; customer engagement should increase with the higher revenue stream.

Gamification potential. There is a minor risk for gamification and strategic bidding if flexibility from heat pumps by aggregators is not coordinated.

All risks appear manageable.

[167] Ibid.

10 Business case: management systems

Residential buildings represent 26% of final energy demand in the European Union – that is, the energy required by consumers for end use. Self-consumption, the increasing share of renewables and digitalisation of the built environment offer enormous opportunities for demand-side flexibility. Home energy management systems (HEMS) consisting of smart technologies, connectable appliances, sensors, and smart meters allow individual households to interact with the electricity grid and the energy market and optimise the operation of PV-battery systems. Because this report focuses on system flexibility and demand-response potential, this business case examines on the flexibility from home battery storage.

10.1 Potential time frame for HEMS impact

The uptake scenario for HEMS and the stationary batteries that allow households to store energy for later use is based on a 2016 CE Delft study that found "the role of energy consumers as active participants in the energy system is bound to expand" in Europe, with the main growth expected to be in rooftop PV systems, electric cars and residential heat pumps[168]. The study analysed stationary batteries for households, public entities and small enterprises, and for multiple use cases. (Batteries for energy collectives, or virtual power plants, are considered in Chapter 4.)

It is assumed that stationary batteries will continue to provide the main flexibility for HEMS systems. Additional flexibility from residential heating and cooling is covered in more depth in Chapter 6.

The following are key projections for 2050:

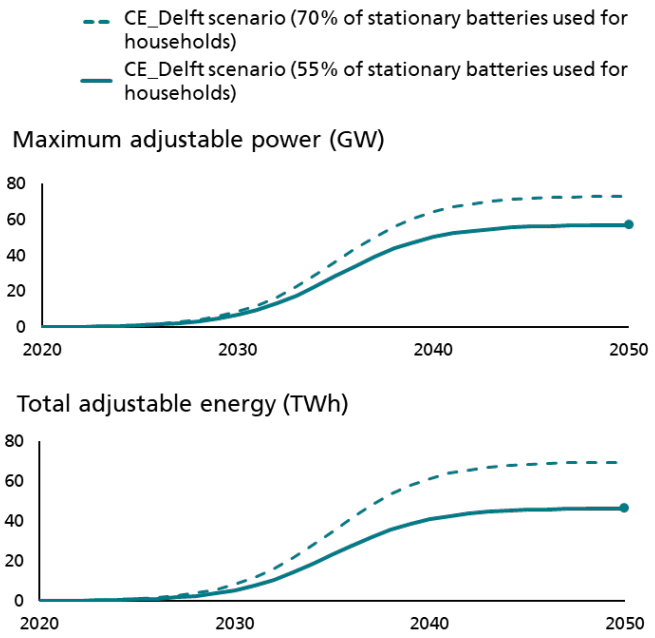
- Europe will be home to 187 million prosumers, 44 million of whom will have a stationary battery.
- Each prosumer will have an 8 kilowatt-hour battery (2.4 kilowatts at a C-rate of 0.3), which cycles fully about 300 times per year, based on a linked PV capacity of 3 kilowatt hour per kilowatt peak.
- As a result, all residential stationary batteries will have a maximum adjustable power of 103 gigawatts. If 45% of them, as estimated by CE Delft, participate in energy communities, the adjustable capacity of the remaining residential households will be 57 gigawatts, as shown in Figure 60[169].
- Around 55 percent of the total adjustable energy (86 of 155 terawatt hours) will be contributed by households that do not participate in the energy community[170].

[168] CE Delft, *The Potential of Energy Citizens in the European Union*, 16.3J00.75, September 2016, https://cedelft.eu/wp-content/uploads/sites/2/2021/04/CE_Delft_3J00_Potential_energy_citizens_EU_final.pdf.

[169] Ibid.

[170] Ibid. CE Delft analysed stationary batteries for households, public entities, and small enterprises and for multiple use cases.

Figure 60. Impact of HEMS on the European energy system by 2050



Analysis suggests moderate challenges to estimating the uptake and impact of HEMS and stationary batteries for self-consumption. The legal framework, grid access charges and RES support play a crucial role for diffusion of HEMS and batteries for self-consumption. Use of rooftop PV for electric cars and heat pumps is a strong driver for HEMS and battery adoption, but grid- and market-friendly use of flexibility will be dependent on user acceptance and cost benefits.

10.2 Market overview for HEMS

The market for residential energy storage systems is mature and fairly consolidated, with a mix of European and non-European players. It consists of battery manufacturers and home energy management service providers.

The 10 largest producers capture more than 90% of the European market for residential energy storage systems, as shown in Table 22. Market participants are a mix of traditional battery producers such as Varta and LG Chem, younger battery manufacturers like Tesla, and start-ups providing home storage solutions, including Sonnen, E3/DC and Enphase. Non-European players serve about 40% of the European market and increasingly offer software and platform products in addition to battery hardware[171]. For example, Sonnen, the market leader, offers SonnenBattery[172], a full suite of high-tech storage and home energy management products that disintermediate traditional energy providers.

[171] Pierre d'Halluin, Raffaele Rossi, and Michael Schmela, *European Market Outlook for Residential Battery Storage, 2020–2024*, SolarPower Europe, October 2020, https://resource-platform.eu/wp-content/uploads/files/statements/2820-SPE-EU-Residential-Market-Outlook-07-mr.pdf.

[172] "SonnenBatterie," Sonnen, https://sonnengroup.com/sonnenbatterie/.

Table 22. Home battery companies by market share

Company	Headquarters	European market share (%)
Sonnen	Germany	18%
LG Chem	South Korea	16%
BYD	China	14%
E3/DC	Germany	11%
SENEC	Germany	11%
VARTA	Germany	8.5%
Tesla Powerall	USA	3.6%
BMZ	Germany	3.4%
Enphase Energy	USAUS	3.2%
LG Electronics	South Korea	3.0%

10.3 Stakeholder mapping for HEMS

Stakeholders for this business case include society, governments, industry (specifically, battery manufacturers, suppliers and technology providers), and the power sector (specifically, TSOs and DSOs).

Society. Societal benefits come at the household level. In addition to promoting increased use of renewables and self-consumption, HEMS with integrated battery can provide households with an additional source of revenue through flexibility-market participation and peer-to-peer trading, though they do require an upfront investment.

Governments. Along with national European governments, the European Union is committed to developing a competitive flexibility market with the strong participation of home storage batteries. Indeed, a number of EU policies already have been employed to achieve flexibility from home storage, particularly as communicated in the smart readiness indicator (SRI), which was adopted by the European Commission in 2020 to "assess a building's ability to adapt to advanced technologies in terms of its performance capacity and energy flexibility"[173]. In fact, energy flexibility and storage are two of the key impact criteria of the smart readiness in buildings.

Large-scale adoption of decentralised home battery networks may result in raw-material supply risks in the European Union as demand for batteries increases[174]. The environmental impact from the materials used should not be overlooked, and circularity, or taking into account products' end-of-life when creating them, should be a priority.

[173] *Smart readiness indicator scheme* refers to a system of certification of smart readiness of buildings. See "Supplementing directive (EU) 2010/31/EU of the European Parliament and of the Council by establishing an optional common European Union scheme for rating the smart readiness of buildings," Commission Delegated Regulation (EU) 2020/2155, *Official Journal of the European Union*, October 14, 2020, https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32020R2155&from=en; the quote appears in "'Smart' buildings – smart readiness indicator (arrangements of rollout of scheme)," Europa, https://ec.europa.eu/info/law/better-regulation/have-your-say/initiatives/12365-%E2%80%98Smart%E2%80%99-buildings-smart-readiness-indicator-arrangements-for-rollout-of-scheme-_en.

[174] Press corner, Europa, https://ec.europa.eu/commission/presscorner/detail/en/QANDA_20_2311EU.

Despite existing EU policies, a viable implementation of home-battery flexibility requires new guidelines regarding the use of home storage systems, market design, investment in digital infrastructure, and guaranteed access to the flexibility market. Simultaneously, national governments should provide appropriate incentives for home battery storage, and remove barriers such as disproportionate fees for internal consumed electricity, the obligation to feed self-generated electricity to the energy system and inconsistent access to the grid[175].

Industry. Battery manufacturers have the opportunity to capture the market potential of self-consumption and flexibility, but robust cybersecurity controls must be incorporated to reduce risk. Furthermore, to cope with hazards like thermal runaway, which can cause the system to overheat, building-code-compatible home storage systems are recommended[176]. Interoperability and standardisation protocol for batteries are other major challenges for the battery manufactures and HEMS providers.

The Italian energy management firm Enerbrain has noted the lack of residential participation in the flexibility market and has recommended a new flexibility market design[177]. This and other business-model innovations, such as flexibility as a service, could play a vital role in engaging consumers and energy-related service providers.

Research institutes are experiencing increased demand for low-cost, smart, digital battery packs, which is driving the development of innovative batteries using emerging technologies; research is underway on printable and organic batteries, for example. A wide range of pilot projects should be commissioned to demonstrate the potential use of digital technologies in home-battery management.

Power sector. Grid operators could benefit from increased grid flexibility, frequency response and stabilisation. Improving the grid's economic potential may require new flexibility or a service model for residential battery flexibility management. The cost of distribution and transmission networks is a major pain point for grid operators, and complicated market restructuring by grid operators and national governments will be required to address this issue.

10.4 Innovation assessment of HEMS

This section is a qualitative assessment of the innovation position of the European Union based on expert interviews and literature review.

The European Union's favourable market for home energy storage should accelerate as the price of lithium-ion (Li-ion) batteries decreases and PV systems are increasingly adopted. Batteries are one of the main priorities of the European Strategic Energy Technology (SET) Plan, "a key stepping-stone to boost the transition towards a climate-neutral energy system through the development of

[175] Interreg Europe, "Renewable energy self-consumption," policy brief, September 2020, https://www.interregeurope.eu/fileadmin/user_upload/plp_uploads/policy_briefs/Energy_self-consumption Policy_brief_final.pdf; and Xavier Potau, Samuel Leistner, and George Morrison, *Battery Promoting Policies in Selected Member States*, Batstorm work package 5, European Commission C2/2015-410, ECOFYS Germany, July 2018, policy_analysis_-_battery_promoting_policies_in_selected_member_states.pdf.

[176] UK Office for Product Safety & Standards, *Domestic Battery Energy Storage Systems: A Review of Safety Risks*, BEIS research paper 2020/037, September 2020, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/923611/domestic-battery-energy-storage-systems.pdf.

[177] Enerbrain, https://www.enerbrain.com/. Enerbrain emphasizes a new flexibility market design that paves the way for individual household participation. The current market mechanisms leverage mainly energy flexibility from the industrial actors.

low-carbon technologies in a fast and cost-competitive way"[178], in part by making the European Union an appealing market for batteries and the use of electric vehicles.

European firms are well-positioned in the battery storage innovation landscape, and analysis suggests low risk for European innovation in the adoption of home batteries.

10.4.1 European innovation position of HEMS

The following aspects were taken into account while assessing innovation in Europe:

- *Market position of European firms.* Increasing self-consumption in buildings, favourable policies, and the proliferation of home solar power have created a unique opportunity for European firms. Germany is the largest market for European residential storage, followed by Italy and the United Kingdom. However, the battery market is primarily driven by non-EU firms, including South Korea's Samsung SDI and LG Chem, and BYD in China. EU firms, including Eaton, CrowdNett and SENEC, are primarily active in the operations and solution-providers segment.
- Share of European firms in the supplier and customer network. The home battery market in the European Union is expected to grow by 16% by 2024. Many European storage services and solutions are offered by small to medium enterprises, start-ups and established companies.
- Level of innovation in the European Union. A high level of innovation, particularly in lithium-ion, 3D-printable and organic batteries, has been reported by member states, and the European Commission is supporting various battery-innovation projects including BATMAN, which stands for lithium ion BATteries – Norwegian opportunities within sustainable end-of-life MANagement, reuse and new material streams[179]; BATTERY 2030+, which consists of six research projects "with the vision of inventing the sustainable batteries of the future"[180]; a thin-film flexible lithium-ion battery for use on wearable devices from an Israeli company called 3DBatteries Ltd.[181]; the Netherlands' SCORES, which "combines and optimises" energy generation, storage and consumption with grid supply[182]; the collaborative BATSTORM, which aims to identify and support R&D needs and market uptake[183]; and the European Commission's BRIDGE platform, which examines issues encountered in demonstration projects that "may constitute an obstacle to innovation[184].
- *Enabling environments (e.g. research institutes, universities, think tanks).* A well-established network of universities, laboratories, established companies and innovative start-ups is conducting research related to energy storage and demand-management technologies. A few leading examples pushing battery research to the new horizon in Europe are the Laboratory for Innovation in New Energy Technologies and Nanomaterials (LITEN), in Grenoble, France; Germany's Fraunhofer Institute for Chemical Technology, in Pfinztal, and the Münster

[178] European Commission, "Energy and the Green Deal," Europa, n.d., https://ec.europa.eu/energy/topics/technology-and-innovation/strategic-energy-technology-plan_en.

[179] "BATMAN," Eyde-Cluster, n.d., https://www.eydecluster.com/en/innovation/batman/; CORDIS, "Feasibility study of a high energy BATtery with novel Metallic lithium ANode," Europa, n.d., https://cordis.europa.eu/project/id/696326.

[180] "Sustainable batteries of the future," Battery 2030+, n.d., https://battery2030.eu/.

[181] "3DBattery µBattery innovative thin-film flexible Lithium-Ion battery manufacturing," Europa, n.d., https://cordis.europa.eu/project/id/817330/it.

[182] Scores Project, n.d., http://www.scores-project.eu/.

[183] Ecofys, "Battery-based energy storage roadmap: Stakeholder kick-off report," European Commission, 2015, https://ec.europa.eu/energy/sites/ener/files/documents/batstorm_stakeholderkick-off_workshopires_report.pdf.

[184] "Cooperation group of Smart Grid, Energy Storage, Islands and Digitalisation of H2020 projects," Bridge, n.d., https://www.h2020-bridge.eu/.

Electrochemical Energy Technology (MEET) at the University of Münster; TU Delft in the Netherlands; and Sweden's Uppsala University's centre of excellence in battery research.

10.4.2 Spillover effects of HEMS

The following indirect benefits could emerge from DERMS innovation:

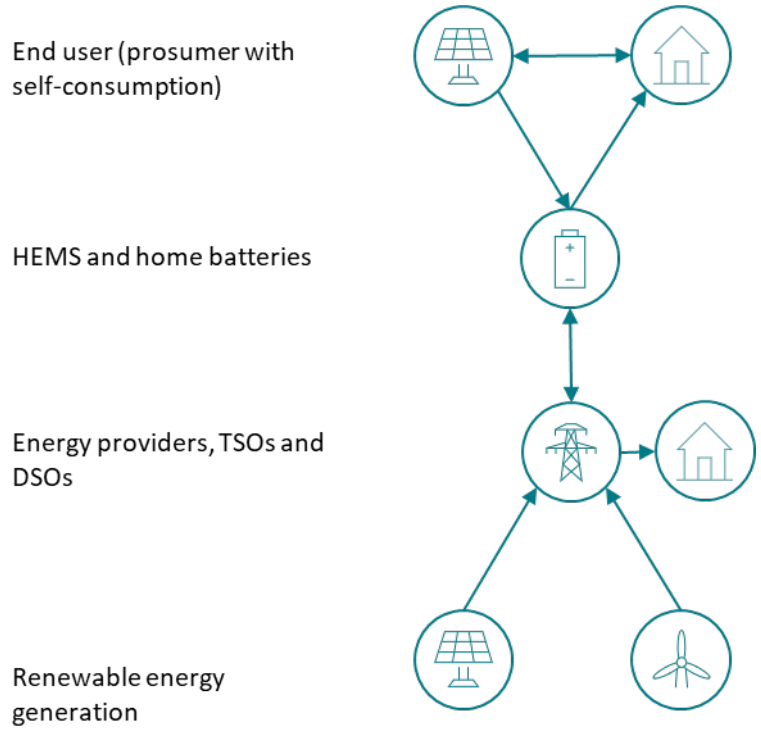
- *Reusability of infrastructure, data and research results.* Local electricity trading using blockchain technology, VPPs and battery packs are contemporary technologies that can leverage smart-home storage infrastructure and research results.
- *Transferability to other industries.* There is a high level of transferability in peer-to-peer energy trading between smart homes, neighbourhoods and communities. Another potential use could be to establish mini-grids in off-grid regions or communities.

10.5 Economic assessment of HEMS

This section discusses the main players associated with the HEMS business case – that is, those primarily expected to implement it – and explores its economic viability of the case for them. Figure 61 shows a schematic of the power and energy flow and the players relevant to this business case.

Presuming end-users typically generate power through on-site PV panels, store it in an on-site stationary battery and trade any surplus with the electricity grid, they can offer battery storage capacity for flexibility and grid services, and can optimise energy consumption at home via HEMS. Furthermore, HEMS, home batteries and smart meters are linked with the electricity market to help home systems provide flexibility from power generation, storage and demand-side applications. TSOs and DSOs are responsible for feeding surplus energy into the grid, which can be offloaded by significant self-consumption and HEMS generation.

Figure 61. Power and energy flow of the HEMS business case



HEMS and home battery use are highly dependent on regulatory frameworks, which could allow for providing households with relatively inexpensive, centrally generated green electricity. Cost is driven by battery capital expenditures, and although it is expected to fall, overall profitability is uncertain due to possible regulatory changes regarding self-generated versus grid-generated electricity and flexibility incentives for prosumers. Analysis indicates moderate challenges in the viability of this business case.

10.5.1 HEMS revenue

Figure 62 shows a high-level estimate of operating revenue in this business case. Based on our assumptions, the estimated revenue falls in the range of EUR 25,000 to EUR 82,500 per megawatt year. In this estimate, prosumer revenue, determined in part by taxes and fees and varying greatly across Europe, is a key driver.

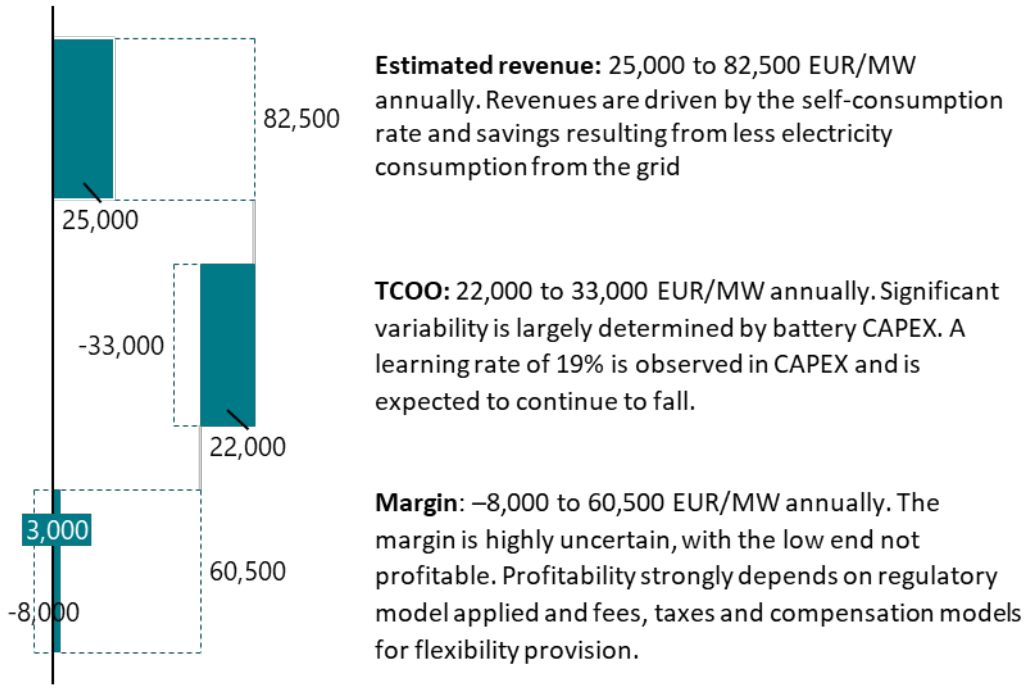
It is assumed that home batteries with PV systems can reduce a prosumer power bill by 10% to 30%. HEMS systems are needed to optimise operation of PV-battery systems and can contribute to further demand-side applications, such as large home appliances like washers and dryers. HEMS would also be connected to heat pumps, air-conditioning systems and electric cars (see other use cases for quantitative assessment).

The revenue estimate also includes the following parameters:

- Prosumers are assumed to have battery capacity of 8 kilowatt hours (2.4 kilowatt hours at a C-rate of 0.3)[185].
- The average power bill per prosumer is EUR 660 per year.
- The annual power bill reduction through self-consumption is 10% to 30%, depending on self-consumption rate.

[185] CE Delft, *The Potential of Energy Citizens in the European Union*.

Figure 62. Estimated HEMS operating margin



Analysis suggests moderate challenges in estimating revenues from HEMS and home batteries because of significant uncertainty in estimating underlying retail prices and fiscal charges pending self-consumption regulations – which may change in the future and vary from country to country.

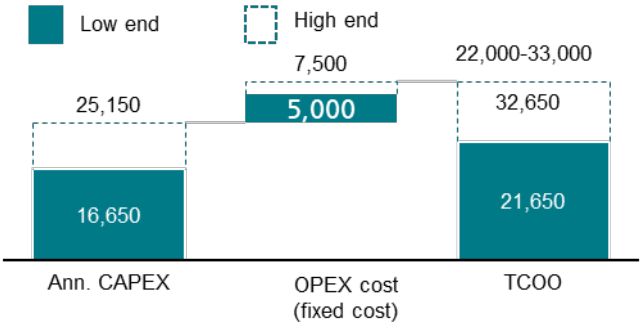
10.5.2 Total cost of ownership for HEMS

The cost of stationary batteries is assumed to be between EUR 333,000 and EUR 500,000 per megawatt (based on EUR 100,000 to EUR 150,000 per megawatt hour and a C-rate of 0.3 kilowatts per kilowatt hour[186]), depending on the batteries' composition. The main material combination is 34% lithium iron phosphate (LFP), 31% lithium nickel manganese cobalt oxide (NMC) and 25% lithium nickel cobalt aluminium oxide (NCA)[187]. Fixed operating costs account for 1.5% of original CAPEX cost. Figure 63 shows the total cost of ownership based on annualised CAPEX and OPEX.

[186] The C-rate has been defined as "a measure of the rate at which a battery is discharged relative to its maximum capacity." A C-rate of 1 means the battery will be discharged in one hour. See the Massachusetts Institute of Technology (US), MIT Electric Vehicle Team, "A guide to understanding battery specifications," December 2008, https://web.mit.edu/evt/summary_battery_specifications.pdf.

[187] David Roberts, "The many varieties of lithium-ion batteries battling for market share," Canary Media, April 21, 2021, https://www.canarymedia.com/articles/the-many-varieties-of-lithium-ion-batteries-battling-for-market-share/.

Figure 63. Total cost of ownership for HEMS, EUR/MWYE



The following additional parameters should be considered:

- Intense price competition is leading battery manufacturers to develop new chemistries and improved processes to reduce production costs. The learning rate, or the price decrease for every doubling of capacity, is 19%, which will bring the 2021 price of EUR 150 per kilowatt hour down[188].
- Cost for a HEMS system with a smart meter capable of handling 10 kilowatts is EUR 600 to EUR 1,000.
- Equipment lifetime is 20 years.
- Battery C-rate is 0.3 MW/MWh.
- Full load hours per year total 1,500[189].

The cost of flexibility in HEMS/home battery systems is driven by the cost of the battery itself. Battery prices are expected to continue to fall, reducing upfront costs and raising the potential for electricity cost savings and additional revenues, leading to greater adoption of home energy storage. Uncertainty around uptake remains because of competition in application areas such as ancillary services and electric vehicles that could also be used for power storage.

10.5.3 Technical assessment of HEMS

Three technical aspects of this business case were assessed: flexibility response time to the trigger, or signal, from the home battery or the TSO or DSO; availability throughout the day and year; and resilience to system stability.

Flexibility response time to the trigger, or signal, from the home battery or TSO or DSO. Home energy storage is normally used intraday, with availability limited by battery capacity; 8 kilowatt-hour batteries can provide power for only a limited time, usually eight to 10 hours, without recharging. Home batteries are highly flexible, and additional capacity could be available in the winter, when battery usage for PV self-consumption is lower.

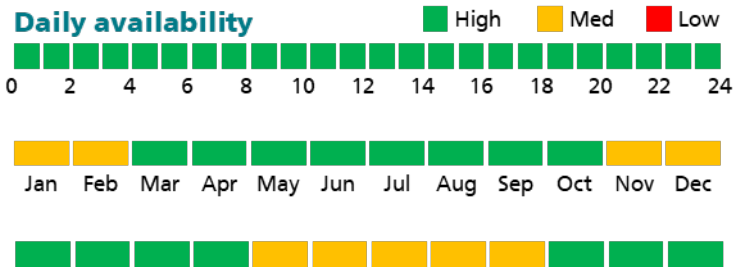
Availability throughout the day and year. Intra- and interday stability of batteries is high due to high ramp rates and good availability, see Figure 64. These factors also provide good congestion management, which is not cited as a main business case for home batteries because it requires local interaction with DSOs in real time, as opposed to virtual (location-independent) trading of battery

[188] Claire Curry, "Lithium-ion battery costs and market: Squeezed margins seek technology improvements and new business models," slide presentation, Bloomberg New Energy Finance, July 5, 2017, http://data.bloomberglp.com/bnef/sites/14/2017/07/BNEF-Lithium-ion-battery-costs-and-market.pdf.

[189] Roberts, "The many varieties of lithium-ion batteries."

capacity. Frequency stabilisation is highly suitable for frequency containment reserves, as shown by sonnenBattery, for example.

Figure 64. Availability of HEMS flexibility throughout the day and year



Resilience to system stability. Batteries beat other energy technologies in technical performance, and are expected to improve in terms of durability, degradation rate, energy density, cost and efficiency.

10.5.4 Technical infrastructure required for HEMS

The technical infrastructure of home batteries can be divided into three categories: analog, digital and integration with the grid network.

First, upgrading the grid connections may be required. Connecting stationary batteries to the grid is vital to setting up bidirectional communication, particularly with DSOs. Smart meters can sense energy market-signals and help home battery systems contribute to the flexibility market. The few challenges predominantly regard access to the TSO/DSO infrastructure and integrating secure advanced metering infrastructure.

To participate in flexibility market, HEMS systems require stationary batteries connected to renewable generation. Digital integration requires a secure ICT system to prevent cyberattacks and ensure customer data security; an advanced IoT sensor-grid infrastructure to interface monitoring (e.g. battery capacity, charge cycles and usage patterns) and control protocols; and a digital user interface to monitor the battery system's performance.

10.6 HEMS risk considerations

The main risks for HEMS are in regulation, cybersecurity, industry end-user acceptance and gamification potential. These risks are low and do not require complex resolution.

- *Regulatory*. Regulations affect the allocation of benefits between the grid and prosumers. To make the grid system profitable, regulatory policies must assure that grid and network access costs are fair.
- *Cybersecurity*. Home battery storage systems can be cyberattacked, and HEMS data can be misused.
- *Public and user acceptance*. HEMS combined with decentralised energy devices like rooftop solar and battery storage allows for self-consumption optimisation, so there is little risk the public will not accept it.
- *Gamification potential*. Feed-in tariffs, which pay small-scale energy producers above-market rates for what they deliver to the grid, and premiums on load shifting could encourage home battery storage on a large scale.

This analysis suggests few challenges in addressing the risks of home energy management systems. Regulatory aspects such as network and grid access can be resolved by addressing cost-reflective and non-discriminatory network charges. Greater efforts may be required to formulate the regulations, taxes and fee structures for battery storage and grid access.

11 Use case: Electric vehicle smart charging

Since the first mass-marketed electric vehicle (EV), was launched in 2010, sales of EVs have grown substantially worldwide. Although plug-in hybrid vehicles are still the biggest sellers, fully electric battery electric vehicles (BEVs) are becoming more popular since most can now go more than 200 miles on a full charge, and because renewable electricity can meet charging requirements, greenhouse gas emissions and the dependency on imported fossil fuels are being reduced.

Studies disagree about the speed and extent of EV diffusion in Europe, but there is wide consensus that electric vehicles will become the dominant technology for passenger cars in the next few decades, and therefore electricity demand from EVs will increase substantially. This can pose challenges, including increasing demand peaks and grid congestion, but because of EVs' long idle times, automated control and batteries that exceed daily mobility needs, charging can be controlled with modest effects on user comfort and convenience, so EVs also represent a vast potential source of demand-side flexibility, particularly beyond 2030. The overarching analysis in Chapter 13 shows that flexibility from EVs is among the largest contributors to overall potential, and vehicle to grid (V2G) specifically is the largest single business case in terms of flexibility capacity (in gigawatts).

This Chapter closely examines two business cases within the smart-charging use case:

Price-responsive charging: EVs adapt their load-shifting charging pattern based on a real-time or time-of-use price signal; by 2050 this adaptation is expected to provide 551 gigawatts of power in the European Union.

Self-consumption optimisation: EV charging targets the maximisation of household self-supply with a renewable electricity supply unit. By 2050, self-consumption optimisation is expected to provide the European Union with 17 gigawatts of power.

This Chapter covers unidirectional smart charging or V1G; bidirectional charging and discharging, or V2G, is covered in Chapter 12.

11.1 Market Overview for EV smart charging

This section aims to give an overview of companies that offer services or general infrastructure for V1G applications. Although our focus lies on the European market, non-European companies that are seen as pioneers in these fields are also listed.

A significant number of companies are providers of smart-charging infrastructure, and the number of companies offering V1G services, including software, is continually increasing. Though no complete view of market share for EV infrastructure or service providers in Europe is available, Table 23 lists some of the key players in the field.

Table 23. Smart-charging market

	Company	Headquarters
Operators of charging infrastructure		
	ABB	Switzerland
	Alfen	Netherlands
	Allego	Netherlands
	BP Chargemaster	UK
	Efacec	Portugal
	Enel X	Italy
	EVBox	Netherlands
	Ionity	Germany
	Shell Recharge Solutions (formerly New Motion)	Netherlands
Service providers		
	Bosch	Germany
	Driivez	Israel
	Greenflux	Netherlands
	Last Mile Solutions	Netherlands
	Octopus Energy	UK
	Siemens	Germany
	Virta	Finland

Germany is the only European country that makes smart charging a requirement for operators to receive financial support[190]. As a result, across Europe the vast majority of EV users currently do not apply smart charging. Considering public interest in charging infrastructure and the current growth of the EV market, this analysis projects low challenges in further growth of smart-charging infrastructure. In Germany, for example, once the current requirements are fully implemented, all charging stations should have smart charging capacity, which will likely increase adoption.

11.2 Stakeholder mapping for EV smart charging

Stakeholders for this use case include consumers, governments, energy-industry businesses and the environment. Impacts of the use of EVs as flexibility resources for these stakeholders are described below.

Consumers. Consumers, or owner-users of EVs, benefit from smart charging because it allows them to save charging costs by charging only at moments of lowest electricity cost. Potential downsides for consumers could include the possibility of increased battery degradation because of more charge/discharge cycles and the possibility that their car is less available for driving, because it will be charging incrementally at moments of lowest cost, requiring it to be stationary for longer

[190] Koen Noyens, "EV charging infrastructure incentives in Europe 2021," EVBox, December 14, 2020, updated September 30, 2021, https://blog.evbox.com/ev-charging-infrastructure-incentives-eu.

periods. Local citizens who do not own an EV are expected to experience neither a positive nor a negative impact.

Governments. National governments and municipalities could benefit from the widespread adoption of EVs because they reduce air pollution. No positive or negative impacts are expected with regard to smart charging per se, though municipalities could be considered enablers because they could set up their own public charging infrastructure or facilitate third-party activities by reducing administrative obligations and implementing attractive frameworks and other support instruments. National governments could also have a positive impact by lowering costs through efficient integration of renewables into the system[191].

Business. From a business perspective, energy retailers and aggregators can both benefit from optimised procurement when EVs charge at lower prices. System operators (TSOs and DSOs) may also see cost savings from deferred capital investments, as well as reduced grid constraints. However, price-responsive charging can also induce local grid constraints if it targets a central price signal that does not reflect the local grid situation, so grid charges should reflect local conditions.

Depending on their business model, charging-point operators (CPOs) could save directly by aggregating EVs' flexibility potential, or they could receive a fraction of EV users' savings in the form of transaction costs. CPOs could act as enablers by providing standardised communication interfaces for the hardware and software of various stakeholders.

Mobility service providers could benefit in the same ways CPOs could, but may have conflicting interests if mobility needs coincide with power system needs. Manufacturers of charging infrastructure can generate profits from consumers' interest in purchasing smart chargepoints.

Environment. Finally, the environment could benefit, as future power systems have high flexibility needs that can be satisfied in part by smart charging. EV flexibility integrates renewables into the power system, which can also lead to emission reductions and other positive impacts. However, in power systems with a high share of conventional power plants, the use of EV flexibility could also lead to a higher share of CO_2-intensive power plants, because the cheapest ways of making power require constant demand; therefore, if the residual load becomes more continuous, peak power plants with low CO_2-intensity (those that use natural gas, for example) would be replaced by higher-intensity plants that use less expensive hard coal or lignite. However, this effect is not expected in markets with a high share of renewables[192].

Well-designed smart charging does not appear to have significant negative impacts on any of these stakeholders. Incentives can be considered as a means for supporting smart charging.

11.3 Innovation assessment of EV smart charging

Research identified moderate overall challenges in the role of European innovation in the adoption of smart charging. European companies are strongly involved in pilot projects and building services and platforms, but for now are often dependent on hardware manufactured outside of Europe.

[191] Philipp Hanemann, Marika Behnert, and Thomas Bruckner, "Effects of electric vehicle charging strategies on the German power system," Applied Energy 203, October 2017, https://www.sciencedirect.com/science/article/abs/pii/S0306261917307924; and Wolf-Peter Schill and Clemens Gerbaulet, "Power system impacts of electric vehicles in Germany: Charging with coal or renewables?," Applied Energy 156, October 2015, https://www.sciencedirect.com/science/article/abs/pii/S0306261915008417.

[192] Schill and Gerbaulet, "Power system impacts of electric vehicles in Germany"; and Matthias Kühnbach et al., "Impact of electric vehicles: Will German households pay less for electricity?," Energy Strategy Reviews 32, November 2020.

Europe is currently experiencing strong market uptake of electric vehicles. As renewable energies are expanded and conventional power plants are phased out, the need for flexibility will likely increase[193], and EVs can help to address this need. Numerous research projects on smart charging and V2G are ongoing worldwide, including in Europe.

11.3.1 European innovation position

This section is a qualitative assessment of the innovation position of the European Union based on expert interviews and literature review.

Market position of European firms. Most EV manufacturers today are located outside Europe; European charging-infrastructure manufacturers, however, are well-positioned in the market. Examples include ABB, which is a front-runner, particularly for fast-charging stations[194]; Siemens; BP Chargemaster, which operates one of the largest EV-charging networks worldwide; EVBox; and Shell Recharge Solutions, which until November 2021 was called NewMotion. Europe is the second-largest market worldwide, after China, with 250,000 slow chargers and 38,000 fast chargers installed in 2020[195]. Market leaders in Europe include the Netherlands, Denmark, the United Kingdom and Germany[196].

Share of European firms in the supplier and customer network. Many European utilities – including aWATTar, E.ON and Energy Market Solutions in Germany; Shell in the Netherlands; Statkraft and Tibber in Norway; Wels Strom in Austria; Électricité de France; and Eesti Energia in Estonia – already offer a range of variable rates for EV charging, with further tariff structures emerging that will likely increasingly capture the dynamics of the grid and the power market, allowing for interaction between consuming EVs and grid operators.

Level of innovation in the European Union. Driven by national and EU funding, European companies, in collaboration with utilities, technology and hardware providers, and innovative research institutions, have started studying a broad range of topics, such as smart and bidirectional charging, grid integration and market participation. Examples include the Mobility House (Germany); Enel Energia, Nissan Italia and the Italian Institute of Technology (Italy); Alliander (Netherlands); Renault and Empresa de Electricidade da Madeira (Portugal); Northern Powergrid (UK); TU Delft (Netherlands); Cenex (UK); VTT (Finland); EIT Urban Mobility (located across Europe); and Smart Innovation Norway[197].

This analysis shows that moderate challenges may emerge for EV smart charging innovation in Europe because it is dependent on hardware manufacturing outside Europe.

11.3.2 Spillover effects of EV smart charging

The following indirect benefits from smart charging innovation could emerge:

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[193] Europe Beyond Coal, "Overview: National coal phase-out announcements in Europe," Status August 3, 2021, Overview-of-national-coal-phase-out-announcements-Europe-Beyond-Coal-3-August-2021.pdf.

[194] Frost & Sullivan, *Frost Radar™: Global Electric Vehicle Charging Infrastructure Market, 2020: A Benchmarking System to Spark Companies to Action – Innovation That Fuels New Deal Flow and Growth Pipelines*, November 2020, https://store.frost.com/frost-radartm-global-electric-vehicle-charging-infrastructure-market-2020.html.

[195] International Energy Agency (IEA), *Global EV Outlook 2021: Accelerating Ambitions Despite the Pandemic*, April 2021, https://www.iea.org/reports/global-ev-outlook-2021.

[196] EVConsult and Everoze, *V2G Global Roadtrip: Around the World in 50 Projects*, UK Power Networks and Innovate UK, October 2018, https://innovation.ukpowernetworks.co.uk/wp-content/uploads/2018/12/V2G-Global-Roadtrip-Around-the-World-in-50-Projects.pdf.

[197] EVConsult and Everoze, V2G Global Roadtrip; and Eurolectric, "Dynamic pricing in electricity supply," February 2017, dynamic_pricing_in_electricity_supply-2017-2520-0003-01-e.pdf.

Reusability of infrastructure, data and research results. Infrastructure and software for smart charging can be used to integrate vehicles into virtual power plants (see Chapter 4), which provide greater flexibility through aggregation.

Transferability to other industries. Electric vehicles are front-runners in mobile storage applications, and customer familiarity with them should be readily transferrable to other applications in the transport sector (such as industrial mobility, where requirements for vehicle availability and monetisation opportunity can be significantly different) and other flexibility resources (like home storage), accelerating uptake.

11.4 Technical assessment of EV smart charging

Three technical aspects of smart charging were assessed: flexibility response time to trigger, or signal, from TSO or DSO; availability throughout the day and year; and resilience to system instability.

Flexibility response time to trigger, or signal, from TSO/DSO. Electric vehicles can provide flexibility to the power system and facilitate both renewables integration, through price-responsive charging, and power-system stability. As mobile storage, EVs are not fully available at all times, but on an aggregated level, EV charging and availability follow a predictably diurnal pattern, allowing aggregators to reserve flexibility by knowing the share of EVs at certain charging locations and certain times.

The response times of vehicle batteries are generally low (within 10 seconds), but they vary depending on the implementation and market conditions[198]. EVs can be used for the provision of frequency containment reserve, and automatic frequency restoration reserve has been demonstrated[199]. For participation in variable rates and the spot market, lower response times are sufficient. (The European Power Exchange spot intraday market has a 15-minute resolution, and trading takes place up to five minutes ahead of delivery. Real-time rates from companies like Tibber in Norway and aWATTar in Austria are mostly hourly.)

Availability throughout the day and year. General availability depends on infrastructure deployment, including whether EVs can be charged at their owners' places of employment. The availability of EV flexibility resources throughout the year is assumed to be high because there are typically no substantial seasonal variations in aggregated driving patterns. Charging tends to follow a daily and weekly pattern, as illustrated in Figure 65, with long trips (due to holidays, for example) playing a minor role[200]. The availability of vehicles over the course of a day is accounted for in the calculations performed in this report.

System stability towards frequency variation. EVs' contribution to system flexibility is considered positive. They can support system stability by reducing local grid constraints when they participate in ancillary services[201]. Price-responsive charging targeting wholesale markets can also contribute

[198] "Basics of the power market," EPEX SPOT, n.d., https://www.epexspot.com/en/basicspowermarket.

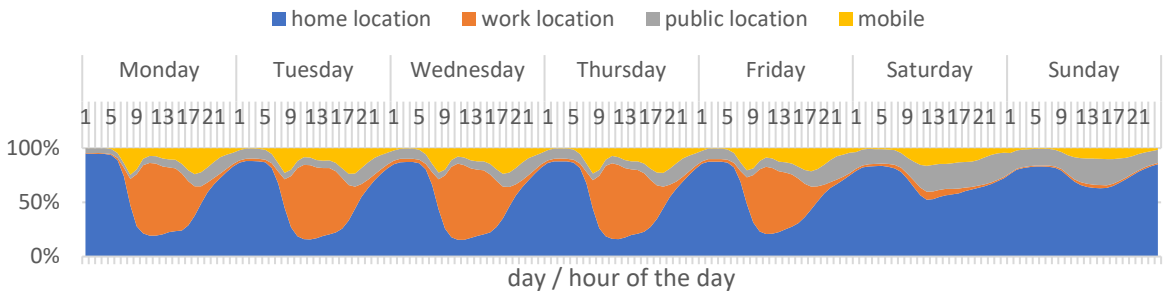
[199] TenneT TSO, "aFRR pilot end report," July 6, 2021, https://www.tennet.eu/fileadmin/user_upload/SO_NL/aFRR_pilot_end_report.pdf; and "Electric vehicles as Frequency Containment Reserves," Virta, November 14, 2019, https://www.virta.global/blog/electric-vehicles-as-frequency-containment-reserves.

[200] Till Gnann, Anna-Lena Klingler, and Matthias Kühnbach, "The load shift potential of plug-in electric vehicles with different amounts of charging infrastructure," Journal of Power Sources 390, June 2018, https://doi.org/10.1016/j.jpowsour.2018.04.029.

[201] David Dallinger, Daniel Krampe, and Daniel Wietschel, "Vehicle-to-grid regulation reserves based on a dynamic simulation of mobility behavior," IEEE Transactions on Smart Grid 2, no. 2, June 2011, https://doi.org/10.1109/TSG.2011.2131692; and

to reducing local grid constraints, but – depending on the price signal – could also lead to negative effects on the local grid.

Figure 65. Share of EVs by location throughout the day and week[202]



Analysis suggests few challenges in the technical aspects of leveraging flexibility from smart charging, though overall flexibility potential is limited because electric vehicles cannot participate in multiple business cases at once.

11.5 Technical infrastructure required for EV smart charging

The infrastructure required to implement this business case can be divided into three categories: analog, digital and analytics:

Analog. Metering is required, either as a separate smart device or embedded in a charging point[203]. Smart charging also requires communication between various entities, including the EV, the charging point and possibly one or more third parties, so communication capabilities must be included in EV hardware and software. Although interoperable protocols for EV hardware and software are already developed, clear roles for actors (for example, the tasks and duties of DSOs in unbundled energy markets) also must be defined and agreed upon[204].

Digital. A functioning concept for controlled EV charging requires multiple entities to communicate and interact through several interfaces. The most important requirements are presented in the sections below. Modern EVs do not need further technical adjustments to perform smart charging; however, to provide enough freedom to shift the charging of EVs to when prices are lowest, private and public charging infrastructure must be extended in line with the adoption of EVs.

Analytics. Necessary preconditions include services such as energy and power-flow management systems that allow for optimal EV charging (including underlying control and optimisation algorithms), intelligent charging infrastructure, and digital infrastructure for the monitoring and exchange of real-time information on the status of EVs and the power system.

Siyamak Sarabi et al., "Potential of vehicle-to-grid ancillary services considering the uncertainties in plug-in electric vehicle availability and service/localization limitations in distribution grids, Applied Energy 171, June 2016, https://doi.org/10.1016/j.apenergy.2016.03.064.

[202] Data source is Gnann, Klingler, and Kühnbach, "The load shift potential of plug-in electric vehicles."

[203] International Renewable Energy Agency (IRENA), *Innovation Outlook: Smart Charging for Electric Vehicles*, 2019, https://www.irena.org/publications/2019/May/Innovation-Outlook-Smart-Charging; and European Commission, Directorate-General for Energy, *Digital Technologies and Use Cases in the Energy Sector*.

[204] IRENA, Innovation Outlook.

Analysis suggests few challenges in the technical requirements for smart charging. The adoption of EVs is ongoing; charging, metering and communication protocols exist, and the smart meter rollout is ongoing throughout Europe.

11.6 EV smart charging risk considerations

Risks could be experienced in relation cybersecurity, technical barriers, gamification potential, and public and end-user acceptance.

Cybersecurity. Charging technologies are exposed to risks such as hacker attacks, and currently there are no standards guiding V1G and V2G product developers and service providers to develop cyber-safe products and services[205]. In addition, the virtual interaction between the various players involved is challenging; although the basic technology for controlled and bidirectional charging is available, the implementation into reality is hindered by the lack of standardised communication protocols.

Technical barriers. Most research and innovation are focused on vehicle performance (for example, ultra-fast charging) rather than on advancing V1G or V2G technologies for power flexibility purposes. This should be addressed as regulations become more detailed.

Gamification potential. As a relatively small flexibility resource, individual EVs have limited market power, so the gamification potential of price-responsive charging is also limited. However, gamification potential cannot be excluded, because the aggregator could participate in multiple markets at once. Therefore, two aspects of gamification are relevant: (1) increasing market power in primary power markets due to vast flexibility potential (i.e. an aggregator could exert outsized market power by concentrating a large number of EVs), and (2) (de)centralised secondary markets, particularly in small grid areas (i.e. an aggregator might have sufficient leverage to manipulate a decentralised secondary market).

Public and end-user acceptance. Because profitability is one of the most important ways to incentivise users to use smart-charging applications[206], it is a prerequisite for increasing public acceptance. Also, end users tend to have concerns regarding data-security and privacy issues, and they fear losing comfort and control over their charging behaviour[207]. To address the loss of comfort, the depth of battery discharge could be automatically limited as part of the business case. Data security and privacy issues could be addressed specifically within the regulatory framework.

Overall, risks for smart charging with regard to privacy, standardisation, and user acceptance are generally viewed as manageable.

11.7 Business case: Price-responsive charging

This section analyses price-responsive charging, in which the electricity price varies according to the availability of renewable energy, how many EVs charge when the price is lowest, and possibly the grid load. Price-responsive charging is feasible in various forms, the simplest of which uses a variable rate (based on time-of-use or real-time pricing) that reflects a price signal from the wholesale electricity market.

[205] Gautham Ram and Menno Kardolus, "Roadmap electric vehicles and grid integration (V1G versus V2G)," Power Research Electronics (PRE), http://www.pr-electronics.nl/en/news/85/roadmap-electric-vehicles-and-grid-integration-v1g-versus-v2g/.

[206] Joachim Globisch et al., "The stranger in the German energy system? How energy system requirements misalign with household preferences for flexible heat pumps," *Energy Research & Social Science* 67, September 2020.

[207] International Energy Agency (IEA), *Task 28: Home Grids and V2X Technologies: Final Report (2014–2018)*," 2019.

11.7.1 Potential time frame for price-responsive charging impact

Maximum adjustable power and adjustable energy are taken into account when calculating the flexibility potential of smart charging at scale. In contrast to other storage technologies, EVs applying V1G cannot provide the same amount of power in positive and negative directions. Therefore, the adjustable power is subdivided into load reduction and load upshift.

While various business cases use load upshift and load reduction to balance the energy grid, with electric vehicles a detailed analysis of these concepts is warranted because of the asymmetry between upshift and load reduction. This load flexibility asymmetry is different for smart charging (discussed here) and vehicle-to-grid applications (discussed in Chapter 12), and it is important to capture this difference because it impacts revenue opportunity and the feasibility of scaling the application.

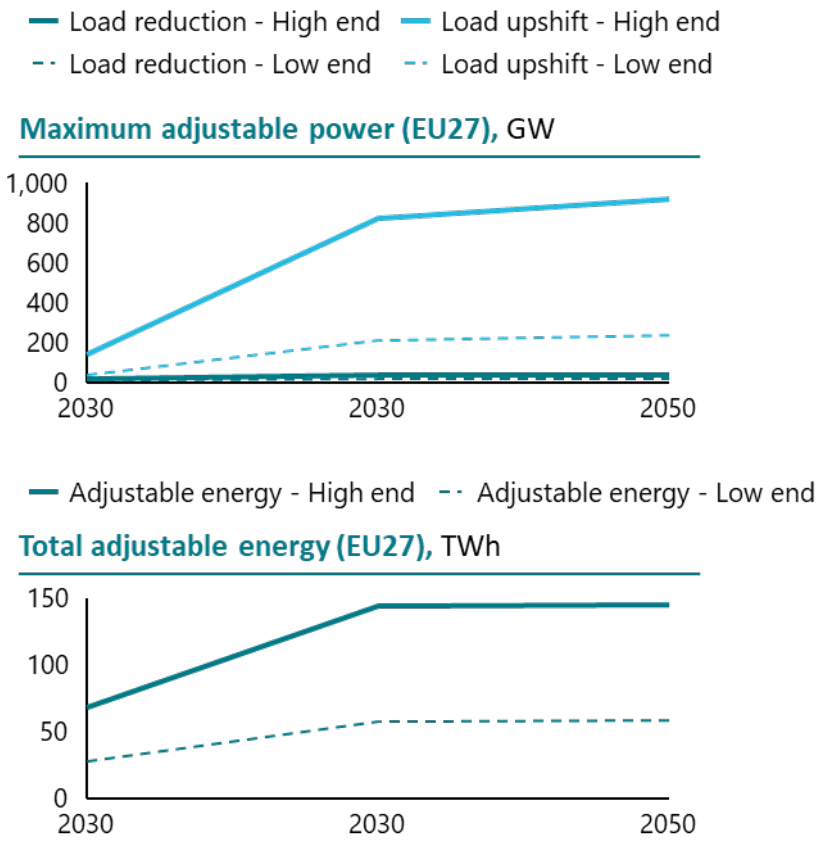
Load reduction describes the provision of negative power (i.e. a reduction of demand) by decreasing the charging load. It is calculated based on the maximal charging load of EVs. This report's analysis uses a forecast model based on metered driving profiles of conventional vehicles in Germany and scales according to the number of vehicles used in 2020, 2030 and 2050[208]. It also considers the charging locations available for price-responsive charging – that is, at home, work, and public charging stations. The more locations that can be used, the greater the potential, as more EVs are connected at the same time.

Load upshift is determined by the positive power that can be dispatched by increasing the aggregated charging load of all participating EVs. It is calculated based on the anticipated average charging capacity of the year and the number of EVs expected to be available for charging, and it considers the charging points available and the ongoing charging processes (as EVs that are already charging cannot shift their power demand up). Because a large number of EVs are connected to a charger even when they're not charging, load upshift surpasses the load reduction potential by far.

Figure 66 shows the impact of flexibility on the energy system. Both graphs present a range of results depending on the adoption rate as well as the charging locations available. For an adoption rate of 35% of the EV users charging at home and work, this analysis estimates a load reduction potential of 27 gigawatts and a load upshift potential of 551 gigawatts by 2050 (based on average of low and high-end ranges).

[208] Gnann, Klingler, and Kühnbach, "The load shift potential of plug-in electric vehicles."

Figure 66. Impact of price-responsive charging flexibility on the energy system



11.7.2 Economic assessment of price-responsive charging

This section discusses the main players associated with the price-responsive charging business case – that is, those expected to primarily implement it – and explores its economic viability for them.

The key players involved in the business case for smart charging are the end users, or EV owners, the charging-infrastructure operator, and, to some extent, the grid operators.

For end users, smart charging is attractive mainly because it offers economic benefit by allowing controlled charging at times with low wholesale prices. Charging operators, too, whether utilities or aggregators, can add to the revenue they make selling energy to EV users by pooling EVs to monetise their flexibility.

This report assumes that EVs participating in smart charging react to prices provided by a central wholesale market; however, they can also support congestion management in the transmission or distribution grid, in which case incentives would come directly from the TSO or DSO. Furthermore, studies have demonstrated smart charging of EVs alone can be beneficial for local distribution grids: If EVs are charged in a coordinated manner, the additional demand they create leads to greater use of the grid, which reduces grid charges for all consumers.

Revenue is calculated based on the 2030 European average hourly price curve, which is derived from an energy-system model that considers wholesale-based hourly electricity demand and supply from a power mix that includes conventional and renewable energy sources as well as batteries. Transmission (and therefore congestion) is regarded between countries only. The analysis of revenue for this business case and throughout this report should be considered an illustrative exercise rather than a prediction on the evolution of price over time.

Each business case is regarded independently and incrementally (that is, assuming a small amount of implementation that does not affect prices).

For optimal use of smart charging, this study assumes that EVs are connected to the charging station every day. The aggregated flexibility is based on the amount of charging actually reduced (that is, average connected charging load), not on the theoretical charging power available. However, for the optimised electricity price for charging, this analysis assumes that the delayed charging takes place with full charging power – that is, only 414 hours a year or 1.8 hours a day.

The daily charging time of 1.8 hours is then optimised to take place when power prices are lowest; the price difference gained is considered revenue.

The profitability of smart charging depends heavily on intraday price spreads and competition with other flexibility resources. Slight savings on electricity bills cannot compensate for regulatory and administrative barriers, though, or for possible barriers to individual ownership, such as vehicle cost, driving range and long charging times, so the stimulus for implementation would have to come from other sources, such as subsidies for smart charging or a reduction of fiscal charges for electricity.

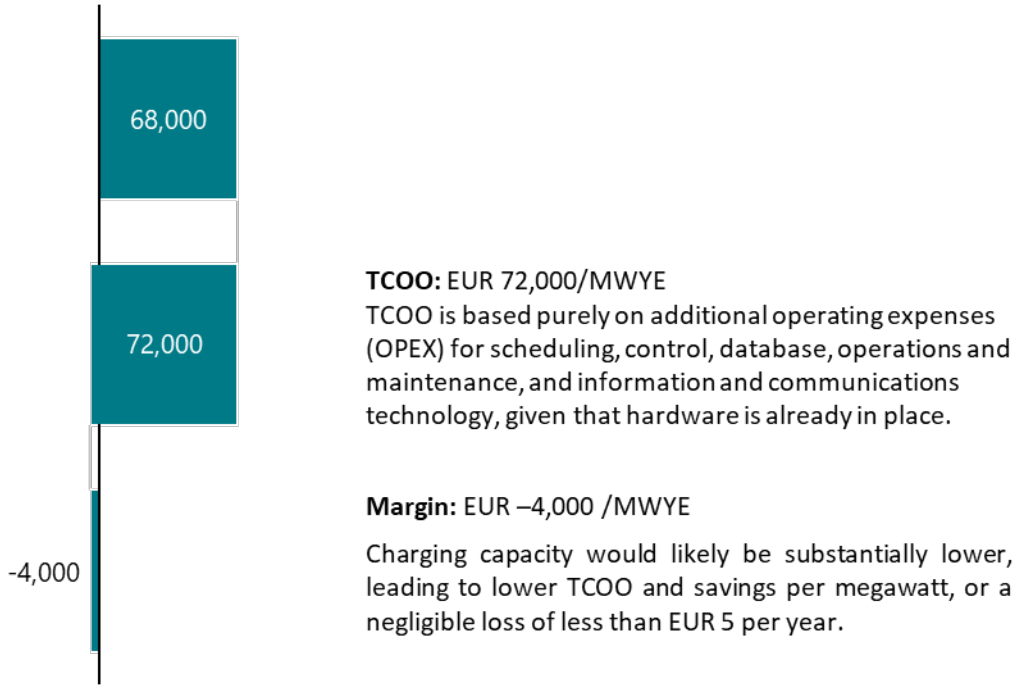
The calculations in this report are based on an adoption rate of 35% and on charging at home and work only. The following parameters were used in the estimation of revenues:

- adjustable energy: 47.6 terawatt hours
- load reduction: 12.7 gigawatts (based on average connection)
- full-load hours for deferred charging: 414 a year
- interval length for each cycle to take place in: 24 hours
- run time per interval: 1.8 hours

Full-load hours per year is driven by low consumption relative to available charging power. It has a negative influence on the savings per car, which is lower than in other business cases at around EUR 45 a year, because the flexible price component assumed – the generation, or wholesale electricity cost – only covers a small fraction of the retail electricity cost. If other components of the retail price, such as grid fees or taxes, are cost-reflective, more savings are possible.

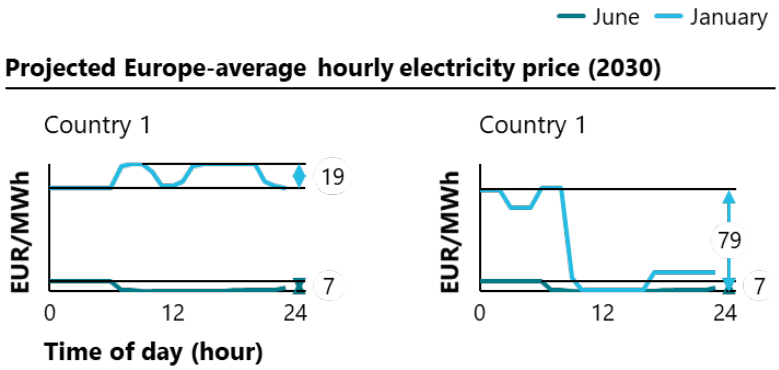
On an aggregated level, the revenue calculation for price-responsive charging also includes an average saved electricity cost of EUR 18 per megawatt hour and an estimated revenue of EUR 68,000 per megawatt year, as shown in Figure 67.

Figure 67. Estimated operating margin for price-responsive charging, EUR/MWYE



In this model, the spread between the highest and lowest prices on a given day has a strong influence on operating margin. Prices can vary significantly depending on factors including share of solar energy and build-out of transmission, as shown in Figure 68.

Figure 68. Price spread for two hypothetical countries on days in June and January for the price-responsive charging business case



Other points to consider include:

- A potential rebound effect of a lower EV charging cost could be an increase in EV users' mobility, leading to higher electricity demand.
- Revenue may have to be split between multiple parties.
- EV smart charging may see additional revenues in the future; for example, it may incentivise people in a specific area to delay consumption when the grid is heavily congested.
- Analysis suggests moderate challenges in the viability of smart charging for flexibility, because its profitability depends heavily on price spreads and competition with other flexibility resources, cost savings cannot compensate for other barriers and savings in both the system cost and the power cost are very low for each individual car owner.

11.7.3 Total cost of ownership for EV smart charging

Total cost of ownership calculations are based on a load-reduction potential of 12.7 gigawatts by 2030, assuming a 35% adoption rate (corresponding to approximately 19.2 million EVs) and assumed charging locations at home and work. For the flexible capacity this analysis assumes an adoption range from 20% to 50%. For the lower end, this analysis considered home charging only, while for the upper end, work and public charging were assumed as well.

There are no capital expenses for this business case because smart, unidirectional stations and smart meters will be in place by 2030. Operating expenses – including scheduling, control, database, and operations and maintenance – are assumed to be EUR 48 a year per EV. The cost of operations may also vary according to the form of participation in a business case; for example, prequalification may increase costs.

OPEX is EUR 72,000 per megawatt year. This number is calculated by multiplying the single-car OPEX of EUR 48 a year by the total number of EVs participating in this business case in 2030, divided by the load reduction potential calculated for this business case.

Because of a lack of data, it is not possible to provide in-depth information on specific asset cost and other additional costs of smart charging; however, they are expected to be low, as most technological requirements are already integrated.

11.8 Business case: Self-consumption optimisation using EVs

EV self-consumption optimisation uses electric vehicles as storage for households with a renewable electricity supply unit, most often a solar photovoltaic panel. This is becoming an increasingly attractive option as electricity prices rise and the prices of PV systems falls.

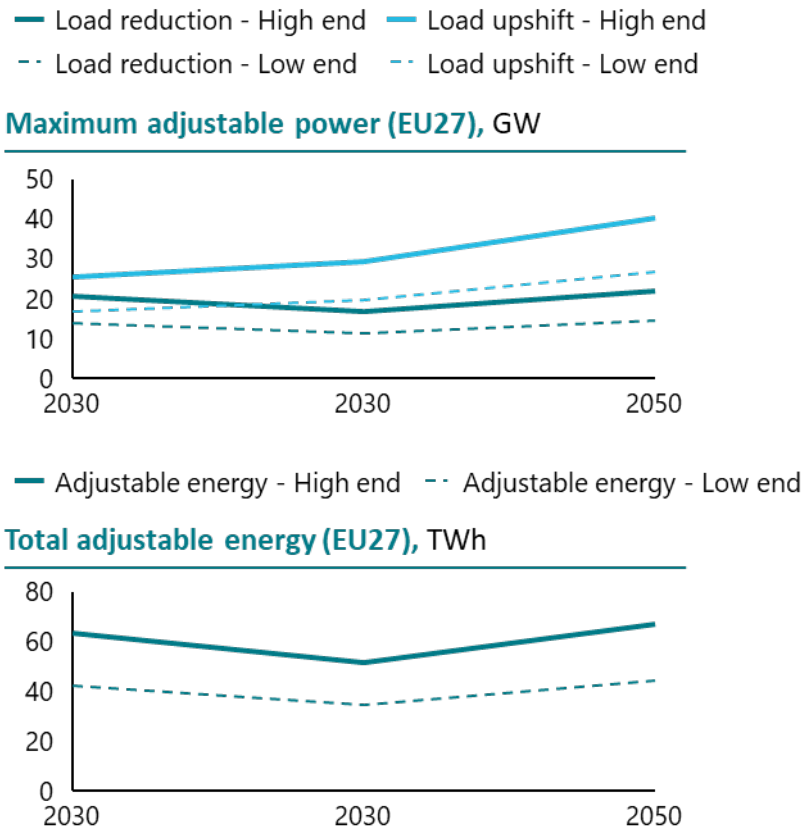
11.8.1 Potential time frame for self-consumption optimisation using EVs impact

The main drivers for the flexibility potential of this business case are the number of PV units on European rooftops, the share of PV-equipped households with an electric vehicle and the power-consumption demand of those households. In the framework of self-consumption, EV charging aims to maximise a household's self-supply of electricity, so the total adjustable capacity for load upshift using EVs is restricted by the household's residual PV generation, or the maximum PV generation minus the household load covered by the PV supply. If 60% of PV-equipped households adopted this technology (midway the adoption range of 50–75% shown Figure 69), the load upshift could reach 20.3 gigawatts by 2030 and 32.3 gigawatts by 2050.

Although EV load upshift is limited by the capacity of PV generation, EV load reduction is the maximum aggregated charging load of cars charged only at home[209]. The resulting load reduction of the business case, depending on the adoption rate, is shown in Figure 69; with 60% adoption (midway the adoption range of 50–75% shown in the Figure), it would be 16.6 gigawatts in 2030 and 17.5 gigawatts in 2050.

[209] Gnann, Klingler, and Kühnbach, "The load shift potential of plug-in electric vehicles."

Figure 69. Impact self-consumption optimisation using EVs flexibility on the energy system



To calculate the flexibility at stake, the following assumptions were made:

Self-consumption requires that a generation unit is installed on the premises of the user. This analysis assumes that this generation unit is exclusively rooftop PV, so in our scenario, self-consumption of EVs can take place only at dwellings with rooftop PV systems.

Concerning the distribution of EVs among households, this analysis assumes that 80% of all households with a rooftop PV unit also have an EV.

The self-supply of a household with rooftop PV is higher when stationary storage is available, but because this setup does not allocate adjustable power to the EV, it is not considered here.

In 2050, a total of 57.6 million households (2030: 34.1 million households) can participate in self-consumption, including an EV. The installed PV capacity of these households equals 161.4 gigawatts in 2030 and 258.5 gigawatts in 2050.

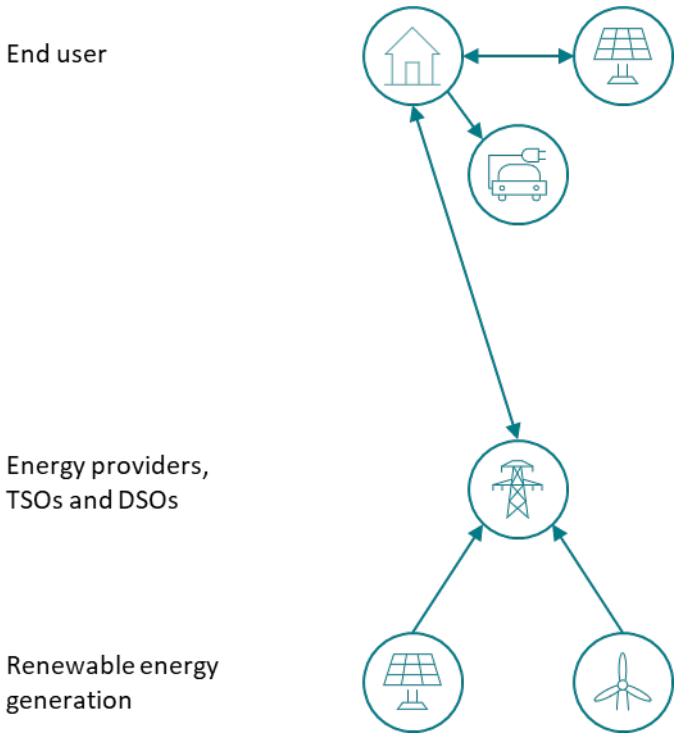
Due to the popularity of self-consumption, this analysis estimates that a large share of self-consumers with EVs integrate the vehicle into their self-consumption routine. The adoption rate of integrating EVs into self-consumption is assumed to be 50% to 75%.

Based on available data, it is assumed that the amount of time a vehicle is at home is sufficient for load shifting while still satisfying mobility needs. (In a typical week, users do not need to charge their vehicle at work or at public charging points, and unusually long trips – for example, during holidays – do not Figure into these calculations.)

11.8.2 Economic assessment of self-consumption optimisation using EVs

This section discusses the main players associated with the self-consumption optimisation using EVs business case – that is, those expected to primarily implement it – and explores its economic viability for them. Figure 70 shows a schematic of the power and energy flow for this business case as well as the players relevant in each step.

Figure 70. Power and energy flow for the EV self-consumption optimisation business case



For the end user, high electricity prices – and smart charging – favour self-consumption, as does smart charging.

Net metering would reduce the attractiveness of this business case.

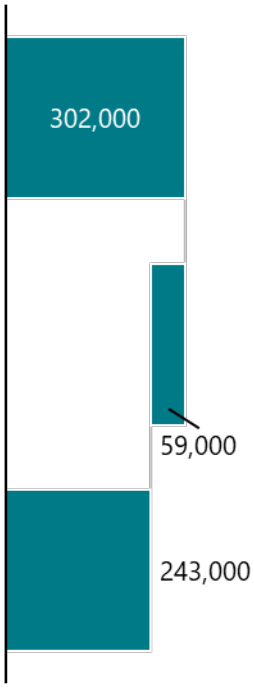
For the TSO/DSO, demand and supply peaks are reduced or increased depending on regulations, and they impact the complexity of operations because power grids can become unstable from sudden large load or power-supply fluctuations. Electric vehicles can help deal with such instability if they're used correctly; if they're not used correctly, however, EVs can significantly complicate grid operations by contributing to instabilities.

Revenue is derived mainly by avoiding taxes and fees thanks to self-supply.

This analysis uses average retail prices including 2020 tax and fee rates provided by Eurostat[210], and it assumes that savings apply to all price components. As the power cannot be sold on the spot market, the wholesale price – based on the 2030 European average hourly price curve derived from a model that considers conventional and renewable energy sources as well as batteries – is subtracted from this sum. The estimation of revenue and TCOO is shown in Figure 71.

[210] Eurostat10Electricity prices for household consumers – bi-annual data (from 2007 onwards), dataset, last update October 26, 2021, Europa, https://ec.europa.eu/eurostat/databrowser/view/NRG_PC_204/default/table?lang=en.

Figure 71. Estimated operating margin for self-consumption optimisation using EVs



Estimated revenues: EUR 302,000/MWYE

Estimated revenues are based on an estimated power price reduction of 164/MWh if taxes and fees do not have to be paid due to self-consumption; this figure is highly dependent on regulation.

TCOO: EUR 59,000/MWYE

TCOO is based purely on additional OPEX for scheduling, control, database, operations and maintenance, and ICT, given that hardware is already in place..

Margin: EUR 243,000/MWYE

Margin is based on load reduction values calculated for the systemic impact of this business case for 2030. The installed charging capacity is expected to be substantially higher, which would lead to lower TCOO and greater cost savings per megawatt — approximately a EUR 200 per year margin per car.

Under the current regulatory framework, this research expects few challenges to arise for the integration of EVs into the prosumer self-consumption market.

It is assumed that 60% of the charging necessary to fulfill all mobility needs can be shifted to hours with sufficient self-generation. Calculations multiplied the self-consumed share of the adjustable energy with the estimated savings. For the denominator (that is, the megawatts), the load-reduction values calculated for the systemic impact of the business case were used.

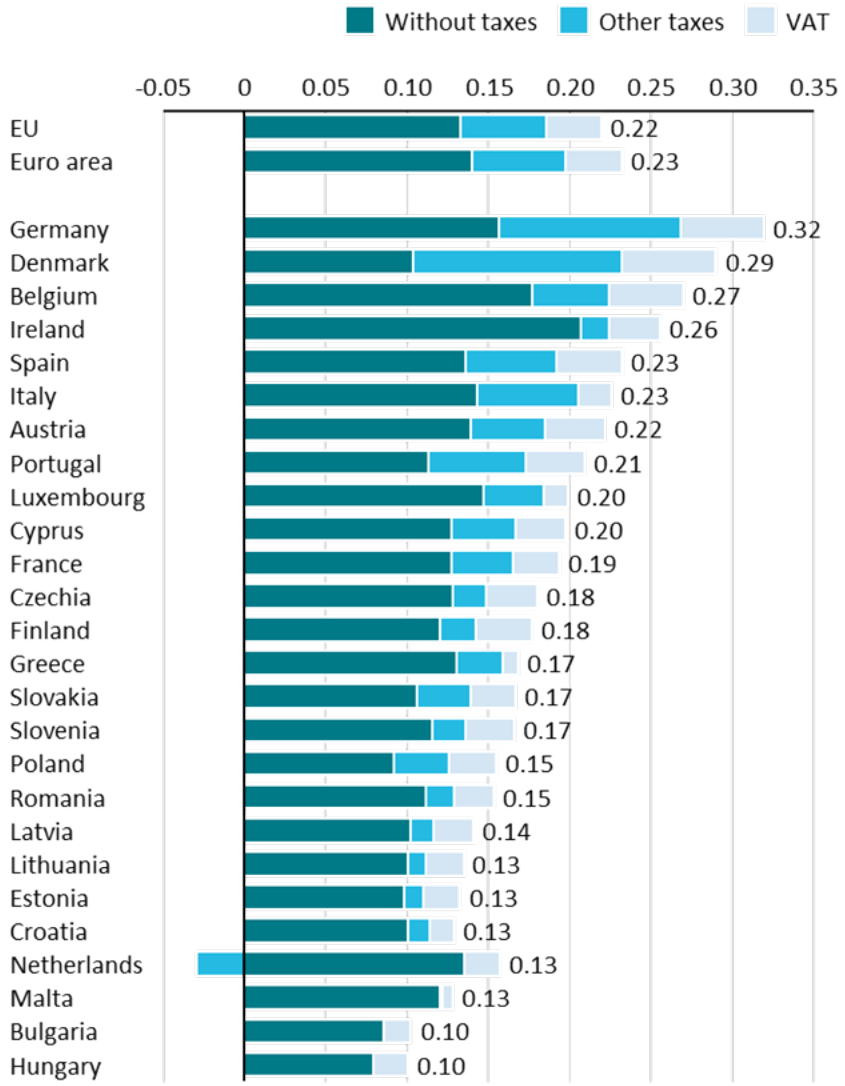
Revenue calculations are based on an adoption rate of 60% (among households possessing a rooftop PV system) and a total EV fleet of approximately 20.5 million EVs, which would lead to a load reduction of 16.6 gigawatts in 2030. Other parameters include:

- The self-consumption share of EV charging energy is 60%.
- The average 2020 EU retail electricity price, including taxes and fees is EUR 213 per megawatt hour.
- The average wholesale price in 2030 is EUR 49 per kilowatt hour.

Calculations are based on vehicle aggregation. An average of EUR 164 per megawatt hour of electricity should be saved, and the revenue is estimated at EUR 302,000 per megawatt year. For one vehicle, optimised charging is expected to save EUR 245 per EV annually.

Taxes and fees on consumer electricity prices are essential to this business case, as are the degree to which these taxes and fees are reduced for self-consumption. These costs vary significantly across countries today, as indicated by retail prices shown in Figure 72, and they may change in the future – which could significantly affect profitability.

Figure 72. Average retail electricity prices for EU households in the first half of 2021, in euros per kilowatt hour[211]



Other points to consider include the following:

The amount of self-consumed electricity can be further increased through a larger PV unit as well as through the use of home storage, though both increase overall costs.

Depending on system design, benefits can be relatively low, especially in winter.

This business case could be combined with price-responsive charging to reduce costs for charging from the grid.

Tax and fee differences among countries, as well as the future design of price components and regulatory frameworks for self-consumption, can affect this business case.

The decreased cost of EV charging may have rebound effects, including incentivising increased annual mileage.

[211] Ibid.

While the revenues and saved electricity costs look positive, this assessment is highly uncertain due to significant uncertainty in estimating the underlying retail prices, fiscal charges, and regulations for self-consumption, both in the future and from country to country. However, the Renewable Energy Directive 2018/2001/EU as well as the revision of this directive proposed in 2021 specifically support self-consumption schemes[212].

11.8.3 Total cost of ownership for EV smart charging

TCOO calculations are based on an adoption rate of 60% (among households possessing a rooftop PV system) and a fleet of approximately 20.5 million EVs, which would lead to a load-reduction of 16.6 gigawatts by 2030. Only home charging is considered in this business case, and parameterisation is done for a single EV. Therefore, the OPEX of EUR 48 a year was scaled using the total number of EVs employing self-consumption in 2030 divided by the adjustable capacity calculated for this business case.

No additional capital costs are considered, as most chargers already allow for smart charging.

Overall, this analysis suggests few challenges in providing flexibility through smart charging. Price-responsive charging and self-consumption have the same TCOO values on the low end of the cost scale, only charging at home. If public and work locations are taken into account, the adjustable power increases, decreasing the TCOO value.

[212] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32018L2001&from=fr

12 Use case: Vehicle to grid

Vehicle-to-grid charging, or V2G, is also called bidirectional charging, because it comprises all activities in which power from an EV is fed back to the grid. V2G makes EVs, as a paper in *Environmental Research Letters* in 2018 put it, "self-contained resources that can manage power flow and displace the need for electric utility infrastructure"[213].

V2G is currently in the pilot stage. EVs capable of bidirectional charging are rare, and the chargers are substantially more expensive than smart chargers because they are still being developed. Furthermore, standardised V2G communication protocols are not established[214]. Users also face other obstacles, including battery degradation, fear that they will lose control over the battery status of their EV, and regulatory considerations[215]. For these reasons, this analysis assumes that the participation rate of products and services related to V2G is substantially lower than that of smart charging, covered in Chapter 11.

This Chapter examines two business cases:

Price-responsive bidirectional charging. EVs adjust their charging pattern to respond to real-time or time-of-use price signals. By 2050 price-responsive bidirectional charging is expected to provide the European Union with 477 gigawatts of power – 241 gigawatts discharged to the grid and 236 gigawatts in load upshift. (For more on discharge to grid and load upshift, see Section 11.7.1.)

Congestion management and ancillary services using V2G. EVs applying V2G participate in the congestion and ancillary markets. By 2050 congestion management and ancillary services through EVs are expected to provide the European Union with 307 gigawatts of power – about equally divided by discharge to grid and load upshift.

The flexibility potential of smart charging is always limited by the energy user's demand, because the priority is to satisfy the user's mobility needs. Flexibility potential is different in V2G, where additional charging takes place only for the purpose of discharging at another time to take advantage of the price spread, and it is thus decoupled from the users' mobility needs.

12.1 Market overview for V2G

This section provides an overview of companies that offer services or general infrastructure for V2G applications. Although the focus of this report is the European market, non-European companies that are seen as pioneers in these fields are also discussed.

A growing number of companies are developing V2G charging infrastructure. Currently, North America is the leading region for the global V2G market due to rapid investments towards

[213] Benjamin K. Sovacool et al., "The neglected social dimensions to a vehicle-to-grid (V2G) transition: a critical and systematic review," *Environmental Research Letters* 13, no. 1, January 2018, https://iopscience.iop.org/article/10.1088/1748-9326/aa9c6d/pdf.

[214] International Organization for Standardization, ISO/FDIS 15118-20, https://www.iso.org/standard/77845.html; and Nationale Plattform Elektromobilität (NPE), Roadmap to the implementation of ISO 15118], 2020, https://www.plattform-zukunft-mobilitaet.de/en/2download/roadmap-zur-implementierung-der-iso-15118-standardisierte-kommunikation-zwischen-fahrzeug-und-ladepunkt/.

[215] International Energy Agency (IEA), *Task 28: Home Grids and V2X Technologies: Final Report (2014 - 2018*), 2019; Seyfettin Vadi et al., "A review on communication standards and charging topologies of V2G and V2H operation strategies," *Energies* 12, no. 19, https://doi.org/10.3390/en12193748; and Sovacool et al., "The neglected social dimensions to a vehicle-to-grid (V2G) transition: a critical and systematic review."

establishing the V2G supply chain, but numerous demonstration projects elsewhere promise growth in the broader V2G market[216].

Variable rates and smart-charging products are gradually appearing in many countries, but currently there is no defined market for smart charging. Table 24 lists European operators of charging infrastructure.

Table 24. Vehicle-to-grid market infrastructure and service providers

	Company	Headquarters' location
Manufacturers of charging infrastructure	ABB	Switzerland
	EVBox	Netherlands
	myWallbox	Spain
Operators of charging infrastructure	Allego	Netherlands
	Enel X	Italy
	EVBox	Netherlands
	Ionity	Germany
	Has-to-be	Netherlands
	Shell Recharge Solutions	Netherlands
V2G service providers	Nuvve	US
	Stellantis	Netherlands
	The Mobility House	Germany
	Virta	Finland

In Europe, the V2G market is still in an early stage, and it is dominated by research and pilot projects.

12.2 Stakeholder mapping for V2G

Stakeholders for this use case include consumers, governments, energy-industry businesses and the environment.

Impacts on these stakeholders are similar to those outlined in Chapter 11, except that for consumers, V2G allows the vehicle's battery to be used to a larger extent and for more purposes, such as providing power to bulk or balancing markets or to the EV user's household. Intensified use of the battery, however, leads to increased battery degradation, which can have negative impacts including decreased battery lifespan and capacity. For manufacturers of vehicles and charging infrastructure, an increasing demand for V2G-ready devices could lead to additional revenue, but market uptake depends on the availability of V2G-ready vehicles and charging infrastructure, as well as on substantial price reductions for V2G components.

[216] European Commission, Directorate-General Energy, Jakeman, Achtelik, and Makwana, Digital Technologies and Use Cases in the Energy Sector; and Frost & Sullivan, Developments in Vehicle-to-Grid (V2G) Technology: Transformational Technology Influencing Electric Vehicles and Smart Grids, 2017.

12.3 Innovation assessment for V2G

Europe is currently experiencing a strong market uptake of electric vehicles[217]. As renewable energies are expanded and conventional power plants phased out, the need for flexibility will likely increase, and EVs could help to address this need. Numerous research projects on smart charging and V2G are ongoing worldwide, including in Europe. Both home charging stations and corresponding software are already commercially available for smart charging (V1G), but they are not yet ready for V2G.

12.3.1 European innovation position

This section provides a qualitative assessment of the innovation position of the European Union based on a review of the literature and interviews with experts.

Market positioning of European firms. Although a bidirectional charger by myWallbox is already commercially available in Europe and although other European manufacturers including Volkswagen and ABB have announced that bidirectional chargers and V2G-ready vehicles will be commercially available in the near future, availability of V2G-ready charging infrastructure is rare in Europe.

- *Share of European firms in the supplier and customer network.* Although smart charging and bidirectional products are gradually appearing in many countries, no "market" for V2G currently exists, thus market shares are not given here. However, European companies are heavily involved in V2G research and pilot projects; approximately 50% of the V2G research projects worldwide are in Europe[218].
- *Level of innovation in the European Union.* Driven by ongoing pilots, some utilities have launched their own V2G services or started partnerships (for example, Enel X and Nissan, E.ON and Nissan, and EVBox and The Mobility House[219]). One joint venture has also been started: In 2019, the US-based charging manufacturer Nuvve and EDF Pulse Croissance, the investment fund and incubator of the French utility EDF, partnered to form Dreev, which manages smart charging and discharging and handles energy flexibility services.

  The Netherlands, Denmark, the UK, and Germany lead in pilot projects[220].
- *Enabling environments (e.g. research institutes).* Research institutes and innovative service providers in the field of V2G are The Mobility House (Germany); Enel Energia, Nissan Italia and the Italian Institute of Technology (Italy); Alliander and TU Delft (Netherlands); Renault and Empresa de Electricidade da Madeira (Portugal); and Northern Powergrid, Hitachi Europa Ltd. and Cenex (UK).

Few risks are expected in terms of the European V2G innovation position, but the challenges are more substantial than for smart charging. European companies that are strongly involved in pilot projects and building services and platforms are, in many cases, dependent on hardware from outside of Europe.

[217] Europe Beyond Coal, *Overview: National coal phase-out announcements in Europe: Status 03 August 2021*, 2021; and Everoze and EVConsult, *V2G Global Roadtrip: Around the World in 50 Projects*, October 2018, https://innovation.ukpowernetworks.co.uk/wp-content/uploads/2018/12/V2G-Global-Roadtrip-Around-the-World-in-50-Projects.pdf.

[218] Everoze & EVConsult. V2G Global Roadtrip: Around the World in 50 Projects.

[219] Ibid

[220] Ibid.

12.3.2 Spillover effects

The following indirect benefits from smart charging innovation could emerge:

Reusability of infrastructure, data and research results. V2G infrastructure and software can be used to integrate vehicles into virtual power plants (see Chapter 4), which provide greater flexibility through aggregation.

Transferability to other industries. Electric vehicles are front-runners of mobile storage applications, and customer familiarity with them should be readily transferrable to other applications in the transport sector and other flexibility resources, like home storage, accelerating uptake.

12.4 Technical assessment of V2G

Three technical aspects of smart charging were assessed: flexibility response time to trigger, or signal, from the TSO or DSO; availability throughout the day and year; and active contribution to improving system instability.

Electric vehicles can provide flexibility to the power system and facilitate renewables integration (through price-responsive bidirectional charging) and power-system stability. As mobile storage, EVs are not fully available at all times, but on an aggregated level, EV charging and availability follow a predictably diurnal pattern, which helps determine optimal charging and discharging times and makes grids less susceptible to variations that can lead to instability.

Flexibility response time to trigger, or signal, from the TSO or DSO. Electric vehicle batteries' flexibility response times are low, and vary depending on the underlying business case implementation and market conditions[221]. For participation in variable rates and the spot market, lower response times are sufficient. (The European Power Exchange spot intraday market has a 15-minute resolution, and trading takes place up to five minutes ahead of delivery. Real-time rates from companies like Tibber, in Norway, and aWATTar, in Austria, are mostly hourly.) The use of EVs for the provision of frequency containment reserve and automatic frequency restoration reserve has been demonstrated[222].

Availability throughout the day and year. General availability depends on infrastructure deployment, including whether EVs can be charged at their owners' places of employment. The availability of EV flexibility resources throughout the year is assumed to be high because there are no substantial seasonal variations in aggregated driving patterns. Charging typically follows a daily and weekly pattern, as illustrated in Figure 73, with long trips (due to holidays, for example) playing a minor role[223]. The availability of vehicles over the course of a day is accounted for in the calculations performed in this report.

Contribution to system stabilisation. EVs' contribution to system flexibility is considered positive. EVs can support the reduction of local grid constraints by participating in corresponding ancillary services[224]. Price-responsive bidirectional charging targeting wholesale markets can also contribute

[221] EPEX SPOT. Basics of the Power Market. [July 30, 2021]; https://www.epexspot.com/en/basicspowermarket.

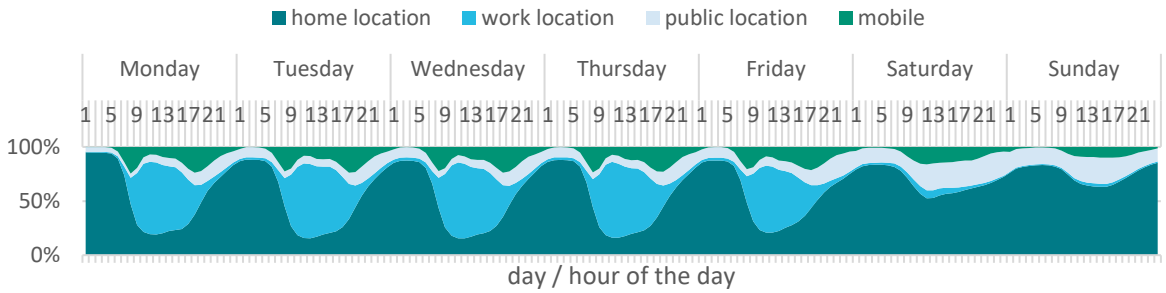
[222] David Dallinger and Martin Wietschel, "Grid integration of intermittent renewable energy sources using price-responsive plug-in electric vehicles,"Renewable and Sustainable Energy Reviews 16, no. 5, https://doi.org/10.1016/j.rser.2012.02.019.

[223] Til Gnann, Anna-Lena Klingler, and Matthew Kühnbach, "The load shift potential of plug-in electric vehicles with different amounts of charging infrastructure," Journal of Power Sources 390, June 2018, https://doi.org/10.1016/j.jpowsour.2018.04.029.

[224] Innogy, *FAQ — Häufig gestellte Fragen rund um Netzanschluss, Montage, Inbetriebnahme, Produkte, Abrechnung und Lieferung von Strom [FAQ — Frequently Asked Questions About Grid Connection, Assembly, Commissioning Products, Billing, and Supply of Electricity]*, https://dressel-egu.de/fileadmin/DRESSEL/Dokumente/FAQs_emone.pdf; and Siyamak Sarab et. al, "Potential of vehicle-to-grid ancillary services considering the uncertainties in plug-in electric vehicle availability and service/localization limitations in distribution grids," *Applied Energy* 171, June 2016, https://doi.org/10.1016/j.apenergy.2016.03.064.

to reducing local grid constraints, but depending on the price signal, could also lead to negative effects on the local grid.

Figure 73. Availability of EVs by location throughout the day and week[225]



Analysis suggests few challenges will arise in the technical aspects of leveraging flexibility from EVs, though overall flexibility potential is limited because electric vehicles cannot participate in multiple business cases at once.

12.5 Technical infrastructure required for V2G

The infrastructure required to implement this use case can be divided into three categories: analog, digital and analytics:

Analog. Widespread adoption of EVs whose hardware, software and protocols support bidirectional charging is a prerequisite for V2G, as are public and private smart-charging points that support bidirectional charging. As part of this infrastructure, consumption metering is needed for billing purposes; it can be in the form of a separate smart metering device or can be embedded in a charging point

Digital. A functioning concept for controlled EV charging requires communication and interaction between multiple entities through several interfaces with common interoperable standards and clear definitions and roles for each actor. The relevant protocols and regulations involved are described in Chapter 16.

Analytics. Metering and billing infrastructure that distinguishes between electricity consumption and revenue from flexibility provision is required. V2G services (including underlying control and optimisation algorithms), intelligent charging infrastructure, and a secure digital infrastructure for the monitoring and exchange of real-time information on the status of EVs and the power system are also required.

Analysis suggests moderate challenges in the technical requirements for V2G. Currently, the number of vehicle manufacturers and V2G infrastructure manufacturers is limited, and infrastructure is more costly than single-directional smart charging.

12.6 Risk considerations for V2G

V2G presents higher risks than smart charging. Risks could be experienced in relation to cybersecurity, technical barriers, gamification potential, and public and user acceptance:

[225] Innogy, *FAQ*; and Sarab et al., "Potential of vehicle-to-grid ancillary services considering the uncertainties in plug-in electric vehicle availability and service/localization limitations in distribution grids."

- *Cybersecurity*. With regard to cybersecurity, the same barriers apply for V2G as for smart charging, as both use the same interfaces, hardware and software, but V2G is exposed to additional risks because the chargers are interconnected in the cloud, which is vulnerable to hackers[226]. Also, interfaces are not standardised; updating protocols could allow for seamless communication between various parties and easier integration of EVs into an aggregator's portfolio.

Technical barriers. The technical barriers of V2G are also more challenging. V2G hardware is less diverse than the hardware required for smart charging, because fewer car and infrastructure manufacturers support bidirectional charging. This lack of hardware may limit interoperability and may limit rollout to specific vehicle fleets[227]. Not only does V2G require a greater initial investment than smart charging[228], but also, because batteries lose capacity over time, the amount of energy transferred to the grid will decrease[229].

Gamification potential. The gamification potential for V2G is the same as that for smart charging, but with an additional risk. Because both charging and discharging affect the grid with V2G, each EV can have double the effect a single EV has with V1G, increasing the risk that individual aggregators of EVs can exert outsised market power.

Public and user acceptance. Again, public and user acceptance issues are the same as for smart charging. In addition, at least one study showed that V2G is less popular than smart charging because it takes some control away from vehicle owners and because owners fear encountering unexpected low batteries, especially in case of emergency, and they worry about transparency in this regard.[230]

12.7 Business case: Price-responsive bidirectional charging

12.7.1 Potential time frame

V2G, which has only been tested in pilot projects, is expected to be adopted less quickly than smart charging. Communication protocols, bidirectional charging points and vehicles ready for V2G are rare; major infrastructure deployment is required to enable it. Consequently, moderate challenges may arise in terms of feasibility.

The total adjustable power by 2050 depends on both the uptake of EVs in Europe and the participation, or adoption rate, of EVs in V2G for flexibility purposes. To calculate adjustable power and energy, this analysis assumes the adoption rate of V2G to be between 10% and 25%.

To calculate V2G's flexibility potential, the maximum adjustable power (in gigawatts) and the adjustable energy (in terawatts) are taken into account.

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[226] Gautham Ram and Menno Kardolus, *Roadmap Electric Vehicles and Grid Integration (V1G versus V2G)*, n.d, http://www.pr-electronics.nl/en/news/85/roadmap-electric-vehicles-and-grid-integration-v1g-versus-v2g/.

[227] Ram and Kardolus, *Roadmap Electric Vehicles and Grid Integration (V1G versus V2G)*; and ENTSO-E, *Electric Vehicle Integration into Power Grids: Position Paper*, 2021, https://eepublicdownloads.entsoe.eu/clean-documents/Publications/Position%20papers%20and%20reports/210331_Electric_Vehicles_integration.pdf.

[228] Ram and Kardolus, *Roadmap Electric Vehicles and Grid Integration (V1G versus V2G)*.

[229] Vadi et al., "A review on communication standards and charging topologies of V2G and V2H operation strategies."

[230] Emma Delmonte et al., "What do consumers think of smart charging? Perceptions among actual and potential plug-in electric vehicle adopters in the United Kingdom," *Energy Research & Social Science* 60, February 2020, https://doi.org/10.1016/j.erss.2019.101318.

For bidirectional charging, the adjustable power is subdivided into load upshift and discharge to grid. While various business cases analysed in this report use load upshift and load reduction to balance the energy grid, with electric vehicles a detailed analysis of these concepts is warranted because of the asymmetry between them. This load flexibility asymmetry is different for smart charging (discussed in Chapter 11) and vehicle-to-grid applications (discussed here), and it is important to capture this difference because it impacts revenue opportunity and the feasibility of scaling the application.

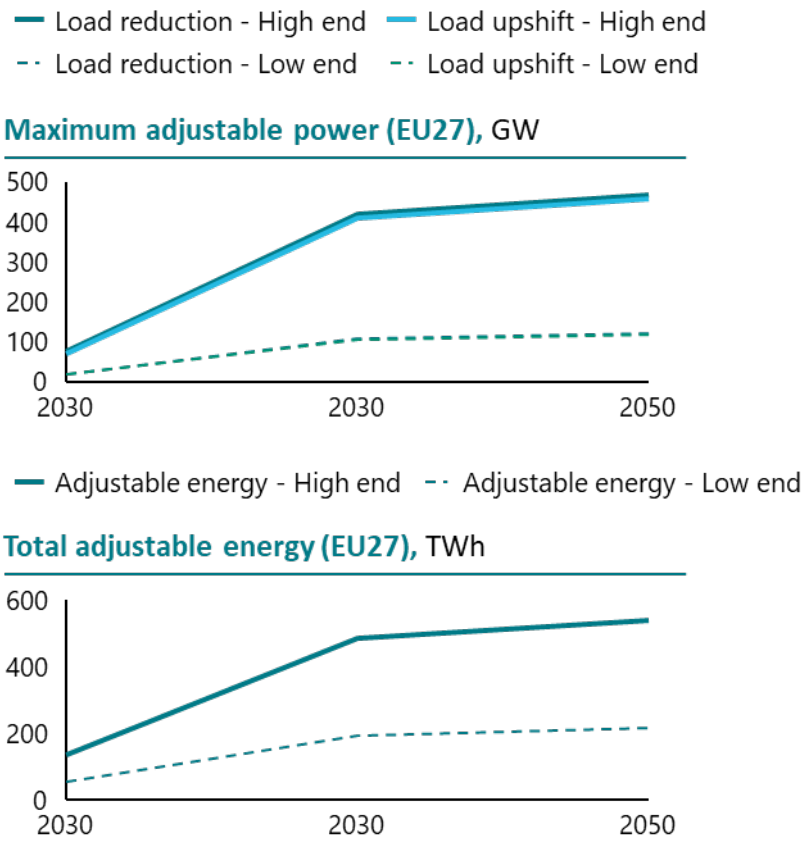
Discharge to grid describes the provision of negative power (i.e. a reduction of demand) by decreasing the charging load. It is calculated using the maximal charging load of EVs. This report's analysis employed a forecast model based on metered driving profiles of conventional vehicles in Germany and scaled according to the number of vehicles used in 2020, 2030 and 2050[231]. It also considers the charging locations available for price-responsive bidirectional charging – that is, at home, work and public charging stations. The more locations that can be used, the greater the potential, as more EVs are connected at the same time.

Load upshift is determined by the positive power that can be dispatched by increasing the aggregated charging load of all participating EVs. It is calculated based on the anticipated average charging capacity of the year and the number of EVs expected to be available for charging, and it considers the charging points available and the ongoing charging processes (as EVs that are already charging cannot shift their power demand up). Because a large number of EVs are connected to a charger even when they're not charging, load upshift surpasses the load reduction potential by far.

Unlike for smart charging, the adjustable energy for V2G is not limited to satisfying the EV users' mobility needs, so this analysis assumes that the adjustable energy corresponds to one battery cycle per day. Battery degradation can be reduced by avoiding a low-battery state of charge through V2G. Therefore, this analysis assumes that only 50% of the battery capacity of an EV is available for V2G. The resulting available capacity and total adjustable energy are shown in Figure 74.

[231] Gnann, Klingler, and Kühnbach, "The load shift potential of plug-in electric vehicles with different amounts of charging infrastructure."

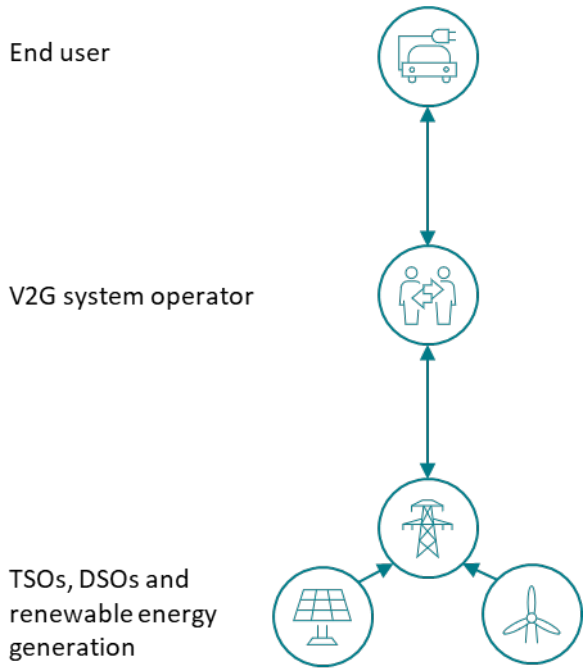
Figure 74. Impact of EV price-responsive bidirectional charging flexibility on the energy system



12.7.2 Economic assessment

This section discusses the main players associated with the price-responsive bidirectional charging business case – that is, those expected to primarily implement it – and explores its economic viability for them. Figure 75 shows a schematic of the power and energy flow for this business case as well as the players relevant in each step.

Figure 75. Power and energy flow for the price-responsive bidirectional charging business case



End users generate income from arbitrage trading, which exploits difference in an asset's price. V2G could be more profitable than smart charging, as spreads can be exploited more often[232], but end users may also experience a decrease in convenience. Additionally, battery degradation increases because of more and larger cycles, although time ages the battery more than cycling does.

V2G system operators monetise the charging and discharging of EVs and then pass part of the savings on to owners. Excluding fiscal charges, price-responsive bidirectional charging can create substantial savings for the user and can create revenue streams for an aggregator through arbitrage trading as well.

Revenue is calculated based on the 2030 European average hourly price curve, which is derived from a model that considers wholesale-based hourly electricity demand and supply from a power mix that includes conventional and renewable energy sources as well as batteries. Only transmission (and therefore congestion) between countries is considered.

Price-responsive V2G charging builds onto the business case of unidirectional price-responsive charging by allowing EV batteries to optimise charging and discharging for a total of 1,650 to 2,070 hours per year rather than charging for only around 400 hours. Per day this results in 5.7 hours of charging at the lowest electricity price and 4.5 hours of discharging at the highest price. The price delta is considered in the revenue from price-responsive V2G charging.

Revenue calculations are based on a discharge-to-grid potential of 38.5 gigawatts in 2030, assuming a 15% adoption rate and charging at home and at work. Other parameters include the following:

- full-load hours of charging: 2,070
- full-load hours of discharging: 1,650
- interval length for each cycle to take place: 24 hours

[232] Timo Kern, Patrick Dossow, and Serafin von Roon, "Integrating bidirectionally chargeable electric vehicles into the electricity markets," *Energies* 13, no. 21, November 2020, https://doi.org/10.3390/en13215812.

run time per interval for charging: 5.7 hours at EUR 33 per megawatt hour

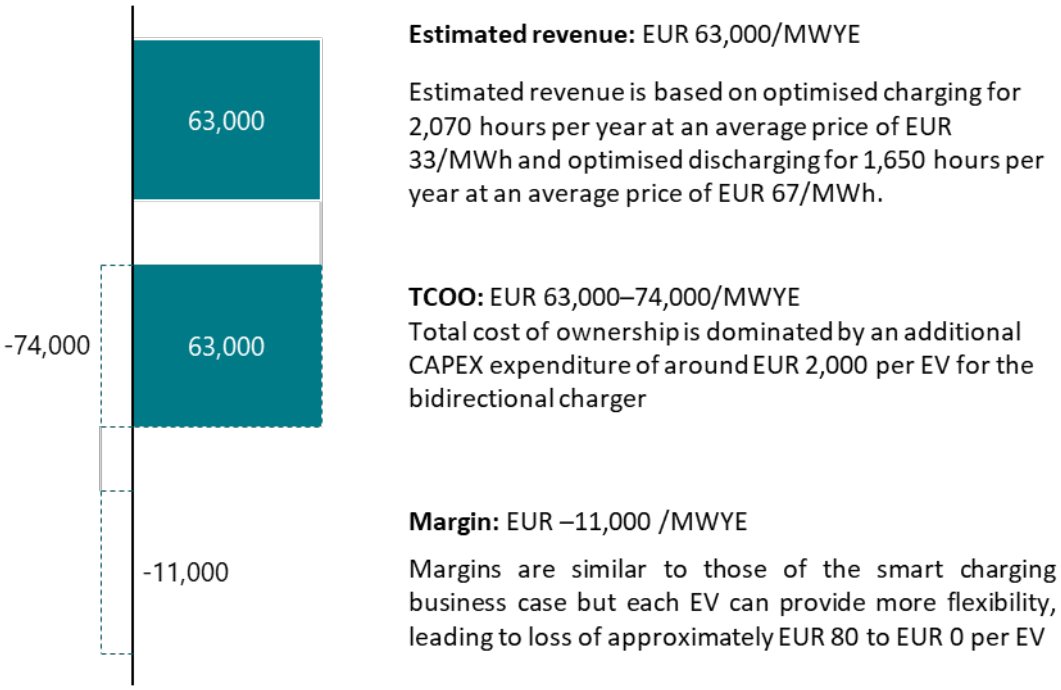
run time per interval for discharging: 4.5 hours EUR 67 per megawatt hour

Excluding taxes and fees, price-responsive bidirectional charging can create substantial savings for the user. It can create revenue streams for an aggregator through arbitrage trading, and its system impact is expected to be greater than that of smart charging. For one vehicle, an annual revenue of around EUR 340 a year is possible under these conditions. This number is based on arbitrage trading of power only; charging costs to satisfy mobility needs are not considered. On an aggregated level, the revenue calculation yields the following:

- average cost of charging: EUR 68,000 per megawatt hour
- average revenue from discharging: EUR 111,000 per megawatt hour
- comparison cost of charging for self-use: EUR 20,000 per megawatt hour
- estimated revenue: EUR 63,000 per megawatt year

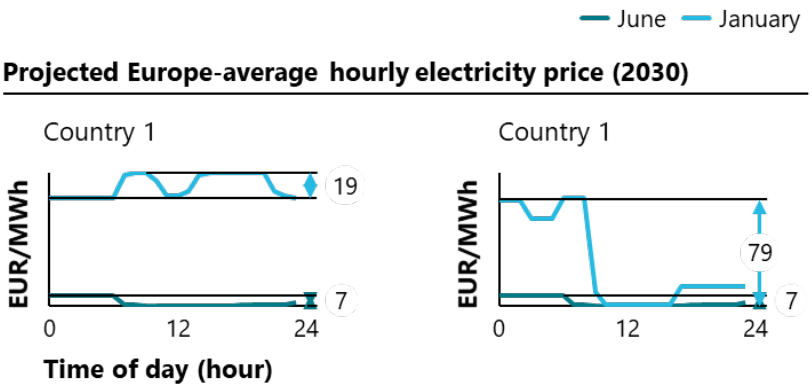
Figure 76 summarises revenue and costs, and also presents the case's margin. For V2G, this margin is negative.

Figure 76. Estimated revenue, TCOO and margin for V2G, EUR/MWYE



In this model, price can vary significantly, depending, for example, on the share of solar energy and electricity demand. The spread between the highest and lowest prices on a given day also has a strong influence profitability. Figure 77 shows the price spread of the same day in different seasons for two hypothetical countries.

Figure 77. Price spread for two hypothetical countries on days in June and January



Because the revenue for V2G depends on the battery capacity available for bidirectional charging and the underlying power system, variations are likely for different countries. Furthermore, potential rebound effects are possible; for example, the decreased cost for EV charging can affect driving patterns and journey length, which will impact the availability of EV capacity.

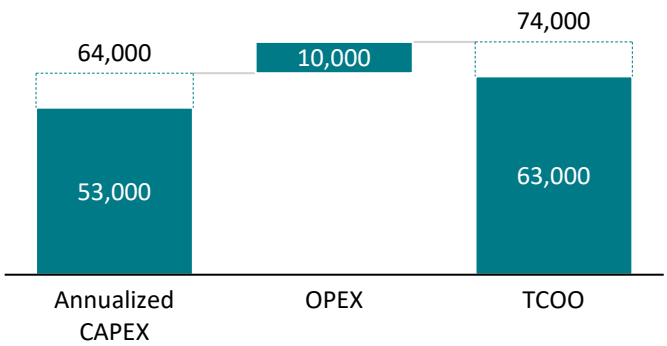
While the revenues look positive, this assessment is highly uncertain because it is difficult to estimate underlying power prices and because revenue estimates are simplified, focusing only on wholesale revenues and ignoring cannibalisation effects within and across business cases.

12.7.3 Total cost of ownership

The TCOO calculations in EUR/MWYE for price-responsive bidirectional charging are based on a discharge-to-grid potential of 38 gigawatts by 2030, assuming a 15% adoption rate and charging at home and at work. As long as V2G is in the pilot stage, TCOO is driven by CAPEX, particularly for bidirectional chargers and corresponding electronics. This analysis assumes substantial cost reductions for all V2G-specific components owing to learning rates and economies of scale. Consequently, the TCOOs for price-responsive bidirectional charging and V2G congestion management and ancillary services are highly uncertain.

Our parameterisation is done for one EV. Therefore, the annualised CAPEX and OPEX are scaled using the total number of EVs participating in this business case in 2030 divided by the adjustable capacity calculated for this business case. Figure 78 displays the total cost of ownership based on CAPEX and OPEX.

Figure 78. Total cost of ownership, EUR/MWYE



EVs, smart charging stations, station installation and smart meters are not considered in our CAPEX calculation as the analysis assumes they will already be part of the infrastructure by 2030. However,

as bidirectional-charging functionality is not a standard feature for charging stations, additional costs for bidirectional chargers are considered.

In the pilot phase, bidirectional charging stations cost about EUR 5,990. This analysis assumes the price will come down by about half once the technology is mature; the same cost reduction is assumed for bidirectional electronics and communication systems. Table 25 shows capital expenses incurred by price-responsive bidirectional charging that exceed the capital expenses of unidirectional chargers; the total CAPEX ranges between EUR 2,656 and EUR 3,166 over the car's lifetime.

Operating expenses – including scheduling, control, database, and operations and maintenance – are assumed to be EUR 48 per year per EV.

This analysis estimates medium to high challenges for V2G, largely because of initial high prices, but regular smart charging can also be an enabler for V2G, as once EV users become familiar with smart charging, they could be more likely to adopt V2G as well.

Table 25. Cost of flexibility for price-responsive bidirectional charging, in euros per EV

Capital expenses (CAPEX)	Cost range (euros)		Unit
	Minimum	Maximum	
Additional costs for smart, bidirectional charging station[233]	1,796	2,306	EUR/EV
Bidirectional electronics[234]	825	825	EUR/EV
Bidirectional communication system[235]	35.50	35.50	EUR/EV
Total CAPEX	**2,656**	**3,166**	**EUR/EV**

12.8 Business case: Congestion management and ancillary services using V2G

This business case addresses load shifting and bidirectional charging specifically for grid-balancing at the request of the grid operator or in market-based systems. Because of minimum capacity requirements for participation in an ancillary market, participation is feasible only if EV flexibility resources are pooled. Moreover, capacity is reserved in advance and separately from the provision of balancing power. Therefore, the service provider must ensure that the reserved capacity can actually be dispatched.

[233] Besser Laden, Wallbox Quasar – Bidirektionale Ladestation [Wallbox Quasar – Bidirectional charging station], accessed July 07, 2021, https://besserladen.de/produkt/wallbox-quasar-bidirektionale-ladestation/; and Innogy, FAQ - Häufig gestellte Fragen rund um Netzanschluss, Montage, Inbetriebnahme, Produkte, Abrechnung und Lieferung von Strom [FAQ – Frequently Asked Questions About Grid Connection, Assembly, Commissioning, Products, Billing, and Supply of Electricity].

[234] David Dallinger, Daniel Krampe, and Martin Wietschel, "Vehicle-to-grid regulation reserves based on a dynamic simulation of mobility behavior," *IEEE Transactions on Smart Grid* 2, no. 2, June 2011, https://doi.org/10.1109/TSG.2011.2131692.

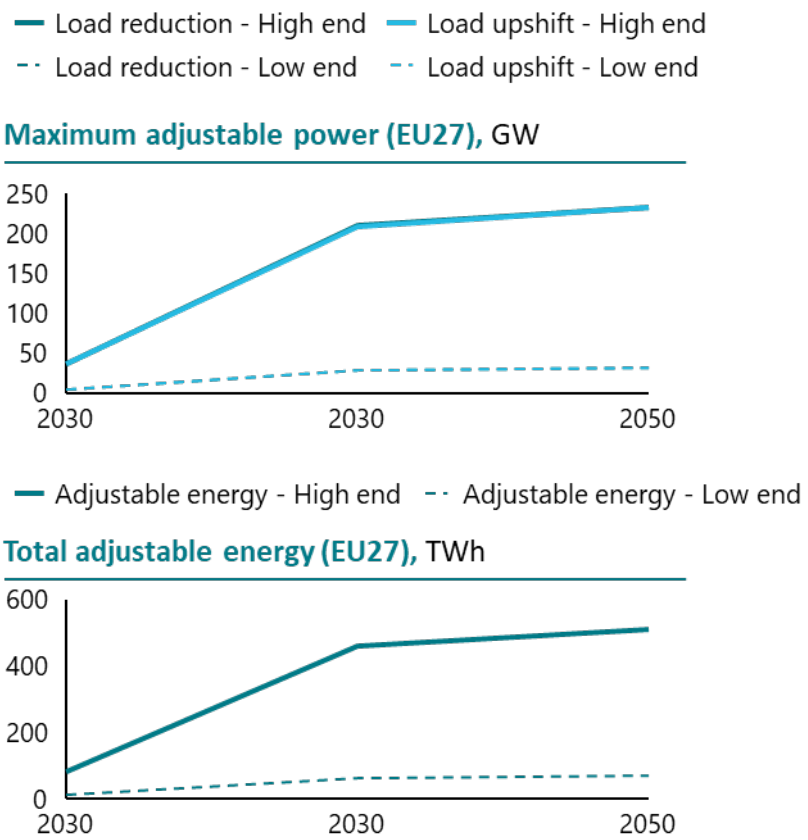
[235] Ibid.

12.8.1 Potential time frame

For this business case, more communication infrastructure and data exchange among parties is needed than for price-responsive bidirectional charging before adoption becomes widespread. Additionally, participation in ancillary services requires prequalification, or the formal approval that the capabilities assumed can indeed be provided by the asset of concern, at least of the aggregator pooling EV flexibility resources. Therefore, this analysis assumes adoption rates 10% to 15% lower than for price-responsive bidirectional charging.

As noted earlier in this Chapter, adjustable power is subdivided into load reduction and discharge-to-grid. To ensure the provision of a set amount of power, load reduction is determined by calculating the average availability for each hour of a day over the course of a week (average of the first hour of the day for each day of the week, average of the second hour of the day for each day of the week, etc.) multiplied by the total EV stock and the average charging and discharging capacity. The minimum average value is assumed as the upper barrier for the capacity that can be reserved for ancillary services, as shown in Figure 79.

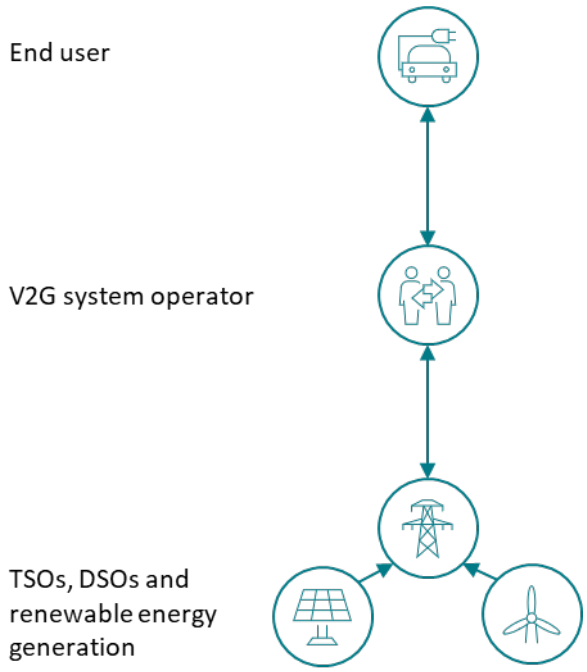
Figure 79. Impact of V2G congestion management and ancillary services flexibility on the energy system



12.8.2 Economic assessment

This section discusses the main players associated with the business case – that is, those expected to primarily implement it – and explores its economic viability for them. Figure 80 shows a schematic of the power and energy flow for this business case as well as the players relevant in each step.

Figure 80. Power and energy flow for the congestion management and ancillary services with V2G business case



The key stakeholders for this business case are end users (EV owners), V2G system operators and TSOs/DSOs.

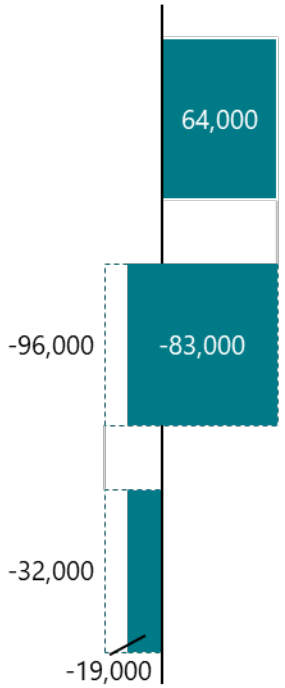
End users can expect benefits from this business case in the form of a lower consumption bill and revenues from bidirectional charging. They may be inconvenienced by the requirement that the EV be connected to the grid, and from part of the battery capacity being used for V2G.

The V2G system operator also benefits from this business case by monetising the flexibility capacity in EVs.

TSOs and DSOs can profit from reduced grid constraints, from the possibility to defer capital investments to resolve congestion, and from EVs participating in frequency reserve and thereby actively contributing to grid stability.

The operating margin from this business case is calculated from estimated revenue and total cost of ownership, as shown in Figure 81.

Figure 81. Estimated revenue, TCOO and margin of congestion management and ancillary services with V2G



Estimated revenue: EUR 64,000/MWYE
Estimated revenue is based on an assumed revenue of EUR 39,000/MW for FRR capacity reservations and EUR 58/MWh for energy delivery, with about 440 hours of activation per year.

TCOO: EUR 83,000 to EUR 96,000/MWYE
Total cost of ownership is again dominated by an additional CAPEX expenditure of around EUR 2,000 per EV for a bidirectional rather than unidirectional charger; however, cost per megawatt is higher because less capacity can be reserved for this case.

Margin: EUR –32,000 to EUR –19,000/MWYE
Margin, corresponding to EUR –133 to EUR –90 per year per EV, is highly uncertain due to unclear projections for FRR demand and price, while the bidirectional charger adds a significant onetime cost.

The calculation for this business case is based on secondary reserve data reported for Germany in 2019, which is used as a proxy since no model is available to predict secondary reserve data for 2030[236]. Parameters include the following:

- activated energy (aFRR, mFRR): 2,688 gigawatts per hour
- reserved capacity (aFRR, mFRR): 6,153 megawatts
- full-load hours: 437 hours
- associated cost for capacity reservation: EUR 239 million
- associated cost for activation: EUR 155 million

Based on the revenue for capacity reservation and delivery and the corresponding full-load hours assumed for this case, the annual revenue for one vehicle would be approximately EUR 230. If the EV is to be charged at wholesale prices (through optimised charging), the cost for charging the amount of energy needed based on the assumed full-load hours corresponds to EUR 51 a year, leading to net revenue of EUR 179 per EV per year. Charging costs to satisfy mobility needs are not considered.

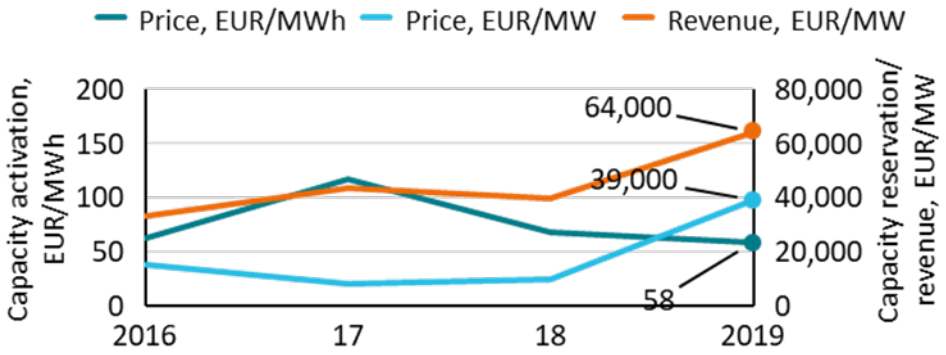
Aggregated revenue calculation yields the following:

- revenue from FRR capacity reservations: EUR 39,000 per megawatt
- revenue from FRR energy delivery: EUR 58 per megawatt hour
- estimated revenue: EUR 64,000 per megawatt year

Since 2016, capacity reservation prices in Germany have varied from around EUR 8,250 to EUR 39,000 per megawatt, and activation costs have ranged from EUR 62 to EUR 116. Revenue has varied from around EUR 33,000 to EUR 64,000 per megawatt, as shown in Figure 82.

[236] "Was ist Regelenergie?"

Figure 82. Recent historical prices on German balancing markets



Initially, V2G will compete with conventional (fossil fuel–based) assets for ancillary services, but it will eventually replace them. Prequalification and regulatory barriers hamper the uptake of V2G for ancillary services, and, as for the other V2G business case discussed, rebound effects are possible owing to the decreased cost of charging. Finally, the revenue calculation is made in an aggregated manner for all flexibility options participating in ancillary services. For this calculation, no additional costs – such as for the generation of electricity or for charging – were assumed.

12.8.3 Total cost of ownership

The TCOO calculations in EUR/MWYE for this business case are based on a discharge-to-grid potential of 24.58 gigawatts in 2030, assuming a 12.5% adoption rate corresponding to approximately 6.9 million EVs throughout Europe and charging at home and at work. As long as V2G is in the pilot stage, cost is driven by CAPEX, particularly for bidirectional chargers and corresponding electronics. This analysis assumes substantial cost reductions for all V2G-specific components reflecting learning rates and economies of scale. Consequently, the TCOO for congestion management and ancillary services with V2G is highly uncertain.

Our parameterisation is done for one EV. Therefore, the annualised CAPEX and OPEX are scaled using the total number of EVs participating in this business case in 2030 divided by the adjustable capacity calculated for this business case. EVs, smart charging stations, station installation and smart meters are not considered in our CAPEX calculation as the analysis assumes they will already be part of the infrastructure by 2030. However, as bidirectional-charging functionality is not a standard feature for charging stations, additional costs for a bidirectional charger are considered.

Table 26 shows this case's additional capital expenses compared with the capital expenses of unidirectional chargers; the total CAPEX ranges between EUR 2,656.50 and EUR 3,166.50 over the car's lifetime, or between approximately EUR 221 and EUR 264 a year.

Operating expenses – including scheduling, control, database, and operations and maintenance – are assumed to be EUR 48 a year per EV.

While cost per EV is the same for both V2G business cases, the number of EVs needed to supply 1 MW of flexibility capacity is different. As a result, the TCOO (expressed as EUR/MWYE) is different between the two busines cases.

Figure 83. Total cost of ownership, EUR/MWYE

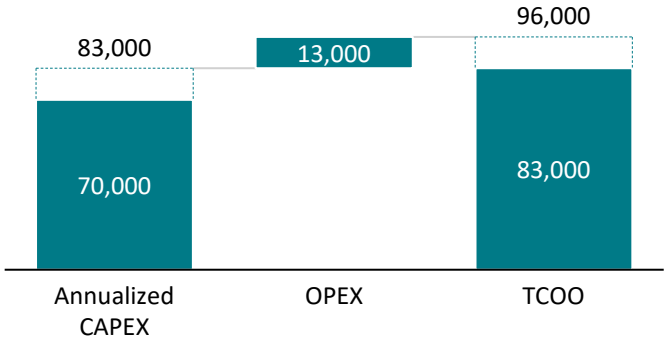


Table 26. Cost of flexibility for congestion management and ancillary services with V2G, in euros per EV

Capital expenses (CAPEX)	Cost range (euros)		Unit
	Minimum	Maximum	
Additional costs for smart, bidirectional charging station[237]	1,796	2,306	EUR/EV
Bidirectional electronics[238]	825	825	EUR/EV
Bidirectional communication system[239]	35.50	35.50	EUR/EV
Total CAPEX	**2,656**	**3,166**	**EUR/EV**

Cost varies according to the form of participation in a business case, including potential prequalification costs. The TCOO in EUR/MWYE for this business case – congestion management and ancillary services using V2G – is higher than the TCOO for the other business case in the V2G use case, price-responsive bidirectional charging, because this analysis assumes that the capacity that can be reserved for the participation of EVs in ancillary services is limited and substantially lower than the capacity available for price-responsive V2G charging.

As prices for bidirectional chargers are currently high, V2G profitability may encounter medium to high challenges.

[237] besser laden. Wallbox Quasar – Bidirektionale Ladestation. [July 07, 2021]; FAQ - Häufig gestellte Fragen rund um Netzanschluss, Montage, Inbetriebnahme, Produkte, Abrechnung und Lieferung von Strom; Available from: https://dressel-egu.de/fileadmin/DRESSEL/Dokumente/FAQs_emone.pdf.

[238] Dallinger, Krampe, Wietschel M. "Vehicle-to-Grid Regulation Reserves Based on a Dynamic Simulation of Mobility Behavior."

[239] Ibid.

13 Analysis of business cases

The increasing penetration of variable renewables will require increased flexibility from the European power system – a natural result of renewable energy sources' inability to provide a consistent baseload owing to the variability and unpredictability of sun exposure and wind currents. Power flexibility allows wholesale markets to align demand and supply within a day and beyond, ancillary services to stabilise the grid in one to four hours, and TSOs and DSOs to manage congestion and local grid limitations.

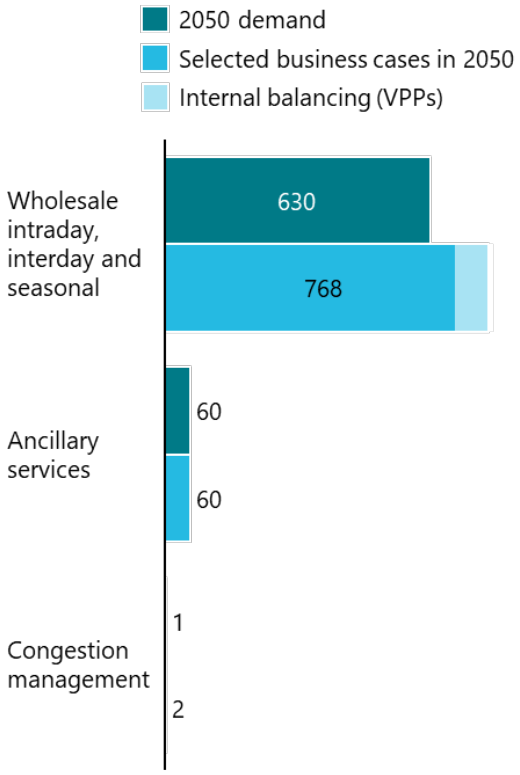
Digital and digitally enabled power flexibility can be an effective alternative to hardware-enabled flexibility, and trading flexibility in the wholesale interday market is key to handling extended periods of low production from variable renewables.

13.1 Overview of business cases

13.1.1 Projected demand

The business cases for digital power flexibility analysed in this report are expected to exceed flexibility needs by 2050. The business cases for intraday flexibility are expected to have the greatest applicability, and those for interday and seasonal demands are expected to have limited applicability. Figure 12.1 shows the projected demand for flexibility by 2050 and the capacity from selected business cases for various flexibility types. This analysis incorporates some simplifying assumptions to arrive at the projected flexibility demand versus flexibility provided. These assumptions are described in detail in Section 12.2, "Digital solutions applied: A scenario for 2050," and the "Potential time frame" sections of the preceding business case Chapters.

Figure 84. Projected flexible capacity (gigawatts)[240]

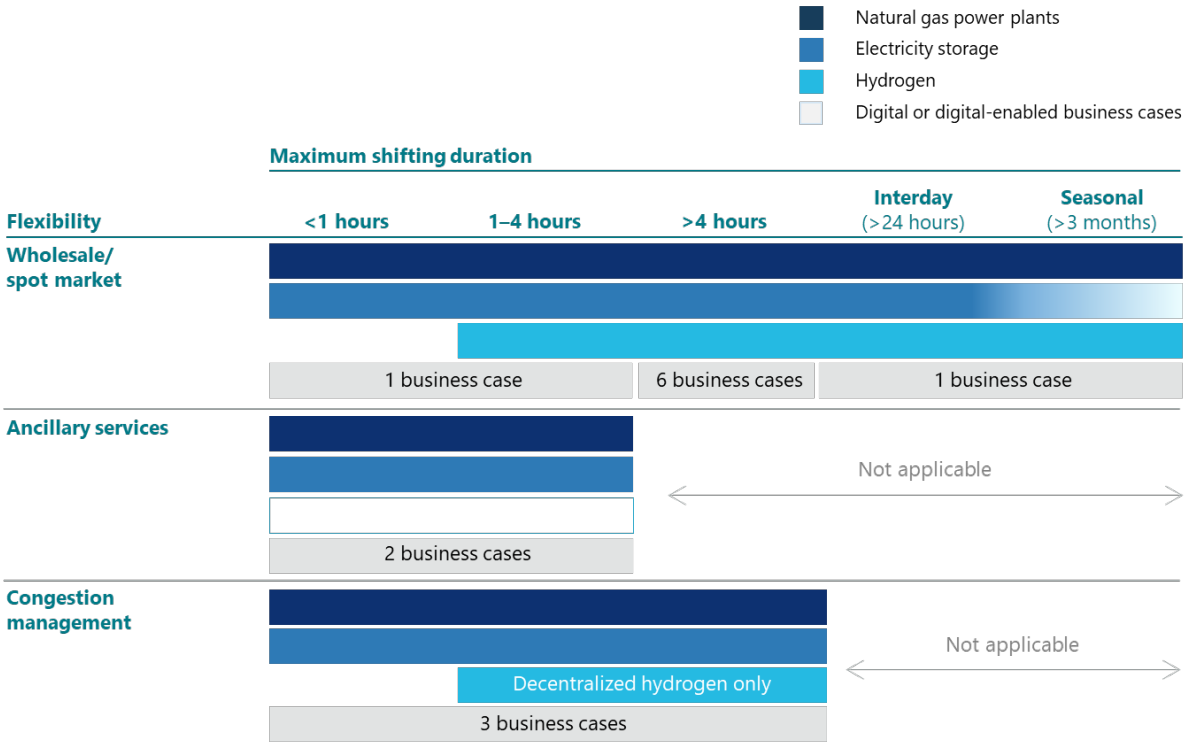


Each case is assigned to one or more markets in a way that prevents double-counting, with a focus on matching ancillary and congestion markets based on market priority. Meeting wholesale flexibility demand is a third priority after providing ancillary services and congestion management.

In addition to the digital power–flexibility cases examined in this study, the European power system may adopt non-digital flexibility options like gas power plants, electricity storage (utility-scale batteries) and hydrogen, as shown in Figure 85, because digital flexibility options are limited in terms of interday and seasonal applicability. Non-digital flexibility options fell outside the scope of this effort.

[240] This includes 80 gigawatts of internal balancing for virtual power plants, which does not necessarily (fully) count against the flexibility target.

Figure 85. Maximum shifting duration for natural gas power plants, electricity storage, hydrogen and digital (enabled) business cases or flexibility solutions



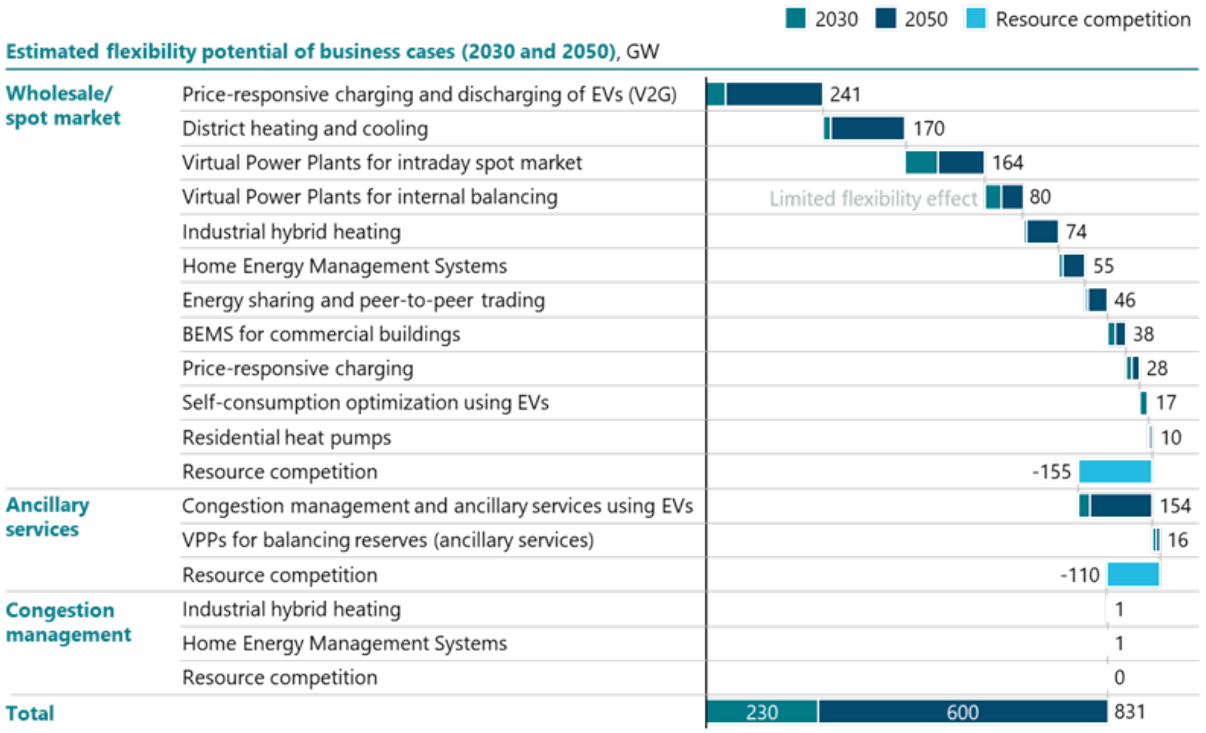
13.1.2 Impact at scale

The analysed business cases were mapped against the required capacity for each of the three flexibility types (wholesale/spot market, ancillary services, and congestion management) to create a perspective of the potential solutions for achieving impact at scale.

Key flexibility options for the wholesale/spot market are EVs for both one-way and bidirectional responsive charging, VPPs, and district heating and cooling. The largest potential for ancillary services is linked to EVs, followed by VPPs, which provide dispatchable RES without batteries. Congestion management can be supported by industrial load control, BEMS, and HEMS, because of their spatial distribution in TSO and DSO grids.

Figure 86 shows the digital solutions for the three flexibility types, ranked by estimated capacity in 2030 and 2050.

Figure 86. Capacity of digital solutions by flexibility type



Adjustments were applied for business cases that are in direct competition for resources and therefore unlikely to coexist at maximum estimated capacity, such as EV batteries, which can be applied to only one of the four business cases at a time. The approach to these adjustments are elaborated later in this Chapter.

13.1.3 Properties

This section describes the main overlaps, differences, and gaps in the capabilities of the analysed digital flexibility solutions.

A detailed overview of flexibility properties for each of the business cases is shown in Figure 87. For digital flexibility solutions to compete with non-digital ones, full compatibility is required regarding flexibility in shifting direction and in shifting duration, and regarding availability.

Figure 87. Overview of flexibility properties by business case[241]

✓ Feasible within business case scope
✗ Not feasible within business case scope
(✓) Feasible depending on set-up, outside scope of business case

		Max shifting duration					Shifting direction		Daytime availability			
Business case	Flexibility type	<1 hours	1-4 hours	>4 hours	Interday (>24 hours)	Seasonal (>3 months)	Upward	Down-ward	Night	Morning	Midday	Evening
3.1: VPPs for intraday flexibility	Wholesale	✓	✓	✓	✗	✗	✓	✓	✓	✓	✓	✓
3.2: VPPs for balancing reserves (ancillary services)	Ancillary services	✓	✓	✓	✗	✗	✓	✓	✓	✓	✓	✓
3.5: VPPs for internal balancing	Wholesale	✓	✓	✓	✗	✗	✓	✓	✓	✓	✓	✓
4.1: Energy sharing communities and P2P	Wholesale	✓	✓	✓	✗	✗	✓	✓	✓	✓	✓	✓
4.4: District heating and cooling	Wholesale	✓	✓	✓	(✓)	(✓)	✓	✓	✓	✓	✓	✓
5.1: BEMS for commercial buildings	Wholesale	✓	✓	✗	✗	✗	✓	✓	✗	✓	✓	✓
6.2: Industrial hybrid heating	Wholesale/ congestion	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
7.1: Heat pumps for residential buildings	Wholesale	✓	✓	✗	✗	✗	✓	✓	✓	✓	✓	✓
7.3: HEMS for residential buildings	Wholesale	✓	✓	✓	✗	✗	✓	✓	✓	✓	✓	✓
8.1: Price/incentive-responsive charging of EVs	Wholesale	✓	✓	✓	✗	✗	✓	✓	✓	✓	✓	✓
8.3: Self consumption optimization using EVs	Wholesale	✓	✓	✓	✗	✗	✓	✓	✗	✓	✓	✗
9.1: Price/incentive-responsive charging and discharging of EVs	Wholesale	✓	✓	✓	✗	✗	✓	✓	✓	✓	✓	✓
9.2: Congestion management and ancillary services using EVs	Ancillary services	✓	✓	✓	✗	✗	✓	✓	✓	✓	✓	✓

This overview shows that many business cases address the intraday spot market, while only one provides interday flexibility. This analysis does not suggest significant gaps in flexibility directionality. All of these digital solutions are available in all seasons and across all regions of the European Union.

13.1.4 Competition

Digital flexibility solutions may compete for the same business model or for the same resources. As a consequence, they are unlikely to coexist at projected maximum capacity, and adjustments could be made to resize the projected capacity for respective business cases (an illustrative example would be for one-third of EVs to provide ancillary services while two-thirds of EVs would be used for wholesale intraday flexibility).

Specific instances of competition for the same business model by business cases analysed in this report include the following:

VPPs and energy communities. VPPs and energy communities are in direct competition for the aggregated dispatchable capacity business model, while competition for resources is negligible (that is, there is competition for CHP through pumped hydro, but not for batteries, because solar and wind are excluded from energy communities). Analysis indicates that both VPPs and energy-sharing communities can coexist to meet flexibility demand. As a result, no adjustments were made to the capacities available from the VPP and energy-communities business cases.

Stationary and EV batteries. Stationary and EV batteries affect four EV business cases, the stationary residential battery business cases of energy communities, and the residential home energy

[241] Upward: consumption down, generation up. Downward: consumption up, generation down. Daytime availability feasible for the energy sharing and peer-to-peer trading business case assuming communities generate power from both solar and wind.

management systems business case. Battery electric vehicles and stationary batteries could take largely similar roles when connected to the grid. As this competition is for the business model and not for resources, the available capacity has not been adjusted.

Competition for resources by business cases analysed in this report include the following specific instances:

Battery electric vehicles. Battery electric vehicles are the focus of four of the business cases discussed: price-responsive charging, self-consumption optimisation, price-responsive charging and discharging for V2G, and congestion management and ancillary services. In this study, EV battery capacity has been divided over the four business case applications based on the most efficient use of EVs per gigawatt of flexibility (which is driven by, among other factors, availability of the EV to be connected to the grid) to provide the overall largest grid flexibility capacity. In practice, the business case profitability and ability to scale a specific application will likely determine how much capacity is available for each business case.

Residential batteries. Residential batteries drive HEMS and energy-sharing communities. Use of stationary residential batteries to optimise self-consumption in individual households is an opposing application to optimising for energy communities, where self-consumption is deprioritised over community benefits. As such, residential stationary batteries will be used for one of the two applications only. This competition for resources is reflected in the projected available capacities of the respective business cases based on the 2016 CE Delft study of battery applications cited earlier in this report[242].

13.2 Digital solutions applied: A scenario for 2050

The following scenario illustrates how results from this study could help to provide sufficient flexibility by 2050. This scenario is not necessarily optimal; its main assumptions and simplifications are listed in Section 12.2.1.

A merit order, or ranking, has been constructed for each of the flexibility types based on margin (estimated revenue minus total cost of ownership) and available capacity in light of competing cases. Revenue estimations are provided in detail in the respective business case Chapters.

Figure 88, Figure 89 and Figure 90 show how the available digital flexibility solutions compare to meet the required level of capacity (vertical dashed line) with estimated margin before taxes and other costs.

A high-level analysis concludes that wholesale and ancillary services cannot be fully provided through digital flexibility solutions in a profitable manner. For example, while business case 9.2 (congestion management and ancillary services using EVs) could provide sufficient capacity, analysis suggests a possibly negative profitability margin.

[242] Kampman, Blommerde, and Afman, The Potential of Energy Citizens in the European Union.

Figure 88. Merit order of business cases (represented by their numbers, as designated in Table 2) for estimated spot market margin, in euros per megawatt-year

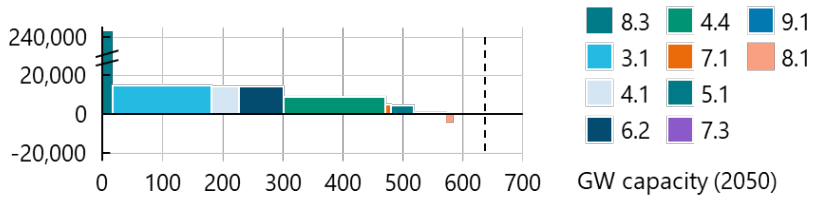


Figure 89. Merit order for estimated ancillary services margin, in euros per megawatt-year

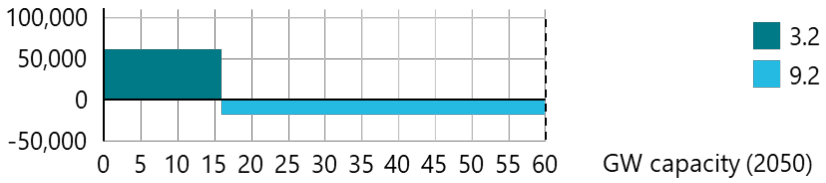
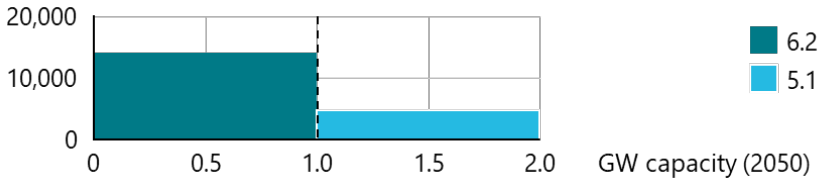


Figure 90. Merit order for estimated congestion-management margin, in euros per megawatt-year



13.2.1 Possible composition of power-flexibility system

Business cases with decreasing margins were selected until the three flexibility targets for 2050 demand were met or no additional capacity at positive margin was available. In the case of wholesale power, this process leaves a potential gap of about 85 gigawatts of flexibility to be filled by non-digital flexibility sources; for ancillary services, a gap of 44 gigawatts must be filled by non-digital flexibility sources.

This scenario, constructed purely to study the possible implications of integrating digital power flexibility solutions and the possible limitations of each system, makes the following simplifications:

The margin estimate does not consider fees, taxes or other costs.

Differences in upward and downward demand are not considered.

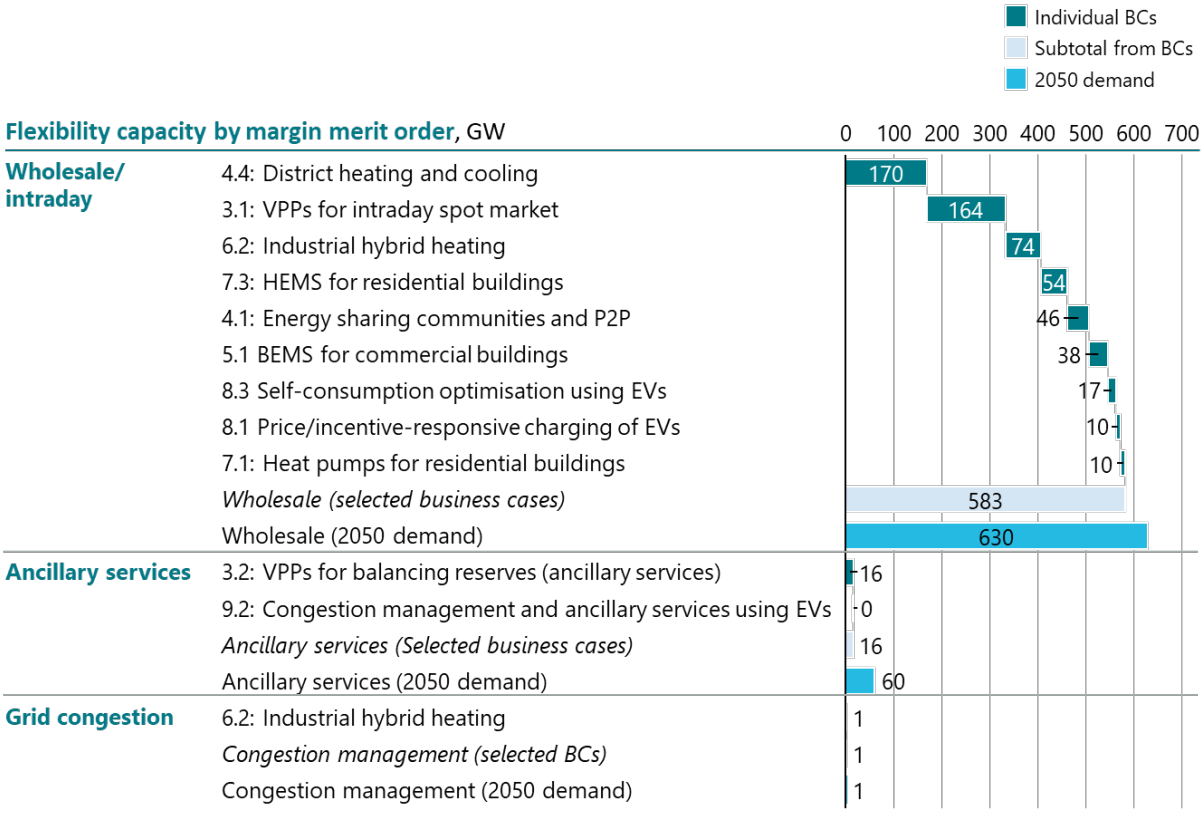
Maximum shiftable duration of flexibility is not considered, and intraday and interday are not treated separately.

No spatial requirements for congestion management were considered in any way.

Non-digital flexibility solutions were not considered.

Figure 91 shows the contributions from individual business cases to meet overall demand for each flexibility type.

Figure 91. Flexibility-capacity contribution to scenario



In this scenario, wholesale flexibility demand can largely be met by a combination of EVs, VPPs and energy communities, and district heating and cooling. The remaining 45 gigawatts could be covered using non-digital power-flexibility sources.

Note that the three EV business cases compete for the same fleet of cars. Based on a need of 44 gigawatts for ancillary services, the remaining fleet is divided over the self-consumption optimisation and price-responsive charging business cases.

Ancillary services can partially be provided by VPPs, though EVs will not supplement the VPPs owing to their projected negative margin. About 45 gigawatts of non-digital power-flexibility options will be needed to meet a total 60-gigawatt ancillary services demand by 2050. Grid congestion could be mitigated fully by industrial load flexibility leveraging hybrid heating systems.

From the list of business cases included in this scenario, the following gaps and overlaps have been observed based on the specific assumptions of this scenario (see also Figure 92), the individual technologies and the business cases selected:

Based on margin merit order, the projected 2050 demand for all three flexibility types can be met with positive operating margins (before fees, taxes and other costs).

Industrial hybrid heating is the only digital business case providing flexibility beyond 24 hours if needed. This capacity can be used for both congestion management (through demand-side response) or for the spot market.

The selected business cases cover availability across all seasons and in both flexibility directions (upward and downward).

Figure 92. Overview of flexibility properties for business cases included in the scenario

✓ Feasible within business case scope
✗ Not feasible within business case scope
(✓) Feasible depending on set-up, outside scope of business case

			Max shifting duration					Shifting direction		Daytime availability			
Business case #	Business case	Flexibility type	< 1 hours	1-4 hours	> 4 hours	Interday (>24 hours)	Seasonal (>3 months)	Upward[1]	Down-ward[2]	Night	Morning	Midday	Evening
3.1	VPPs for intraday flexibility	Wholesale	✓	✓	✓	✗	✗	✓	✓	✓	✓	✓	✓
3.2	VPPs for balancing reserves (services)	Ancillary services	✓	✓	✓	✗	✗	✓	✓	✓	✓	✓	✓
4.1	Energy sharing communities and P2P	Wholesale	✓	✓	✓	✗	✗	✓	✓	✓	✓	✓	✓
4.4	District heating and cooling	Wholesale	✓	✓	✓	(✓)	(✓)	✓	✓	✓	✓	✓	✓
6.2	Industrial hybrid heating	Wholesale/ congestion	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
7.1	Heat pumps for residential buildings	Wholesale/ congestion	✓	✓	✗	✗	✗	✓	✓	✓	✓	✓	✓
8.1	Price/incentive-responsive charging of EVs	Wholesale	✓	✓	✓	✗	✗	✓	✓	✓	✓	✓	✓
8.3	Self consumption optimization using EVs	Wholesale	✓	✓	✓	✗	✗	✓	✓	✗	✓	✓	✗
9.2	Congestion management and ancillary services using EVs	Ancillary services	✓	✓	✓	✗	✗	✓	✓	✓	✓	✓	✓

14 What it will take to get there

Changes required could include but are not limited to the following:

A EUR 40 billion capital investment would provide flexibility to the European power system. This estimate is based on the capital expenses and the projected capacity of the selected business cases. It assumes underlying infrastructure is in place; for example, EV vehicles and dispatchable renewable generation must be present but may require aggregation to provide flexibility.

Hybrid heating systems could be upgraded for low- and medium-temperature heating at approximately 3,000 industrial sites (100% of suitable sites).

About 60% of all dispatchable renewable energy, or 165 gigawatts, would be aggregated into VPPs.

Approximately 3,400 district heating networks (50% of total residential heat demand) would offer flexibility through heat storage and would participate in flexibility markets. This estimate is based on Heat Roadmap Europe 4 and forms the foundation for district heating and cooling flexibility potential.[243]

About 59 million EVs would use smart charging, and 7 million, or 35% of projected EVs by 2050, would participate in vehicle-to-grid flexibility activities

[243] Paardekooper et al., *Heat Roadmap Europe 4.*

15 Data-sharing frameworks

This Chapter analyses the relevance of digital solutions as enablers of flexibility markets, with a focus on data sharing. The first sections explore the frameworks being developed by various international consortia for best-practice data-sharing, and later sections evaluate the use cases covered in this report against the varying dimensions of a relevant data-sharing framework, or infrastructure.

Data-sharing frameworks are a set of guidelines and protocols designed to ensure that stakeholders can share data securely and seamlessly. These standards and compliance mechanisms, developed by not-for-profit member associations, set the bar for data-sharing use cases across industries. They are still in early stages, but if adopted, they have the potential to improve data-sharing mechanisms, which are currently partly manual, less secure, slower, and not interoperable across platforms. These frameworks may add value to the European Union's economy and to its economic recovery from the COVID-19 pandemic[244], given their potential for innovation and job creation, as well as their contribution to the efficiency of industries across all sectors.

Data-sharing frameworks could be important to the energy sector for the following reasons:

The development of new business models. New business models could be developed as systems become less centralised and more distributed.

The integration of renewables into power systems. To meet the Green Deal's target that Europe be climate-neutral by 2050, electricity grids must be "smart" and operate economically. Seamless and efficient information exchange is necessary at many stages and among an increasing number of stakeholders, including power generators, TSOs, DSOs, consumers, and so forth[245].

Real-time data exchange for multiple applications. Real-time data exchange, from EV charging optimisation (communicating with the grid so that EVs can charge when electricity is cheap and cleanest) to connecting small producers with electricity markets, for example, would improve the efficiency, flexibility and resiliency of the power market.

Flexibility to handle the market's increasing volatility. The penetration of intermittent renewable electricity sources will enhance flexibility to handle increasing volatility.

As shown in Figure 93, a fully functioning data-sharing infrastructure consists of up to four elements[246]:

The *data space* is a virtual data-integration concept for data stored at the source in which participants provide their data resources and computing services in a standardised manner.

The *data ecosystem* is made up of consumers and companies that produce or provide data and other advanced smart services such as AI, analytics and automation.

Federation services ensure trust between participants, make data searchable, discoverable and consumable, and provide means for data sovereignty in a distributed environment. These services include: (1) identity and trust, which consist of authentication, authorisation, credential management and decentralised identity management; (2) data sovereignty services, which enable

[244] European Commission, "Recovery plan for Europe," Europa, n.d., https://ec.europa.eu/info/strategy/recovery-plan-europe_en.

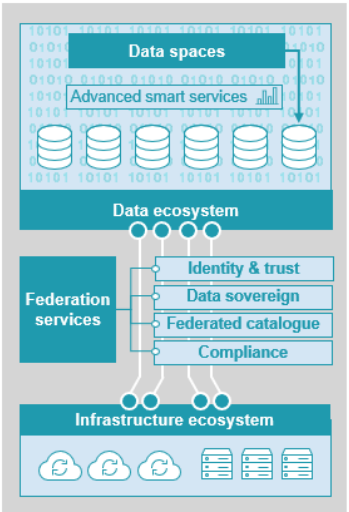
[245] ENTSO-E, "Common information model," n.d., https://www.entsoe.eu/digital/common-information-model/.

[246] Gaia-X, *Gaia-X Architecture Document*, April 2021, https://www.gaia-x.eu/sites/default/files/2021-05/Gaia-X_Architecture_Document_2103.pdf.

the enforcement of data usage policies; (3) the federated catalogue, which constitutes the central repository that enables providers to select and discover data; and (4) compliance, which includes mechanisms to ensure adherence to policy in areas such as security and privacy

The *infrastructure ecosystem* consists of consumers and providers of services including storage, computing capacity and networking power.

Figure 93. Best-practice data-sharing infrastructure elements



Focused Covered

		EU Data Spaces	IDS	GAIA-X	DSC
Data space		●	●	○	○
Data ecosystem			●	○	
Federation services	Identity and trust		●	○	●
	Data sovereign services		●	○	
	Federated catalogue		○	●	
	Compliance		○	●	
Infrastructure ecosystem				●	

15.1 Framework initiatives

Several initiatives have sprung up over the past few years to allow for safe and efficient data exchange. Although each initiative focuses on a different element of the required data-sharing infrastructure, they work in parallel to arrive at the best solutions for addressing various parts of the broader framework. Some of these initiatives overlap, but the underlying principle is to create synergies that allow them to build on one another. In alphabetical order, with no judgement on the mandates of the initiatives, they are described in the following text.

15.1.1 Data Sharing Coalition

The Data Sharing Coalition, a collaboration among more than four dozen international organisations, explores and defines generic agreements on a wide range of topics relevant to cross-sectoral data sharing, including technical standards, data semantics, legal agreements and trustworthy and reusable digital identities[247]. These agreements will be captured in a generic trust framework and governed by a common governing body consisting of coalition participants.

[247] Data Sharing Coalition, "Unlocking the true value of data," n.d., https://datasharingcoalition.eu/about-the-data-sharing-coalition/.

15.1.2 EU common data spaces

The EU common data spaces initiative aims to create a single market for data, allowing safe usage and flow of data from public bodies, businesses and citizens for research and the common good[248]. Its objective is to enhance the use of data in society and in the economy by lowering the transaction costs caused by current technical barriers. Nine data spaces are being created initially; these data spaces are in the health, industrial and manufacturing, agriculture, finance, mobility, Green Deal, energy, public administration and skills sectors.

Within this initiative, sponsored by the EU funding instruments Digital Europe Programme and Connecting Europe Facility, a formal expert group called the European Data Innovation Board will facilitate the creation of best practices for data spaces. A competent authority designated by the EU's member states will be responsible for monitoring compliance.

15.1.3 Gaia-X

Gaia-X, co-founded by Fraunhofer-Gesellschaft, the nonprofit International Data Spaces Association (IDSA) and the European cloud provider association CISPE, focuses on sovereign cloud services and infrastructure. It delivers an infrastructure for secure, trustworthy data-sharing across a multitude of individual platforms, it monitors compliance, enables interoperability and portability, and allows multiple databases to function as one[249]. Gaia-X has 22 founding members (11 from France, 11 from Germany).

15.1.4 International Data Spaces

International Data Spaces (IDS) is an initiative of the IDSA, a coalition of more than 130 member companies representing dozens of industry sectors and based in 22 countries across Europe and the world[250]. IDSA formally cooperates with at least nine international initiatives, and is part of the European Commission's Strategic Value Chain of the Industrial IoT and Digitising European Industry (DEI).

IDS aims to develop a reference architecture for international data spaces to enable open, transparent and self-determined data exchange. It focuses primarily on the data ecosystem, on security and on data sovereignty by ensuring standardisation.

15.2 Data-sharing pilots

Data-sharing initiatives are relatively young, and their application in the industry is largely still in the pilot phase. For example, in the energy sector, Gaia-X is developing pilots with the following characteristics:

- They use data from critical infrastructure for new business models.
- They use municipal open data for new business models in the energy industry.
- They develop community-level intelligent energy aggregators.
- They create intelligent edge data centres to support green-energy production plants that contribute to climate protection.
- They develop machine-learning redispatch 3.0 techniques to avoid grid collapse.

[248] "Common European data spaces," Real-time linked dataspaces, December 2021, http://dataspaces.info/common-european-data-spaces/#page-content.

[249] Gaia-X, "What is Gaia-X?," n.d., https://www.data-infrastructure.eu/GAIAX/Navigation/EN/Home/home.html.

[250] International Data Spaces Association (IDSA), "International data spaces: The future of the data economy is here," n.d., https://internationaldataspaces.org.

- They optimise the services and marketing of decentralised renewable energy generators.
- They bet on decentralised energy-trading infrastructure and industrial and residential energy agents to ensure smart, privacy-preserving coordination of energy supply and demand.
- They link plants, data and algorithms, from core market data to the aggregation of decentralised energy plants.

15.3 Data-sharing platforms in the energy sector

Similar initiatives to provide data transparency in a standardised way have already been implemented in other areas and have yielded positive results.

ENTSO-E, or the European Network of Transmission System Operators for Electricity, for example, was formed in 2008 by 32 core members and approximately 40 remote members. Governed by an assembly representing 42 TSOs and a board consisting of 12 elected members, ENTSO-E is devoted to the central collection and publication of data from the energy sector. It serves generators, retailers and traders by providing data transparency. ENTSO-E has had a positive impact on the economy; for example, its activities have levelled the playing field between small and large actors and have combatted climate change)[251].

Within ENTSO-E, a market information aggregator integrates information from most European TSOs, DSOs, power exchanges, larger-generation companies and merchant link operators[252]. Then, data is published on load, generation, transmission, balancing, outages, congestion management and more.

15.4 Digital maturity of use cases from the perspective of data-sharing frameworks

To analyse the maturity of digital solutions, it is helpful to evaluate uses cases from the perspective of data-sharing frameworks. Given its focus on the data environment, security and data resilience, and given its consolidated state, the IDS framework could serve as a suitable reference for an evaluation.

15.4.1 Strategic requirements of the IDS framework

IDSA's stated objective is to create data-sharing platforms that meet the following strategic requirements[253]:

Trust. An independent certification body or authority evaluates and certifies participants before they are granted access to the trusted data-sharing infrastructure.

Security and data resilience. Apart from architectural specifications, security is ensured mainly by the evaluation and certification of each technical component used in the space. In relation to data resilience, usage restriction information is attached to the data itself before it is transferred to a data consumer, and the data consumer may use the data only if it fully accepts the data owner's usage policy.

[251] European Commission, "A review of the ENTSO-E Transparency Platform," Europa, December 2007, https://ec.europa.eu/energy/sites/ener/files/documents/review_of_the_entso_e_plattform.pdf.

[252] ENTSO-E, "Central transparency platform: Implementation guide for European platforms," December 15, 2020, https://eepublicdownloads.entsoe.eu/clean-documents/EDI/Library/Central_Transparency_Platform___IG_for_European_Platforms_v1.0.pdf.

[253] Boris Otto et al., *Reference Architecture Model*, Version 3.0, International Data Spaces Association, April 2019, https://internationaldataspaces.org/wp-content/uploads/IDS-Reference-Architecture-Model-3.0-2019.pdf.

Data ecosystem. This ecosystem does not require central data-storage capabilities. Instead, it pursues the idea of decentralised data storage, which means that data physically remains with the respective data owner until it is transferred to a trusted party. Brokers in the ecosystem enable a comprehensive real-time data search.

Standardised interoperability. Every user or participant connected with the system can communicate with every other participant or component in the ecosystem. Standardised interoperability is subject to data security standards.

Value-adding apps. Apps can be developed to add services on top of pure data exchange. Services might include data processing and analytics.

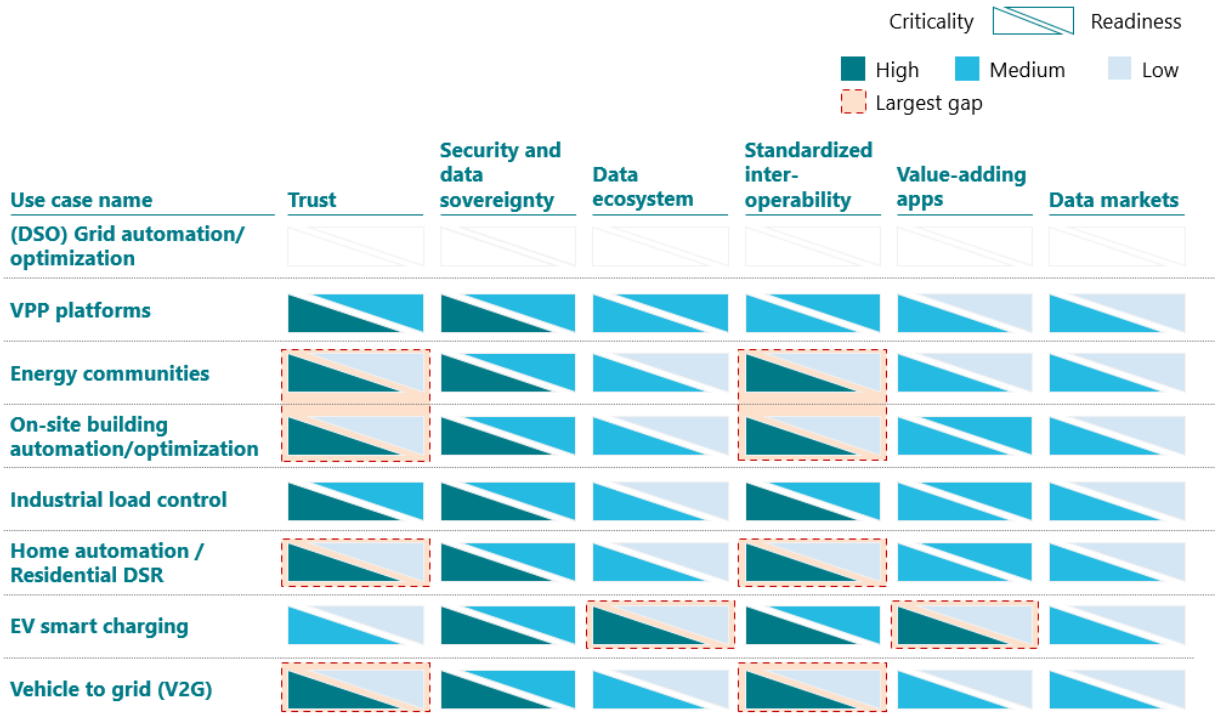
Data markets. IDS fosters new business models for novel, data-driven services that make use of data apps by providing clearing mechanisms and billing functions, and by creating domain-specific broker solutions and marketplaces.

15.4.2 Evaluation of use cases with respect to data-sharing requirements

To test the maturity of data-sharing frameworks in the power sector, use cases can be evaluated with respect to IDS's strategic requirements.

Figure 94 summarises the criticality and readiness of the strategic requirements identified in IDS for the prioritised use cases.

Figure 94. Overview of criticality and readiness for selected infrastructure and enablers aspects[254]



15.5 Bottlenecks

Some impediments to the satisfaction of data-sharing strategic requirements have been identified:

Lack of a centralised certification body across the European Union. Currently no organisation or branch of government certifies parties within the energy data space across the European Union; centralisation at the European level might be helpful.

Need for regulators to consider approach to innovative use cases. For innovative use cases such as energy communities, regulation is limited in most member states, and where it exists, it is at a more conceptual stage.

Expensive and complex security mechanisms. User-friendly and cost-efficient ways to introduce security and data sovereignty are key to ensuring adoption.

Lack of standardisation. Interoperability is a major industry barrier. For example, some systems are not compatible, and the cost to customers for switching is high. Interoperability challenges are especially evident in applications such as industrial load control, where a large number of potential assets are involved. At present, software for appliances such as electric heat pumps offers limited interoperability

[11] High criticality = the use case or business case's success requires the full application of guidelines; medium criticality = the use case or business case's success is feasible with partial compliance to the guidelines; low criticality = the use case or business case's success is not hindered by the application of guidelines. High readiness = existing solutions (e.g. technology, standards, product) meet all guidelines; medium readiness = existing solutions meet some of the guidelines; low readiness = existing solutions are in a very early stage and do not meet any or most guidelines.

16 Regulations and enabling framework

16.1 Requirements, gaps and enablers

The assessment of current regulations and the enabling framework is use-case- or business-case-specific. Recommendations are given for use or business cases and are summarised to indicate overarching aspects and issues that facilitate and foster the usage and implementation of flexibility business cases. The main required technologies and digital infrastructure, including standardisation, are assessed and key current regulations regarding market design and customer participation are described. Based on technical requirements, identified gaps and enablers for the use or business cases, recommendations are given for future market designs and increased participation.

16.1.1 Distributed energy resource management systems

16.1.1.1 Technical aspects

To enable financial transactions, thousands – perhaps millions – of DER connections from an increasingly large vendor landscape must be integrated safely and reliably for real-time operations, and millions of customer accounts must be integrated to enable financial transactions. Operational forecasting of demand and supply gives grid operators the opportunity to increase the grid's efficiency, but requires including additional DER in operational controls, which in turn requires changes to data-quality and data-integrity standards such as connectivity model corrections.

Transport-layer security is still lacking in DER systems, and existing security systems are costly, which is slowing the adoption of advanced distribution management systems and distributed energy resource management systems (DERMS). Maintenance expertise is required to run systems efficiently.

16.1.1.2 Current regulations

If regulations allowed various stakeholders easy and standardised participation, with clearly defined roles and related processes, high transaction costs could be avoided, especially for small-scale units. Member states have lowered capacity thresholds for small-scale units in congestion management and other ancillary-services markets, but in many states implementation and participation levels remain low. The regulation of the internal electricity market addresses participation and bid size for all kinds of flexibility options, but does not incentivise the activation and participation of these resources. DSOs are not always required to use DERMS, and the recognition of DERMS as a non-wires alternative is not a given. Third-party access to grid data and other information to optimise grid operation at the distribution level is also lacking.

16.1.1.3 Future designs and factors driving participation

A safe and trustworthy data framework, high data quality and data consistency based on hybrid centralised and distributed intelligence are necessary for more autonomous decision-making regarding the use of various power-generation and flexibility assets. The implementation and establishment of an adequate control architecture is an important next step. Existing activities within the Data Sharing Coalition, EU common data spaces, Gaia-X, International Data Spaces and other data-space frameworks should be further developed, as they are key enablers for this use case.

To strengthen participation, efforts should be made to increase customer knowledge about smart-grid applications through network-association information campaigns.

16.1.2 Virtual power plants

Virtual power plants (VPPs) are another technological enabler for accessing flexibility potential. In the context of this study, VPPs are a software-based solution for aggregating DERs by remote control. They can participate in spot or balancing markets and can balance internally.

16.1.2.1 Technical aspects

One key technical requirement is that DERs be linked using high-quality, secure communication systems with good network availability and low latency. Without this, short-term flexibility provisions are out of reach. Day-ahead scheduling might still be possible with lower-performing communication technologies, but short-term intraday operation will be difficult to fulfil.

Though the communication-technology requirements are high, the costs of the information and communications technology (ICT) must be as low as possible, especially in the case of small-scale DERs such as micro-CHPs and heat pumps; being able to integrate the DERs within the VPP as seamlessly as possible, in a plug-and-play manner, can help with this.

Besides the links between the DERs and a central VPP, additional communication channels are required to interact with data providers, DER operators, balancing responsible parties, balancing service providers, system operators and energy traders. It is crucial to implement standardised data and data-exchange processes between the involved parties – ideally over the entire EU power market.

With these best-case conditions in mind, three major gaps can be named:

High area coverage of communication networks. Not all European countries provide the low-cost communication networks – typically broadband or cellular – that are required for optimal VPP operation. Germany and France, for example, lack good coverage, which is an issue for the operation of distributed energy resources away from more populated regions. Communication technology expansion plans should take this into account.

Core DER standards. The link to DERs is currently categorised by the use of multiple interfaces. Some are proprietary protocols; others, like the German standard VHP ready, are national-level, while still others are international, such as the International Electrotechnical Commission's standard 61850, which defines communication protocols for intelligent electronic devices at electrical substations, and IEC 61158, which covers digital data communications for measurement and control of industrial computer network protocols. Increasing the adoption rate of core DER interface standards, preferably with an international scope, could drive down connection costs. Depending on the European member state, VPPs may also receive data through advanced metering infrastructure that can read DER-related data and standardise DER control features to reduce connection costs Internet of things (IoT) standards might also be used to increase system controllability through additional sensors and actuators.

Real-time-ready market communication. Market communication lacks the speed and scalability to cope with increased participation and the trend towards near real-time market processes. This could be solved with the sort of data-space-based market communication Gaia-X plans to begin testing in the German power market with its Energy Data-X project, which will probably begin in 2022.[255]

[255] Gaia-X, "The energy data space: the path to a European approach for energy," April 30, 2021, https://www.gaia-x.eu/sites/default/files/2021-06/Gaia-X_Data-Space-Energy_Position-Paper.pdf.

In addition to established, centralised VPP control mechanisms, multi-agent systems (MASs) may become more important. MASs connect autonomous entities that act individually while considering the common objective. Local decision-making improves privacy and reliability and requires less data communication than would a centralised control scheme. VPP and MAS interaction within a sub-pool or micro grid might be of interest in early stages of MAS development. The required stages of interaction are still open for discussion, since VPP control is decentralising and local systems are regaining more autonomy.

16.1.2.2 Current regulations

Like other flexibility use cases, VPP regulation should enable simple and fair participation in wholesale and balancing markets. VPP operation uses two types of aggregators: (1) integrated, which fulfils all required market roles – as energy supplier, producer and balancing responsible party, and (2) independent, which covers only specific roles within the flexibility provision. For example, a single balancing responsible party may handle DER flexibility at its own risk or may interact with another balancing responsible party for this task, or an independent aggregator could provide aggregation as a service, delivering the flexibility on request with no market-selling risks.

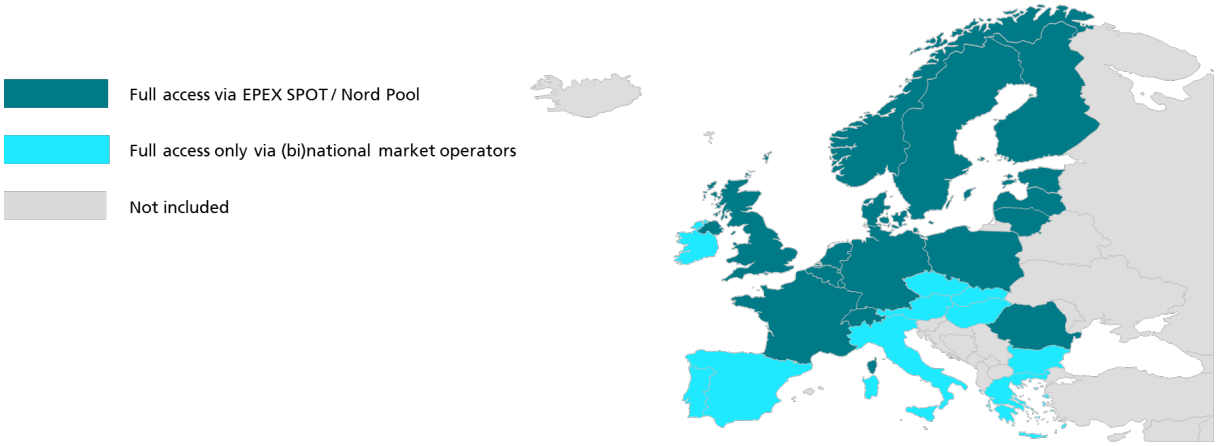
Integrated aggregators have benefited from covering all market roles and avoiding stakeholder interaction, the recent path – set by Regulation (EU) 2019/943 on the internal market for electricity and Directive (EU) 2019/944 on common rules for the internal market for electricity (IEMD) – liberalises the landscape[256]. The IEMD defines in Article 2(18) an aggregator as an enabler for producer aggregation (except for demand side flexibility): "a natural or legal person who combines multiple customer loads or generated electricity for sale, purchase or auction in any electricity market"[257]. Requiring EU member states to ensure fair energy market participation, or equal treatment by TSOs and DSOs, and transparent and clear market rules provides a base for independent aggregators. One key part is the simple access to short-term wholesale electricity markets in a European internal market. As Figure 95 shows, major parts of the European day-ahead and intraday markets can already be fully accessed by the two main market operators, EPEX SPOT and Nord Pool. The covered bidding zones of the two allow favourable bid sizes of 1 megawatt or less for smaller aggregators and, depending on the bidding zone and market product, provide beneficial lead times of 15 minutes or less and product lengths of 30 minutes or less. Under such conditions, all aggregated DERs, including those providing load flexibility, can gain an advantage. In this context the EU-wide requirement of a 15-minute imbalance settlement period by 2025, set out by the Electricity Balancing Guideline (EB GL)[258], will foster the development of short-term trading.

[256] The European Parliament and the Council of the European Union, "Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast)," *Official Journal of the European Union*, June 14, 2019, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32019R0943; the European Parliament and the Council of the European Union, "Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU (recast)," *Official Journal of the European Union*, June 14, 2019, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32019L0944

[257] European Commission, "Internal market in electricity from 2021," https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=LEGISSUM:4404055.

[258] The European Parliament and the Council of the European Union, "Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast);" and Selina Kerscher and Pablo Arboleya, "The key role of aggregators in the energy transition under the latest European regulatory framework," *International Journal of Electrical Power & Energy Systems* 134, January 2022, https://doi.org/10.1016/j.ijepes.2021.107361.

Figure 95. Access to European short-term wholesale electricity markets[259]



Regulation (EU) 2019/943 further strengthens the role of aggregators by enforcing the option of aggregation in balancing markets and by adding a non-discriminatory prequalification process for new balancing service providers.

Moreover, as part of the EB GL, the European Network of Transmission System Operators for Electricity (ENTSO-E) has started cross-border balancing markets that coordinate products in member and non-member states. The Trans European Replacement Reserves Exchange (TERRE) project, which developed a central replacement-reserve platform, has been operational since 2019[260]; the Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation (PICASSO) for automated frequency restoration (aFRR) began in 2021 in selected countries and the Manually Activated Reserves Initiative (MARI) for mFRR is expected to go live in 2022[261].

The ongoing development of the three platforms should simplify aggregators' market access to European countries, since the current market design, planned changes to the design, market price level and competitive landscape do not allow easy access to all aggregators, as shown in Figure 96.

[259] EPEX SPOT, *Trading at EPEX SPOT 2021*, 2021, https://www.epexspot.com/sites/default/files/2021-05/21-03-15_Trading%20Brochure.pdf; Nord Pool, "Rules and regulations," n.d., https://www.nordpoolgroup.com/trading/Rules-and-regulations/.

[260] ENTSO-E, Trans European Replacement Reserves Exchange (TERRE), n.d., https://www.entsoe.eu/network_codes/eb/terre/.

[261] ENTSO-E, Manually Activated Reserves Initiative (MARI), n.d., https://www.entsoe.eu/network_codes/eb/mari/.

Figure 96. Aggregator participation in European balancing markets[262]

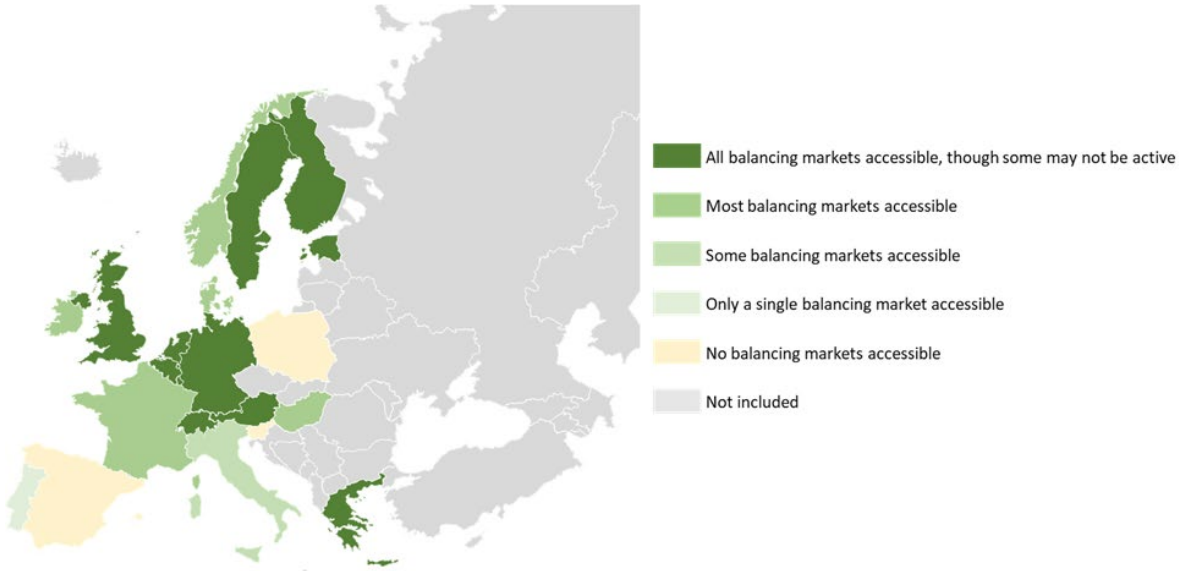


Figure 96 takes into account the following criteria to determine balancing-market accessibility[263]:

- The existence of a market mechanism rather than mandatory fulfilment;
- Product resolution of 1 megawatt or less of energy and/or capacity;
- Products to reach capacity in 30 minutes or less;
- Gate closure time (the time in which market participants must submit their final bids) in days;
- The possibility of all flexibility options (that is, not only generators and pump storages);
- The inclusion of non-symmetrical that products may facilitate the activation of DERs with more operation restrictions.

In replacement reserve, aFRR and mFRR markets, the merit-order activation sequence may allow flexibilities with restricted capacity to participate more easily (in comparison to the prorated approach used when all allocated assets need to provide flexibility).

From an operational point of view, Commission Regulation (EU) 2017/1485[264], usually known as the System Operation Guideline (SOGL), defines the general technical requirements of units participating in balancing markets. Detailed requirements are still defined by TSOs within the framework of legislative rules, so while TSO cooperation is preferred, it is not always required.

[262] ENTSO-E, "Survey on ancillary services, balancing market design 2020," May 2021, https://eepublicdownloads.azureedge.net/clean-documents/mc-documents/balancing_ancillary/2021/AS_Survey_2020_Results_Updated.pdf; ENTSO-E, *Balancing Report 2020*, 2021, https://eepublicdownloads.azureedge.net/clean-documents/Publications/Market%20Committee%20publications/ENTSO-E_Balancing_Report_2020.pdf; INESC TEC, *XFLEX HYDRO: D2.1 Flexibility, technologies and scenarios for hydro power*, September 2020, https://ec.europa.eu/research/participants/documents/downloadPublic?documentIds=080166e5d339b666&appId=PPGMS; smartEn, *The smartEn Map - European Balancing Markets Edition 2018*, 2018, https://smarten.eu/wp-content/uploads/2020/03/the_smarten_map_2018.pdf.

[263] smartEn, *The smartEn Map — European Balancing Markets Edition 2018*; Simone Minniti et al., "Local markets for flexibility trading: Key stages and enablers," *Energies* 11, no. 11, November 2018, https://doi.org/10.3390/en11113074; Kerscher and Arboleya, "The key role of aggregators in the energy transition under the latest European regulatory framework."

[264] European Commission, "Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation," *Official Journal of the European Union*, August 25, 2017, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32017R1485.

16.1.2.3 Future designs and factors driving participation

One obstacle to participation is that TSOs have different prequalification conditions. This creates an uneven playing field, especially within the new cross-border balancing markets being developed by the ENTSO-E projects PICASSO, MARI and TERRE. The differences in IT regulations can be significant, particularly in light of the high level of IT security required. Amending the SOGL, including ICT solutions that still allow smaller-scale DERs to participate by keeping system costs moderate, could overcome this challenge.

Simplifying the participation prequalification process, especially for the connecting network operator, could also increase participation by increasing automated market communication with technologies like advanced metering infrastructure to allow fast-tracking. This interaction could be implemented by the blockchain-based crowd-balancing platform Equigy, which allows handling of transactions, validation by TSOs and DSOs, and settlement based on data provided by the aggregators themselves or, preferably, by the original equipment manufacturers as a third party. However, a single unit cannot be activated by an aggregator in its market role as a balancing service provider[265].

To drive general consumer participation in VPP operation, a 2020 paper published by the 6th International Conference on Power and Renewable Energy identified the potential of gamification by analysing various consumer applications[266]. The study, motivated by the increasing number of prosumers with different kinds of flexible DERs, identified enablers, including a well-designed user interface, individual performance measurements and social engagement, which are attractive to more than 80% of users and can increase motivation to follow the guidance of an app. The results are also relevant for energy communities, which are discussed in the next section.

16.1.3 Energy sharing and peer-to-peer trading

Energy communities can be organised in up to two dozen ways. This section focuses on their energy-sharing aspects, as enforced by the EU Clean Energy Package[267].

16.1.3.1 Technical aspects

Information and communications technology systems provide energy communities with two core functionalities: monitoring capabilities, primarily for observing power flows among community members, and control over flexible DERs within the community to increase the consumption of energy generated. ICT systems also allow a community's energy surpluses and deficits to be traded on the wholesale markets by one or more energy suppliers.

Encouraging active participation in energy communities starts with recruiting new members. Once they are registered, members should receive help with technical setup; contracts and renewal processes should be defined, and exchange verification and monitoring processes clarified. Finally, in the settlement phase, the total amount of energy activated, and flexibility requested should be defined so that each successful transaction will be recognised and cleared for payment.

[265] Equigy, the Platform, accessed on October 12, 2021, https://equigy.com/the-platform/

[266] Behnaz Behi et al., "Consumer Engagement in Virtual Power Plants through Gamification," 2020 5th International Conference on Power and Renewable Energy (ICPRE), 2020, https://doi.org/10.1109/ICPRE51194.2020.9233110.

[267] European Commission, Directorate-General for Energy, *Clean Energy for All Europeans*, 2019, https://data.europa.eu/doi/10.2833/21366

TSOs and especially DSOs are an important part of this process, as they require member data to fulfil obligations like grid planning, active operation and settlement of charges. All relevant market communication should be as simple as possible to allow energy communities to scale up.

Energy communities are still in the adoption phase and are not fully recognised as participants in national markets, which may hinder the development of new energy communities.

Energy communities typically use centralised cloud infrastructure to monitor members' consumption and, if available, their DER assets through platforms like tiko Energy Solutions, GreenCom Networks and gridX. Usually a gateway, which communicates with the smart meter and the HEMS or BEMS system, is installed on the premises to gather data and dispatch any flexible DERs to maximise self-consumption of PV generation, and, if beneficial for the community, fulfil commands from the central platform. But there are obstacles:

Recent DER technology lacks single-interface controls behind the meter. This is solved by the new EEBus standard, which is expected be increasingly adopted[268].

The introduction of charges to control DERs via an OEM can be a showstopper if a third party, like an energy community, wants to interact with the DERs for flexibility purposes. This could be solved by allowing DER owners and appointed third parties free access for such usage.

The lack of standards for communicating with multiple energy traders participating in day-ahead and intra-day markets is another hindrance, because demand and generation must be aligned for each balancing group within an energy community[269].

An advanced metering infrastructure can simplify the operation of an energy community. It allows access to standardised data for monitoring, control and settlement, and may offer the option of delivering near-real-time price signals from other stakeholders, such as the DSO, to encourage energy-community members to support the power system[270].

In addition to centralised cloud-based community platforms, new technical approaches for distributed ledger technology, especially for peer-to-peer trading, are under discussion. P2P can be seen as an extension of energy sharing that is usually characterised by long-term, predefined fixed pricing mechanisms and continuously changing transaction conditions with full traceability between the participating peers, though most P2P approaches are still in the pilot stage. The Brooklyn Microgrid, active since 2016, was the first to use distributed ledger technology, in this case blockchain with smart contracts to handle energy transactions between the participating parties. Solutions are still being worked out to overcome distributed ledger technology challenges like scalability, privacy risks, high operational costs and security issues.

[268] EEBus Initiative, n.d., https://www.eebus.org/.

[269] A balancing group consists of consumers and generators within an energy community; the specific structure of balancing groups depends on multiple factors, including which supplier each member uses.

[270] Jenny Palm, *Energy communities in different national settings – barriers, enablers and best practices,* New Clean Energy Communities in a Changing European Energy System (NEWCOMERS) project, May 2021, https://www.newcomersh2020.eu/upload/files/Deliverable%203_3_%20Energy%20communities%20in%20different%20national%20settings_barriers%2C%20enablers%20and%20best%20practices.pdf; Pol Olivella-Rosell et al., "Design and Operational Characteristics of Local Energy and Flexibility Markets in the Distribution Grid," in *Design the electricity market(s) of the future,* European University Institute, 2017, https://data.europa.eu/doi/10.2870/420547

16.1.3.2 Current regulations

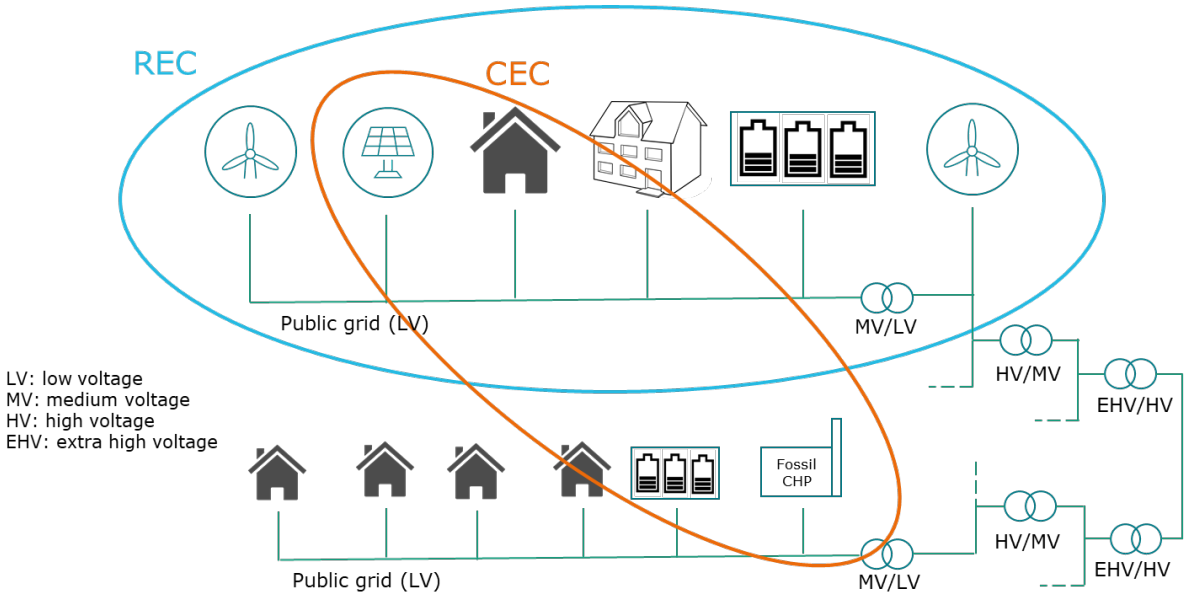
Regulation of energy communities should enable simple and fair access to the markets. Energy communities should be recognised and treated equally as market participants, and registration and licensing procedures should be transparent.

The baseline for the new role of energy communities is the Renewable Energy Directive (RED II), Article 2(16), concerning renewable energy communities (RECs), and IEMD, Article 2(11), concerning citizen energy communities (CEC)[271]. Both RECs and CECs allow energy sharing and supply within a community through engagement between producers, consumers and storers, and both exclude large enterprises from effective control.

- RECs can cover all energy sectors, including heating and cooling, and require shared energy of renewable generators in close proximity to the consumers.
- CECs cannot provide flexibility services to non-members or non-shareholders. They cover only the electricity sector and can be applied nationwide or across borders, depending on countries' regulations. Extension energy services to non-members or non-shareholders should be included in IEMD, Articles 2 and 16, and the provision of flexibility could be explicitly mentioned as part of the energy services. Adjusting the current RED II, Article 22, could alleviate a similar limitation.

Detailed requirements are defined at the member-state level, but a simplified graphical representation of the main differences in REC and CEC grids is shown in Figure 97.

Figure 97. RECs vs. CECs from a grid perspective[272]



[271] The European Parliament and the Council of the European Union, "Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU (recast)."

[272] Matteo Zulianello, Valerio Angelucci, and Diana Moneta, "Energy Community and Collective Self Consumption in Italy," 2020 55th International Universities Power Engineering Conference (UPEC), https://doi.org/10.1109/UPEC49904.2020.9209893; Republik Österreich Bundesministerium Klimashutz, Umwelt, Energie, Mobilität, Innovation and Technologie [Republic of Austria Federal Ministry for Climate, Action, Environment,, Energy, Mobility, Innovation and Technology], EAG Paket

From the viewpoint of member states, a major gap is the missing regulations for fostering the development of energy communities participating in energy sharing. In an analysis of 11 representative member states, eight show non-supportive market conditions:

Portugal. The decree-law 162/2019 allows renewable energy sharing within a "unit," which is typically an area in the same voltage level on the grid, with no spatial distance defined; each case is decided by a public authority, the Directorate General of Energy and Geology (DGEG). For power-flow monitoring in an REC or CEC, an advanced metering infrastructure must be used. As a result, smart metering devices must be installed by the local DSO, which is also responsible for settlement (on a 15-minute basis). A financial incentive for RECs is the elimination of higher-voltage grid charges for self-consumption within the community. Surpluses can be traded on the wholesale market over the counter, directly between two parties or on energy exchanges, and transactions are state-subsidised. Since early 2020, it has been possible to register RECs, but none are operational. Key issues include the complex processes of the connecting DSO, DGEG and other parties; lack of a smart-meter rollout; and the absence of support for defining the internal regulation system by, for example, creating templates or a single point of contact for help. Simpler self-consumption schemes are more attractive in terms of costs and risks. Finally, no CEC legislation yet in place[273].

Greece. As promising as the fast development of Greece's first energy-community-related regulation was, in 2018, more recent national regulation has favored large investments over strong community-based activities by giving the former a shorter priority period for licensing new generation[274].

Germany. Germany has a regulation model – the tenant electricity model – for collective self-consumption only. Instruments to support community energy sharing in a larger context and with less strict proximity requirements, in accordance with the EU directives concerning RECs and CECs, are still lacking[275].

Belgium. The development of energy communities in Belgium is hindered by multiple regional obstacles even though national REC/CEC implementations exist[276].

[Renewable Energy Sources Expansion Act (EAG)], *Bundesgesetzblatt 150 [Federal Law Gazette* 150*],* July 2021, https://www.ris.bka.gv.at/eli/bgbl/I/2021/150/20210727

[273] Dorian Frieden et al., "Are we on the right track? Collective self-consumption and energy communities in the European Union, *Sustainability* 13, no. 22, November 2021, https://doi.org/10.3390/su132212494; Campos Inês et al., "Regulatory challenges and opportunities for collective renewable energy prosumers in the EU, *Energy Policy* 138, March 2020, https://doi.org/10.1016/j.enpol.2019.111212; S. Hall et. al, "PROSumers for the Energy Union: mainstreaming active participation of citizens in the energy transition," Deliverable ND4.1, PROSumers for the European Union (PROSEU), 2019, https://cordis.europa.eu/project/id/764056

[274] Marula Tsagkari, "How Greece Undermined the Idea of Renewable Energy Communities: An Overview of the Relevant Legislation," *Law, Environment and Development Journal* 17, 2020, https://www.researchgate.net/publication/346096106_How_Greece_Undermined_the_Idea_of_Renewable_Energy_Communities_An_Overview_of_the_Relevant_Legislation/link/5fbb7397458515b797628f84/download.

[275] Dorian Frieden et al., *Collective self-consumption and energy communities: Trends and challenges in the transposition of the EU framework*, COMPILE, December 2020, https://doi.org/10.13140/RG.2.2.25685.04321.

[276] Wouter Vandorpe, David Haverbeke, and Laura Pellens, "Electricity regulation in Belgium: overview," Thomson Reuters Practical Law, March 1, 2021, https://ca.practicallaw.thomsonreuters.com/w-030-3627?transitionType=Default&contextData=(sc.Default)&firstPage=true; Dorian Frieden et al., *Collective self-consumption and energy communities: Trends and challenges in the transposition of the EU framework.*

Romania. National legislation considers only collective self-consumption to a maximum installed capacity of 100 kilowatts per consumer location, not RECs or CECs. In addition, local engagement in renewable projects in rural areas has been minimal[277].

Croatia. The newly introduced Croatian electricity market act of 2021 has shown major issues with regard to RECs and CECs[278]. CECs are limited spatially and allowed only if they use low-voltage transformers. RECs are restricted by voltage levels and their size is limited by the requirement that they use renewable generators of no more than 500 kilowatts. Both RECs and CECs are limited by a maximum production capacity of 80% of the capacity of all consumers in the community. Other challenges include low electricity prices, a lack of planned incentives for deployment and plans for restrictions on cooperative engagement.

*Cyprus***.** No national energy community legislation exists[279].

Czech Republic. Energy communities are currently hindered by "unresolved legislation, low consumer education and mistrust of renewable energy sources". Improved legislation is planned[280].

Regulations in three other member states are more supportive:

Italy. Law N8/2020 allows communities individual distributed generation less than or equal to 200 kilowatts within one interconnected low- or medium-voltage grid. In this area energy can be shared on an hourly basis. To lower investment risks, the community can receive grid-tariff refunds and a per-megawatt subsidy over 20 years for self-consumed electricity[281].

Netherlands. In the Netherlands renewable energy sharing is allowed within certain postal codes. For smaller projects, virtual net-metering and energy tax refunds are an option for financial reimbursement, while large projects can use feed-in tariffs to finance their investment. For energy cooperatives with non-renewable energy shares (comparable to a CEC), regulation supports origin tracking to gain a better market position.[282]

Austria. The Renewables Expansion Law of 2021 introduced clear definitions of grid segments and DSO concession areas for RECs and CECs and allowed energy sharing and aggregation. Among the benefits for RECs are reduced grid charges and a market premium for up to 50% of locally produced surplus energy. However, the rules for energy sharing are legally fixed and applied by the DSO.[283]

In addition to laws and regulations, cost-reflective charges, which take into account the imposed costs of grid usage while rewarding the user for grid-friendly behaviour, can encourage active

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[277] Sorin Cebotari, "Against all odds: Community-owned renewable energy projects in north-west Romania," ACME: An International Journal for Critical Geographies 18, no. 2, May 2019, https://acme-journal.org/index.php/acme/article/view/1556; Dorian Frieden et al., Collective self-consumption and energy communities: Trends and challenges in the transposition of the EU framework.

[278] Dorian Frieden et al., "Are we on the right track? Collective self-consumption and energy communities in the European Union."

[279] Jenny Palm, *Energy communities in different national settings – barriers, enablers and best practices*

[280] Jan Pojar & Jakub Kvasnica, 2021. "Upscaling energy efficiency via energy communities," Proceedings of Business and Management Conferences 12713417, International Institute of Social and Economic Sciences.

[281] Dorian Frieden et al., *Collective self-consumption and energy communities: Trends and challenges in the transposition of the EU framework*.

[282] Campos Inês et al., "Regulatory challenges and opportunities for collective renewable energy prosumers in the EU

[283] Stephan Cejka, Dorian Frieden, and Kaleb Kitzmüller, "Implementation of self-consumption and energy communities in Austria's and EU member states' national law: A perspective on system integration and grid tariffs," CIRED 2021 Conference, September 2021, https://www.360ee.at/wp-content/uploads/2021/03/CIRED-2021-Paper-Implementation-of-self-consumption-and-energy-communities-in-Austria_s-and-EU-mem-2.pdf; Dorian Frieden et al., *Collective self-consumption and energy communities: Trends and challenges in the transposition of the EU framework*.

consumer participation. Current mechanisms that might include reduced grid charges can be challenging at scale when too many grid users are favored by lower costs and those who don't belong to the energy community are burdened with high system costs. This topic should be analysed further and addressed accordingly.

All in all, energy communities are still a new concept, and activities around them should be closely monitored and lessons shared among member states and beyond.

16.1.3.3 Future designs and factors driving participation

A 2021 analysis of energy community projects in Europe published in *Renewable and Sustainable Energy Reviews* shows the necessity of clear regulatory frameworks, financing and public incentives to improve conditions for energy communities; the current uptake of energy communities focuses on self-consumption without further activities like demand side flexibility or market aggregation. Another article, published as part of the EU's Newcomers project[284], identified multiple enablers – including a decentralised power system, availability of renewable energy options with low costs compared with centralised generation, advanced metering infrastructure or regulation to allow shared energy in an apartment complex and microgrid deployments – and major barriers, including centralised power systems, few incentives for DSOs to connect to smaller-scale DERs, high DER connection costs and individual photovoltaic ownership.

Teaching citizens about the possibilities of energy communities could foster participation. For example, an online survey in Germany showed a "rather positive attitude towards RECs" among those who knew about them, but also found that 40% of survey participants were unaware of the concept[285]. RECs were generally perceived as a costly and resource-intensive instrument for citizen engagement, particularly for lower-income households. Lack of time for active engagement, limited financial resources, lack of knowledge and skills, and red tape were cited as hurdles. Still, the Newcomers project makes the point that an established active prosumer culture can serve as an enabler for energy communities.

16.1.4 District heating and cooling

16.1.4.1 Technical aspects

To draw on the flexibility services of electrified district heating and cooling (DHC), technical preconditions should be fulfilled by integrating electric district heating in TSO and DSO stability services and deploying cybersecure remote-control systems. Increasing the use of information and communications technologies and the flow of data for digital flexibility create further opportunities, but also increase the risk of cyberattacks. Safe and trustworthy data frameworks ensuring customers' data security and the stability of TSOs and DSOs are needed.

Electric district cooling requires the construction of large networks and equipment to provide cooling and hot water, which entails higher infrastructure investment than decentralised electric

[284] Jenny Palm, *Energy communities in different national settings – barriers, enablers and best practices.*

[285] Anna Kracher, "Renewable Energy Communities - Exploring behavioral and motivational factors behind the willingness to participate in Renewable Energy Communities in Germany," the Industrial Institute for Industrial Environmental Economics (IIIEE), Lund University, May 2021, https://lup.lub.lu.se/student-papers/record/9058633.

cooling[286]. Hybrid systems could reduce costs. Pilot projects could help improve district cooling concepts and make them competitive with decentralised electric cooling.[287]

16.1.4.2 Current regulations

Providing digital flexibility services to the electricity system requires a clear regulatory framework for DHC at the EU level, covering pricing, metering, efficiency requirements, connecting, planning, policy support, data protection and the use of consumer data for the provision of flexibility by operators. Currently, DHC issues are addressed in various regulations, including the RED II[288], the Energy Efficiency Directive (EED)[289], the Energy Performance of Buildings Directive (EPBD)[290], IEMD[291] and guidelines on state aid[292]. But there is no comprehensive regulatory document, which, among other things, opens the possibility of gamification, as DHC operators are typically monopolies. Further, because the definition of an efficient DHC does not include the provision of flexibility, when DHCs are assessed, flexibility will not be considered. Finally, electricity for heating is costly compared with fossil fuels, as taxes and fees increase energy costs.

A clear definition of DHC systems as energy communities and participants in the electricity market through flexibility services is needed. Article 22 of the RED II focuses on *renewable* energy communities. Article 2 of IEMD defines "citizen energy communities" as entities that "engage in [and] provide other energy services ... to members or shareholders," excluding energy communities that provide services to non-members. Article 16 guarantees energy-community access to all electricity markets and treats the communities as final consumers and market participants engaged in aggregation. Non-renewable DHC communities providing flexibility are excluded from the definitions, the provision of flexibility services is not explicitly mentioned, and energy services are limited to members or shareholders.

16.1.4.3 Future designs and factors driving participation

No comprehensive regulatory document currently exists to enable electric DHCs, particularly DHCs as energy communities, to participate in the market and provide digital flexibility services. Until comprehensive regulations are created, the following adjustments are recommended:

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[286] Jenny Palm and Sara Gustafsson, "Barriers to and enablers of district cooling expansion in Sweden," *Journal of Cleaner Production* 172, January 2018, https://doi.org/10.1016/j.jclepro.2017.10.141

[287] Satu Paiho and Heidi Saastamoinen, "How to develop district heating in Finland?," *Energy Policy* 122, November 2018, https://doi.org/10.1016/j.enpol.2018.08.025.

[288] The European Parliament and the Council of the European Union, "Directive (EU) 2018/2001 of 11 December 2018 on the promotion of the use of energy from renewable sources (recast)," *Official Journal of the European Union*, December 21, 2018, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2018.328.01.0082.01.ENG

[289] The European Parliament and the Council of the European Union, "Directive (EU) 2018/2002 of 11 December 2018 amending Directive 2012/27/EU on energy efficiency," *Official Journal of the European Union*, December 21, 2018, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv%3AOJ.L_.2018.328.01.0210.01.ENG

[290] The European Parliament and the Council of the European Union, "Directive (EU) 2018/844 the European Parliament and of the Council of 30 May 2018 amending Directive 2010/31/EU on the energy performance of buildings and Directive 2012/27/EU on energy efficiency," *Official Journal of the European Union*, June 19, 2018, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32018L0844

[291] The European Parliament and the Council of the European Union, "Directive (EU) 2018/844 the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU (recast)," *Official Journal of the European Union*, June 14, 2019, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32019L0944

[292] European Commission, "Guidelines on State aid for environmental protection and energy 2014-2020 (2014/C 200/01)," 2021, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52014XC0628(01)

- provide a definitive and transparent framework for DHC, regulating market access (electricity, shifting of loads and heat), connection issues of suppliers and consumers, and use and misuse of market power and customer data;
- include a provision of flexibility in defining efficient DHC in the EED;
- address integration of DHC into the electric network in IEMD next to Article 33;
- include DHC as a potential energy community and flexibility provider not only for its members and shareholders but beyond, in IEMD, articles 2 and 16;
- equate electric DHC providing flexibility services with DHC using renewable energy and define both as energy communities in RED, Article 22;
- reduce the taxes and fees on electricity for heating to less than those on fuels;
- create secure and trustworthy data spaces that allow safe and sovereign data exchange between grid operators and heat and flexibility providers;
- consider DHC infrastructure and appliances when setting up identity and trust mechanisms and processes; and
- allow trusted third-party access to DHC data to improve planning and the integration of flexibility into all markets.

Planning certainty can encourage investment in DHC. This security could be provided by government guarantees for combined heat and power and efficient large-scale heat pumps providing flexibility services. However, other barriers should be addressed first, such as gaps awareness; lack of skilled systems engineers and employees; lack of confidence among municipal planners in the technology's ability to meet heating needs; local geographic, path-dependency or cultural factors. Changing attitudes towards climate-friendly energy production and consumption in combination with information campaigns by trustworthy organisations, along with rising energy prices, could push municipal planners towards DHC, particularly more efficient DHC.

16.1.5 Building energy management systems

16.1.5.1 Technical aspects

Integrating building flexibility into energy markets is feasible only when control and communications technology is secure and low-cost. Standardised protocols for building-operation technologies and their interoperability with control boxes and metering devices are key. Furthermore, easy integration in the communication systems of grid operators allows for standardised participation in grid services. To achieve this, EU-wide protocols for flexibility by building technologies, especially electric heating and cooling appliances, and a common definition of technical requirements for flexible building technologies are necessary.

16.1.5.2 Current regulations

Requirements for providing flexibility from commercial buildings to the power system are addressed in the EPBD's Smart Readiness Indicator (SRI)[293], which was adopted by the European Commission in 2020 to "assess a building's ability to adapt to advanced technologies in terms of

[293] European Commission, "Commission Implementing Regulation (EU) of 14.10.2020 detailing the technical modalities for the effective implementation of an optional common Union scheme for rating the smart readiness of buildings," October 14, 2020, https://ec.europa.eu/energy/sites/ener/files/smart_readiness_buildings_implementing_act_c2020_6929.pdf

its performance capacity and energy flexibility"[294]. Use of the SRI and buildings' contributions to energy flexibility remain low across Europe. Rules and regulations are not defined consistently but should be to encourage broader participation of building appliances, particularly electric heating and cooling technologies. EU legislation does offer general recommendations and establishes requirements for variable tariffs[295], but implementation, availability and adoption of those tariffs and other incentives for the building provision are lacking in many member states. Also, grid operators often lack instruments and incentives for low- and medium-voltage flexibility or are prohibited from using flexibility for grid operation. So far, no market framework under which buildings can provide flexibility to grid operators has been established.

16.1.5.3 Future designs and factors driving participation

Use of small-scale PV systems, the electrification of buildings and electric mobility will increase, in part because RED II includes regulations for minimum renewable deployment in commercial buildings. As a result, many small-scale assets will be available to provide flexibility to the power system or to be used in another system-friendly way. The following measures could enable flexibility business cases in buildings:

- smart metering infrastructure;
- safe and trustworthy data frameworks;
- secure authorisation of TSO/DSO triggers and compatibility with BEMS control systems; and
- pilot projects to test and showcase solutions.

It's especially important to develop a market design that allows flexibility providers to participate in grid management and other electricity markets through variable-grid rates, time-of-use rates, locational prices, collective prequalification (in which one prequalified device serves as a sample for other, similar devices) of building appliances for grid services, and implementation of secure and trustworthy data spaces.

Participation can be improved by increasing knowledge of operation and benefits, by increasing trust in the data-sharing infrastructure and through robust cybersecurity measures.

16.1.6 Industrial hybrid heating

16.1.6.1 Technical aspects

The main technical requirement for the provision of industrial flexibility is the integration of TSO/DSO triggers into the power market. For this, energy managers must be able to integrate external market and grid signals into their operations using new analytical capabilities like price-spread forecasting. Fears that providing load flexibility will have negative impacts on production processes and cause delays are hindering stronger diffusion, and the lack of a common EU strategy on reliable IoT communications for the energy system can lead to significant additional efforts for operators and hamper effective cybersecurity measures. Improving load and generation forecasts on the distribution level, and reliable and secure communications between flexibility providers and grid operators, are seen as key enablers for industrial load flexibility.

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[294] European Commission, "'Smart' buildings — smart readiness indicator (arrangements for rollout of scheme)," July 16, 2020, https://ec.europa.eu/info/law/better-regulation/have-your-say/initiatives/12365-%E2%80%98Smart%E2%80%99-buildings-smart-readiness-indicator-arrangements-for-rollout-of-scheme-_en.

[295] The European Parliament and the Council of the European Union, "Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU (recast)," *Official Journal of the European Union*, June 14, 2019, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32019L0944.

16.1.6.2 Current regulations

Participation in industrial flexibility, together with demand-side resources (DSR), is provided for in Article 17 of IEMD. Member states could encourage participation in DSR in the following ways:

- technical requirements for TSO/DSO participation should promote access for DSR, specifically for grid tariffs in Article 15.4 and market participation in Article 15.8 of the EED;
- aggregation in all markets should be pursued and should allow the participation of aggregators;
- technical requirements should be adjusted in line with consumer capabilities and market requirements.

From a regulatory viewpoint, all EU markets should be open for industrial demand side flexibility, though current regulations do not contain specific incentives or measures for integrating industrial flexibility into the power system.

16.1.6.3 Future designs and factors driving participation

Industrial flexibility is a key part of various pieces of EU legislation, but because its use is still low in many EU member states the accessibility of wholesale, retail, ancillary and balancing markets should be monitored. Also, prequalification requirements and methods for communicating and billing should be evaluated for suitability, fairness and transparency. Some industrial flexibilities also need a transparent and fair definition for a baseline demand profile.

Aggregated prequalification could reduce administrative and measurement burdens. Technical requirements can be adjusted according to industrial flexibility capabilities such as the availability of capacity, required size of bid and frequency of auctions (the more the better, considering seasonal deviations of DSR resources and the option of asymmetric bidding). Clear and transparent incentives for flexibility provision could provide investment security.

More industrial flexibility providers would participate if concepts and experiences were shared with the industry. Lack of technical know-how and information on regulatory and administrative processes is a barrier for small and medium entities whose core business is not energy purchase. Regulations and processes must become more user-friendly.

16.1.7 Home energy management systems and residential heat pumps

This section describes the technical, regulatory and uptake drivers for both the HEMS and residential heat pumps business cases due to their significant synergy in future residential energy systems.

16.1.7.1 Technical aspects

Recent technological advancements have created interesting opportunities for integrating residential buildings into the emerging flexibility market, but the full potential of HEMS flexibility cannot be monetised without defining common network and communications standards for HEMS components.

For instance, because a number of technology frameworks and protocols are available to connect storage systems and heat pumps to HEMS, manufacturers use different communication protocols to connect to the grid, which presents challenges in terms of interoperability and user portability. Open standards and application programming interfaces for connectivity and communication are immediate requirements for the early-stage flexibility market. Also, heat pumps and batteries should comply with the existing local building's energy and construction codes to improve the

flexibility calculation. In the case of heat pumps, flexibility requires frequent on/off cycles, which could impact the performance and lifetime of the pump's compressors. Manufacturers could address this issue by providing a flexibility operating mode for heat pumps.

16.1.7.2 Current regulations

Flexibility in EU building stock is primarily discussed in the Smart Readiness Indicator, which covers "features for increased energy savings, benchmarking and flexibility, and enhanced functionalities and capabilities provided by more interconnected and intelligent devices."[296] Energy flexibility, including the building's ability to participate in demand response, is one of the key criteria set by the SRI. Integrated battery storage (covered in the SRI's impact criteria) and heat pumps (covered in the smart-ready services catalog in the regulation's Annex VI[297]) are the main flexible components of HEMS. Increasing on-site renewable-energy generation and self-consumption are also driving flexibility in residential buildings, and the link between renewables, self-consumption and flexibility is highlighted in the proposed renewable energy directive[298].

Despite regulations, however, flexibility from home batteries and heat pumps is not well implemented in Europe, and flexibility-market participation mechanisms are not well known to residential consumers. Transparent grid access, remuneration for small-scale flexibility and interoperability of HEMS systems are major roadblocks that must be addressed soon to achieve the full flexibility potential of residential buildings.

16.1.7.3 Future designs and factors driving participation

Favourable self-consumption policies are also encouraging consumers to shift towards distributed renewables generation, and the proliferation of home batteries and heat pumps in European dwellings is projected to increase significantly over the next few years. This implies a huge opportunity for energy-system flexibility, but it's highly dependent on technical enablers, customer behaviour and market design.

The technical enablers required include:

- smart meters with mandatory interfaces for home area networks and connecting protocols;
- energy flexibility characterisation and labeling for smart appliances and homes;
- remote control and monitoring of heat pumps and batteries to perform automated demand response using grid signals;
- interoperable and intelligent smart home gateways, along with open-source automation software, to facilitate service portability;
- an open but regulated data platform that would allow flexibility service providers to improve their final value proposition and meet the demands of end consumers.

[296] European Commission, "Commission delegated Regulation (EU) 2020/2155 of 14 October 2020 supplementing Directive (EU) 2010/31/EU of the European Parliament and of the Council by establishing an optional common European Union scheme for rating the smart readiness of buildings, *Official Journal of the European Union*, December 21, 2020, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32020R2155.

[297] European Commission, "Commission delegated Regulation (EU) 2020/2155 of 14 October 2020 supplementing Directive (EU) 2010/31/EU of the European Parliament and of the Council by establishing an optional common European Union scheme for rating the smart readiness of buildings, https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32020R2155&from=DA.

[298] European Commission, "Proposal for a Directive of the European Parliament and of the Council on the promotion of the use of energy from renewable sources (recast)," February 23, 2017, https://eur-lex.europa.eu/resource.html?uri=cellar:3eb9ae57-faa6-11e6-8a35-01aa75ed71a1.0007.02/DOC_1&format=PDF.

Market design should encompass fair and non-discriminatory smart-grid access for residential flexibility, including lower tariffs for sharing electricity with the grid.

The benefits of participating in the flexibility market should be clearly communicated to residential consumers. Energy efficiency and cost-saving drive the purchase of smart appliances and storage, and the benefits of flexibility should be integrated at the initial stage of smart-home investment. Finally, member states must minimise the administrative burden for trading a lower volume of flexibility for smart-home owners.

As for behavioral aspects, customer engagement in heat pumps and storage flexibility is a major challenge. Winning customers' trust enough that they will hand over data and remote control of home appliances requires new regulations or certification of third-party service providers. Consumers also need assistance overcoming technical barriers to operating and maintaining the flexibility services in a complex digital environment.

16.1.8 Smart charging and vehicle to grid

16.1.8.1 Technical aspects

From a technical point of view, a direct prerequisite of smart charging is an intelligent charging infrastructure that can reduce or shift the charging process of electric vehicles. Bidirectional charging requires vehicle-to-grid-ready chargers, which are expensive, as the technology is mostly used in pilot projects and still not widely available. Finally, the activation of electric vehicles as a flexibility resource requires monitoring, communication and, to some extent, control of energy flows. The energy taken from the grid and fed back into it needs to be identified through smart metering, using either stand-alone devices or devices embedded in charging points in compliance with national restrictions. This hardware restriction is complemented on the software side with the necessity for a billing architecture that enables the tracing of cost and revenue streams from various EV business cases using multiple interfaces, as most business cases involve many parties, including charge-point operators, e-mobility service providers that handle communication and billing, and DSOs.

Protocols already exist for smart charging interfaces. They include the Open Charge Point Protocol 1.6, for communication from the charge point to the charge-point operator, and the International Electrotechnical Commission's ISO 15118-2, which enables communication between an EV and the charging point[299]. But for bidirectional charging, standards to replace proprietary systems – such as ISO 15118-20, the latest version of the 15118 series – are still under development[300]. Because data must be shared, cybersecurity must be robust. Independent of hardware and software requirements, both smart charging and V2G are subject to sociotechnical barriers; EV users might be unaware of the possibility of using smart charging, but the profitability of EVs depends on the driving patterns and acceptance levels of their users. If EVs are not connected to the grid, at times when prices for charging and discharging are attractive, savings, revenue and the system impact will be low.

Also, users may avoid smart charging and V2G because they fear battery degradation and a loss of control if the charging process is controlled algorithmically or by a third party, especially for V2G,

[299] Nationale Plattform Elektromobilität, "Roadmap zur Implementierung der ISO 15118 [Roadmap to the implementation of ISO 15118]" (2020), https://www.google.de/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&ved=2ahUKEwj8-Zac2Z30AhVkh_0HHaoWBEUQFnoECAUQAQ&url=https%3A%2F%2Fwww.plattform-zukunft-mobilitaet.de%2Fwp-content%2Fuploads%2F2020%2F12%2FNPM_AG5_AG6_2020_Q4_ISO15518.pdf&usg=AOvVaw2VQ5M09XpLaIw94twKg2mM.

[300] International Organization for Standardization (ISO), "ISO/FDIS 15118-20," https://www.iso.org/standard/77845.html.

or if they are not ready to accept a certain loss of comfort and expect their vehicle to be fully charged as quickly as possible.

16.1.8.2 14.1.8.2 Current regulations

EVs and the corresponding charging infrastructure are defined in the Deployment of Alternative Fuels Infrastructure Directive[301], but the directive does not explicitly outline smart charging or vehicle to grid and its electricity system integration.

Directly or indirectly, EVs are addressed in multiple directives, including the EPBD, RED II and the proposal for its amendment, and IEMD. Once EV users applying smart charging or V2G are categorised as "renewables self-consumers," by RED II, Article 2.14, or "active customers," by articles 2(8) and 16 of the IMED, they are explicitly entitled to non-discrimination, cost-reflective network charges and, like all customers, to request a dynamic contract with at least one supplier. The non-discrimination clause means self-consumers must not be subjected to charges or fees for self-consumed electricity or to double charging (RED II, Article 21). Overall, EV users should receive incentives for smart charging, but they have no obligation to adapt their charging pattern in a system-friendly manner.

Concerning EV charging infrastructure, owners of new or renovated "non-residential" buildings with more than 10 parking spaces inside or adjacent to the building are obligated to provide at least one charging point. They also must lay conduits to enable later installation for more in one in every five parking spaces inside or adjacent to the building (EPBD Article 8(2)). Owners of new or newly renovated residential buildings with more than 10 spots have to provide conduits for every parking space (EPBD Article 8(5)). Independent of the building type or size, the EPBD does not explicitly outline obligations and supports for smart-charging infrastructure but does require member states to provide measures for simplifying the deployment of charging infrastructure and addressing regulatory barriers such as permitting and approval (EPBD Article 8(7)).

16.1.8.3 Future designs and factors driving participation

Information on battery charging and battery degradation is a key requirement of the diffusion of smart charging, and both should be promoted in the future. Another prerequisite is that financial incentives for smart charging and time-of-use systems in general be sufficiently profitable to compensate for a potential loss of comfort. These incentives can be driven by the market or by fiscal charges, such as exemptions for self-consumption and reduced charges for grid-friendly behavior.

While smart charging is already categorised in EU regulations, the role and status of V2G as a form of participation in energy markets should be clarified, with a prohibition against discrimination regarding generation assets. Grid charges and taxation for grid feed-in must also be established, and EV should be defined as a generator to avoid double-charging.

16.2 Analysis of key EU documents

This section provides a brief summary of key EU documents with regard to flexibility provision, which may be from large-scale applications, such as virtual power plants and industrial demand response, or from consumers who have EVs or home energy storage systems.

[301] The European Parliament and the Council of the European Union, "Directive 2014/94/EU of the European Parliament and of the Council of 22 October 2014 on the deployment of alternative fuels infrastructure," *Official Journal of the European Union,* October 28, 2014, https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32014L0094&from=en

16.2.1 The IEMD

IEMD accounts for two types of flexibility resources: demand response and aggregation of consumers, including EV users and HEMS owners.

16.2.1.1 Demand response and aggregation of "final customers" (IEMD Article 17)

Participation of demand response in electricity and ancillary services markets is explicitly supported for final customers, individually and through aggregation, as discussed in IMED Article 17, which considers final customers to be end users or EV owners, as opposed to intermediate customers, who may buy and then resell products or services. The IEMD ensures that technical requirements for demand response in all markets are established based on market characteristics and capabilities of the demand response system. Demand response participants are obligated to compensate other participants or balancing responsible parties if they are affected by the demand-response activation. This compensation shall not be a barrier to demand response. Overall, the technical requirements for participation in all markets should be based on market requirements, not on historical values that may have been designed for conventional generators. No technical approach for the compensation of demand response measures is currently specified, but individual compensation can cause high transaction costs, which would be reduced by standardisation.

16.2.1.2 Final customers, EV users, HEMS owners, self-consumers

Non-discrimination is supported, but explicit support for flexible customers is contained in several provisions.

- According to Article 11, the national regulatory framework should enable suppliers to offer dynamic price contracts, which are a low-level enabler for the participation of small-scale flexibility resources. Customers can request a dynamic contract with at least one supplier and with every supplier that has more than 200,000 customers.
- Article 8 defines electric vehicle owners, HEMS owners and self-consumers as active or final customers or as "a group of jointly acting final customers" who consume or store electricity generated within their premises or who sell self-generated electricity or participate in flexibility or energy efficiency schemes. As such, they must not be discriminated against and are entitled to cost-reflective network charges.
- According to Article 15.4, active customers are explicitly not privileged in terms of their contribution to overall sharing and are responsible for the imbalances they cause. Article 15.4 also prohibits net metering. Article 15.2 holds active customers responsible for imbalances they cause.
- Article 20 requires that smart-metering systems support market participants' optimisation of electricity use but specifies that smart-metering systems be paid for by the consumers if the associated cost is not overcompensated by the systemic benefit. It also states that smart-metering systems must allow access to historic and near-real-time consumption and feed-in to the grid in order to support demand response and other services and that member states ensure the interoperability and remote access of smart-metering systems.
- According to Article 21, where the cost-benefit assessment of smart-metering systems is negative, member states need to ensure that customers can still obtain a smart meter on request at their own expense.

16.2.2 RED II

The 2018 recast of the 2001 Renewable Energy Directive is particularly relevant for small-scale consumers who generate electricity and for renewable energy communities. It complements the IMED definition of active consumers and citizen energy communities.

RED II defines a renewables self-consumer as "a final customer operating within its premises … who generates renewable electricity for its own consumption, and who may store or sell self-generated renewable electricity."

According to Article 2.14, renewables self-consumers must not be subject to charges or fees for self-consumed electricity. In addition, Article 21.2 ensures that there will be no double charges for storage systems for self-consumed electricity. If the produced energy surpasses the self-consumer's demand, the consumer's rights and obligations as a final customer include the right to receive remuneration for feed-in electricity (Article 21.2c). Deriving from this, renewables self-consumers have no obligation to conceptualise self-consumption in a system-friendly manner.

Article 21 requires member states to adopt an enabling framework for renewables self-consumers. This framework shall address issues of accessibility to renewables self-consumption by all final customers, including those in low-income or vulnerable households. It shall provide incentives to building owners to create opportunities for renewables self-consumption and grant renewables self-consumers access to existing support schemes and to all electricity markets. It requires that self-consumers contribute to the overall cost-sharing of the system when electricity is fed into the grid.

RED II also covers renewable energy communities, which are legal entities based on open and voluntary participation that is controlled by members or shareholders, who are located within close proximity of the renewable energy projects.

Shareholders are defined as natural persons, small or medium-sized enterprises or local authorities.

In contrast to energy utility companies, the primary purpose of RECs is to provide environmental, economic or social benefits rather than financial gain (Article 2.16). According to Article 22.2, RECs are entitled to produce, consume, store and sell renewable energy; share renewable energy produced within the community; and access all suitable energy markets directly or through aggregation.

Like renewables self-consumers, RECs are entitled to an enabling framework ensuring:

- that unjustified regulatory and administrative barriers be removed;
- that the relevant DSO cooperate to facilitate energy transfer within the community;
- that all consumers, including those in low-income and vulnerable households, be able to participate;
- that access to financing is facilitated by the availability of information and the provision of tools; and
- that public authorities enabling, setting up and directly participating in RECs be supported.

According to Article 22.7, member states must consider the specific characteristics of RECs in the design of support schemes for renewables and must ensure that they can compete for support on a level playing field.

16.2.3 Regulation (EU) 2019/943 on the internal market for electricity

Regulation (EU)2019/943, on the internal market for electricity, does not specify individual technological rules. Instead, it ensures that all markets theoretically be open for various demand-

side flexibility resources. It does not necessarily incentivise the activation and market integration of these resources. It promotes the following flexibility provisions:

- Day-ahead and intraday markets (Article 8) must allow trading as close to real time as possible, and in time intervals at least as short as the imbalance settlement period. They must provide products with bid sizes of 500 kilowatts or less to allow for the effective participation of demand side response, energy storage and small-scale renewables, including direct participation by customers.
- Balancing markets (Article 6) must ensure effective non-discrimination between market participants and take into account the technical needs of the electricity system and the technical capabilities of generation sources, energy storage and demand response.
- Redispatching (Article 13) should be open to all generation technologies, all energy storage and demand-response technologies. Resources to be redispatched should be selected among generating facilities, energy storage or demand response using market-based mechanisms.
- Network charges (Article 18) cannot discriminate (positively or negatively) in energy storage or aggregation and cannot disincentivise self-generation, self-consumption or participation in demand response.

16.2.4 The EED

Directive 2018/2002[302], on energy efficiency, is particularly relevant for industrial demand response, and complements the demand response regulation in the IEMD:

- All electricity markets should be open for demand response.
- Network tariffs should incentivise demand response, whereas detrimental tariffs should be removed.
- The participation of demand-side resources should be encouraged.
- Technical modalities by TSOs and DSOs should promote access for demand-side resources and should be adjusted in line with consumer capabilities and market requirements.

16.2.5 The European Green Deal, Fit for 55 and proposal to amend RED II

With the European Green Deal, the EU has underlined the need to involve and benefit consumers and integrate renewables, energy efficiency and other sustainable solutions. It supports the deployment of innovative technologies that enable sector integration (Article 2.1.2). The Fit for 55 legislative package, presented in July 2021, is a framework that outlines how the EU can reduce its greenhouse gas emissions substantially and become climate neutral by 2050. The package includes a revision of the RED II, the EED and the EPBD, which all aim to increase energy savings and the share of renewables. Fit for 55 recognises the necessity of integrating renewables into the system, though its provision for flexibility – both directly, from renewables, and through the demand side – is less pronounced.

The proposal for an amended RED II emphasises the importance of facilitating system integration for renewable electricity. It recognises that aggregators, consumers, storage systems and EVs can all play a role in reaching this goal.

The following aspects are addressed:

[302] The European Parliament and the Council of the European Union, "Directive (EU) 2018/2002 of the European Parliament and of the Council of 11 December 2018 amending Director 2012/27/EU, on energy efficiency," *Official Journal of the European Union*, December 12, 2018, https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32018L2002&from=EN.

TSOs and DSOs are encouraged to make real-time information on the energy mix digitally accessible for market participants, including aggregators, consumers, EV charging points and smart-metering systems. This could facilitate the availability of real-time prices.

Real-time EV data is necessary for functioning smart-charging concepts, and in the proposal to amend RED II, manufacturers of batteries and EVs are required to make it available. This covers location and battery capacity, state of health and state of charge. Data availability is supposed to be granted both to EV users and third parties in a non-discriminatory way and at no cost. How the access to data and control of vehicles is granted, however, is not specified.

Member states must ensure that power recharging points that are not publicly accessible support smart charging and, where appropriate, bidirectional charging, fulfilling the requirements for functioning smart charging infrastructure. Details regarding the deployment of bidirectional charging infrastructure are not further specified.

Finally, member states are encouraged to ensure that the national regulatory framework does not discriminate against participation in electricity markets on the basis of congestion, provision of flexibility or balancing services for small-scale flexibility resources.

16.3 Analysis of data-sharing frameworks

The communication "Powering a Climate-Neutral Economy: An EU Strategy for Energy System Integration" indicates the key role that digitalisation and data spaces, or frameworks, could play in the future[303]. It discusses a common European energy data space and focuses on energy use cases in the EU's data strategy. The provision of data is driven by the smart meter rollout, which should allow demand response not only from large-scale industrial applications but also from small-scale flexibilities. It is expected that close to 225 million smart meters for electricity and 51 million for gas will be installed in the EU by 2024, replacing 77% of existing electricity meters and 44% of gas meters[304]. Several instruments should support the financing and setup of data spaces and digital infrastructures, including Connection Europe Facilities, InvestEU, Digital Europe Program and structural funds supported by the Horizon Europe programme. The extension of communication grids (including 450 megahertz mobile networks) is addressed by the EU digital strategy and Connection Europe Facility Digital, the digital arm of the Connecting Europe Facilities programme. These strategies and programmes address the faster diffusion and availability of communication technologies and should support and enable communication links to all RES generation and improve black-start capability.

The aim of the communication "A European Strategy for Data" is the creation of a data-agile economy, especially for start-ups and small and medium-sized enterprises[305]. A European data space should create a single, open-scheme data market across the public and private sectors with core rules and values, including data protection, trust in data and data governance. A common European energy data space is one of nine strategic sectoral data spaces suggested by the strategy, and it can be expected to link strongly with the mobility data space for e-mobility business cases. A common data space should act as a precondition for the successful development of artificial intelligence in Europe.

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[303] European Commission, *Powering a Climate Neutral Economy: An EU System Integration*, *COM(2020) 299 final*, July 8, 2020, https://eur-lex.europa.eu/legal-content/EN/ALL/?uri=COM:2020:299:FIN.

[304] European Commission, Directorate-General for Energy, Clément Alaton and Frédéric Tounquet, Benchmarking smart metering deployment in the EU-28 : final report, Publications Office, 2020, https://data.europa.eu/doi/10.2833/492070.

[305] European Commission, *A European Strategy for Data, COM(2020) 66 final,* February 19, 2020, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52020DC0066.

The most relevant data-space initiatives, especially in the energy sector, are Gaia-X and the International Data Spaces (IDS), as they have the largest number of collaborators, including many of the leading European companies in the field, and both are already beginning to implement use cases, see also Table 27[306].

Table 27. Overview of Gaia-X and IDS

	Gaia-X	International data spaces (IDS)
Organisation	Gaia-X European Association for Data and Cloud AISBL	International Data Spaces Association (IDSA), formerly known as Industrial Data Space Association
Founded	January 2021	February 2016
Members	Around 300 worldwide	131 worldwide
Sectors	> 10	> 7
Total use cases (Gaia-X or IDS-compliant)	> 70	> 27
Energy-related use-cases	16	> 4
Live use-cases (Gaia-X or IDS-compliant)	0	2

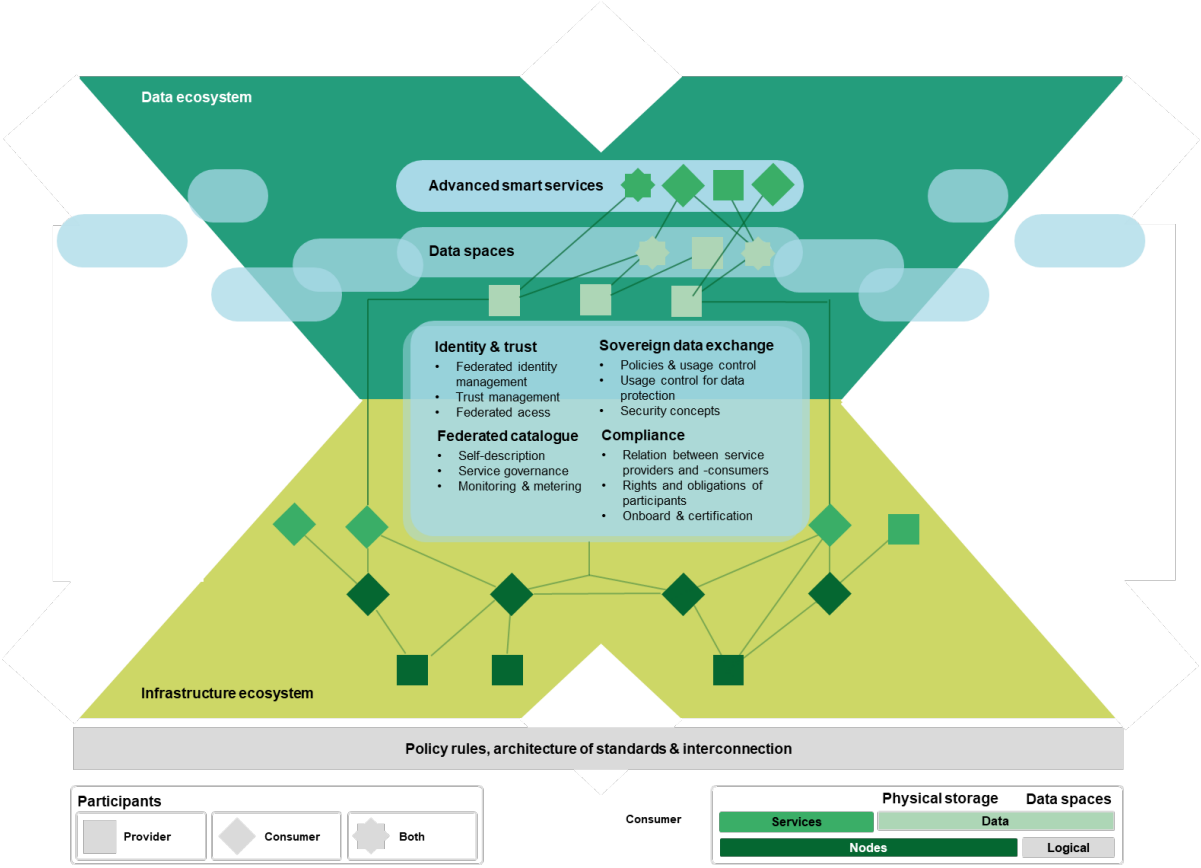
An alternative to Gaia-X and IDS is Euclidia, the European Cloud Industrial Alliance. Other cloud-based data spaces gaining traction are the UK company Icebreaker One's Open Energy pilot project and Amazon Web Service's Open Subsurface Data Universe (OSDU) standard[307].

The data ecosystem and the infrastructure ecosystem, in which data providers and data consumers interact, are core parts of the Gaia-X architecture, as shown in Figure 98.

[306] Gaia-X, n.d., https://www.gaia-x.eu/; International Data Spaces Association, n.d. https://internationaldataspaces.org/.

[307] OSDU Data Platform, Amazon Web Services, n.d., https://aws.amazon.com/de/energy/osdu-data-platform/.

Figure 98. Gaia-X architecture[308]



Three core areas have been identified within the energy use case of Gaia-X: (1) the "trusted platform and infrastructure", which should provide data sovereignty and security for users; (2) "Redispatch 2.0/3.0", which supports and improves network planning and calculation; and (3) neighbourhoods and neighbourhood solutions, which allow for consuming energy across sectoral boundaries.

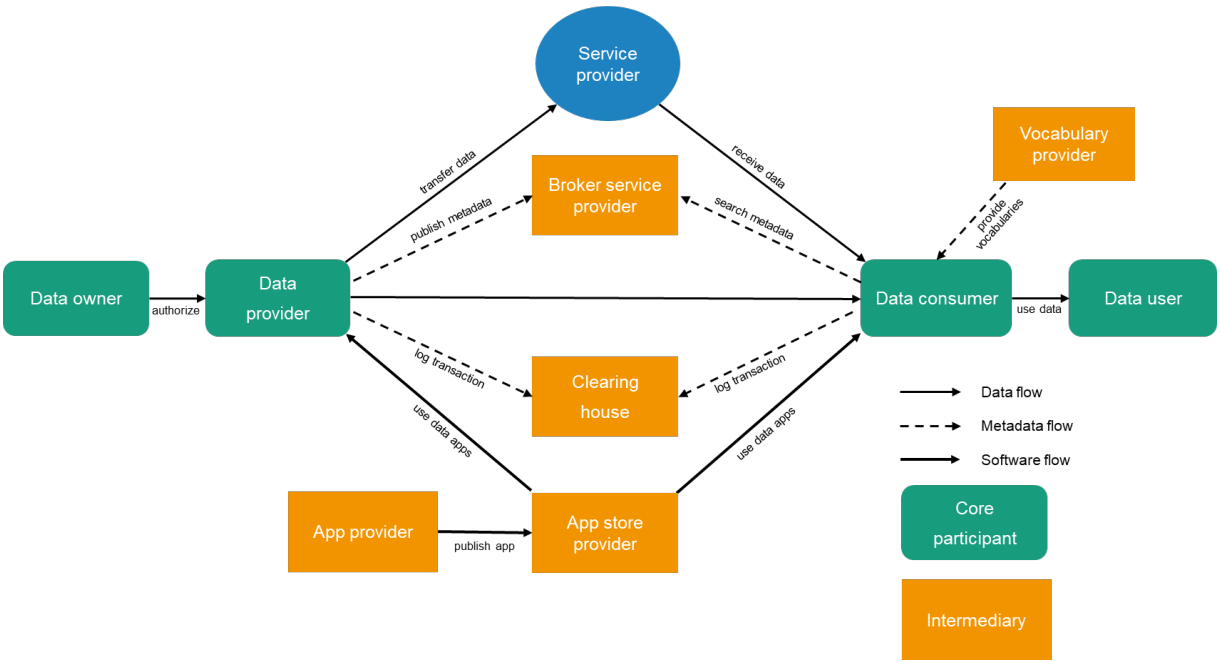
Key governance topics related to the EU's 2018 General Data Protection Regulation [309] – transparency, cybersecurity, portability and contracts – are addressed through the Gaia-X framework.

As shown in Figure 99, data providers and data consumers are building the central elements of the IDS's framework, which defines processes for intermediaries that act as service providers, offering, for example, vocabularies or apps to data consumers.

[308] Budesrepublik Deutschland Bundesministerium für Wirtschaft und Klimaschutz [Federal Republic of Germany Federal Ministry for Economic Affairs and Climate Action], Gaia-X Architecture, January 2021, https://www.researchgate.net/Figure/GAIA-X-Architecture-own-adaption-based-on-BMWI-2020-GAIA-X-Technical-Architecture_fig2_348767747; Boris Otto et al., "Gaia-X and IDS," IDSA, January 2021, https://internationaldataspaces.org/wp-content/uploads/dlm_uploads/IDSA-Position-Paper-GAIA-X-and-IDS.pdf.

[309] GDPR.EU, Proton Technologies AG, "What is GDPR, the EU's new data protection law?," n.d., https://gdpr.eu/what-is-gdpr/.

Figure 99. IDS architecture[310]

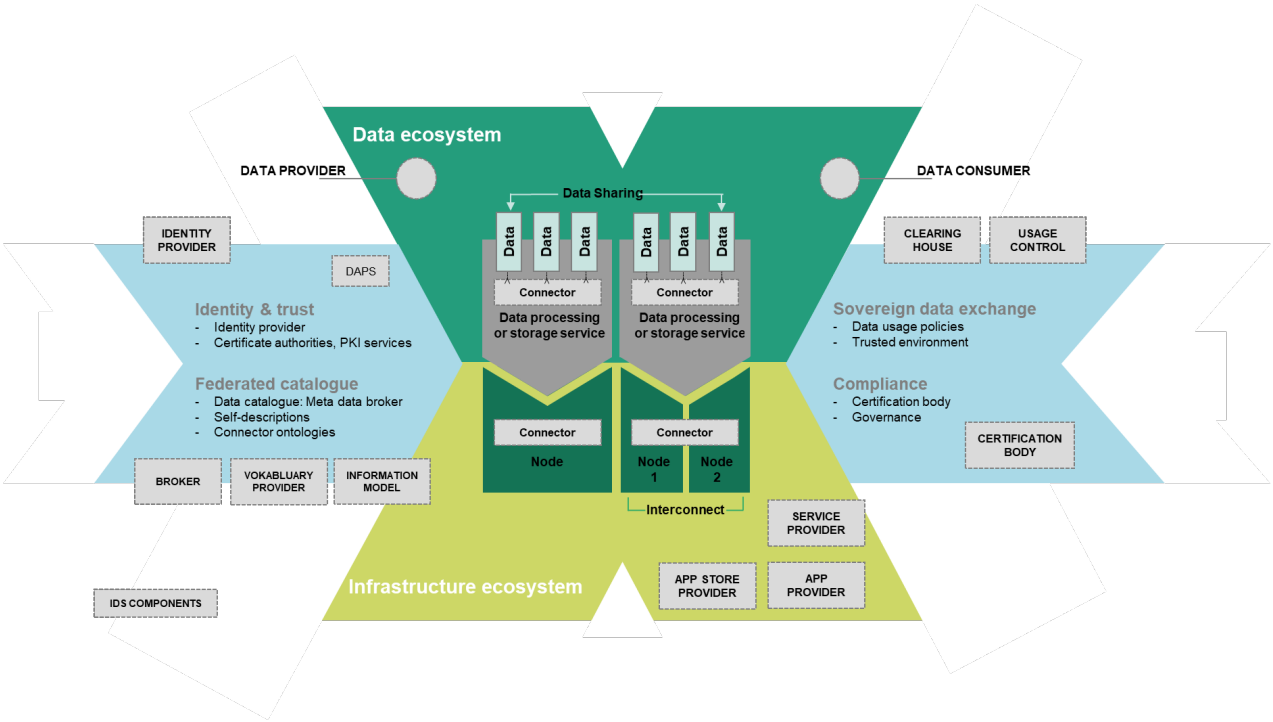


The main service areas within Gaia-X that can also be mapped to the IDS framework, as shown in Figure 100, are:

- the implementation of secure federated identity and trust mechanisms (security and privacy by design);
- sovereign data services that ensure the identity of the source and receiver of data, as well as their access and usage rights;
- easy access to the available providers (federated catalogues), nodes and services;
- the integration of existing standards to ensure interoperability and portability across infrastructure, applications and data;
- the establishment of a compliance framework, along with certification and accreditation services; and
- the contribution of a modular compilation of open-source software and standards to support providers in delivering a secure, federated, interoperable infrastructure.

[310] ISDA and IDS Reference Architecture Model (IDS-RAM) Version 3.0, IDS Roles and Interactions, January 2021, https://www.researchgate.net/Figure/IDS-Roles-and-Interactions-source-IDSA-IDS-RAM-30_fig1_348767747; Otto et al., "Gaia-X and IDS."

Figure 100. Mapping of Gaia-X and IDS architectures[311]



The IDS framework has been implemented and used for several use cases, as shown in Table 28.

Table 28. Data spaces implemented with the IDS framework

	Smart Connected Supplier Network (SCSN)[312]	Mobility Data Space[313]	Mobilithek/Mobility Data Market Place (MDM) 4.0[314]	Catena-X Automotive Network (Catena-X)[315]
Origination	Developed within the Smart Connected Supplier Network field lab beginning in 2016	Started in 2019 in Germany, coordinated by Acatech – National Academy of Science and Engineering	Joint initiative of Germany's Federal Ministry of Transport and Digital Infrastructure and the Federal Highway Research Institute	Joint initiative of research and the automotive industry, formally founded in May 2021

[311] Gaia-x and IDSA, Mapping of IDS Components into the Gaia-x Architecture, January 2021, https://www.researchgate.net/Figure/Mapping-of-IDS-Components-into-the-GAIA-X-Architecture-source-GAIA-X-initiative_fig3_348767747; Boris Otto et al., "Gaia-X and IDS."

[312] Matthjs Punter, "The smart connected supplier network by TNO," IDSA, April 23, 2020, https://internationaldataspaces.org/the-smart-connected-supplier-network-by-tno/.

[313] Mobility Data Space, n.d.. https://mobility-dataspace.eu/.

[314] MDM Portal, n.d., https://www.mdm-portal.de/?lang=en.

[315] Catena-X Automotive Network, "Catena-X Automotive Network Overview," June 1, 2021, https://catena-x.net/fileadmin/user_upload/intro_praesenationen/eng_overview_catena-x_v1.01.pdf.

	Smart Connected Supplier Network (SCSN)[312]	Mobility Data Space[313]	Mobilithek/Mobility Data Market Place (MDM) 4.0[314]	Catena-X Automotive Network (Catena-X)[315]
Supporting organisation	Netherlands company Brainport Industries	Digital rights management non-profit Datenraum Mobilität	The Federal Highway Research Institute	Catena-X Automotive Network
Core objective	Seamless supply-chain communication as part of Industry 4.0 to benefit from the fourth industrial revolution, driven by the Internet of Things and the digital transformation of industries	To foster safe and sustainable mobility concepts	To "keep things moving" by supporting transport planning, targeted traffic control and consumer choice in transportation	Support of open-source and proprietary solutions (must be IDS- and Gaia-X-compliant)
Concept	Nine service providers connect participating manufacturing companies	Combines Gaia-X and IDS, weather, infrastructure, traffic safety and environment	Version 3.0 had a large user base of 510 data providers and 330 data users as of August 2021. Uses the European standard DATEX II for exchanging mobility data DATEX II	In May 2021 the consortium included 26 research organisations; industry associations; original equipment manufacturers; tier 1, 2 and 3 suppliers; technology providers; small and medium-sized enterprises and more
Typical categories of data shared	Order information, delivery details, product data, billing data and order options	Weather, infrastructure, traffic safety and environment	Static road data or signs and traffic regulations, toll data, real-time traffic data, public transport information, bike and pedestrian networks	

	Smart Connected Supplier Network (SCSN)[312]	Mobility Data Space[313]	Mobilithek/Mobility Data Market Place (MDM) 4.0[314]	Catena-X Automotive Network (Catena-X)[315]
Use cases		More than 55, including the first pilot, an app called Free Now (formerly Mytaxi), which receives data from DWD, the German weather-forecasting service, to protect users from severe weather events		10, from product hardware and software traceability to real-time control and simulation as a shared service
Price model	Service providers pay per connected customer rather than a set fee	No fee until 2024	Registration and membership are free; data usage by contracts/licenses. Version 4.0 will arrive in spring 2022 with IDS components and the new name, Mobilithek	Catena-X is revenue-dependent and charges a membership fee

16.4 Policy conclusions

16.4.1 Recommendations on flexibility use cases

16.4.1.1 Distributed energy resource management systems

DERMS can reduce curtailment, support system stability and enable the integration of flexibility capacity from renewable energy sources. Though several member states have lowered capacity thresholds for the participation of small-scale units in congestion management and other ancillary services, participation remains low. This could be improved in three ways: (1) DERMS would be more attractive to system operators if it were recognised as a non-wires alternative for conventional grid expansion; (2) as the control and operation of DERMS require access to data from the grid and participating assets, the creation of safe and trustworthy data frameworks is a key enabler; (3) for small-scale units such as prosumers, transaction costs should be removed by implementing regulatory conditions that allow for the standardised prequalifying and participation of various stakeholders, with clearly defined roles and related processes.

16.4.1.2 Virtual power plants

Increasing shares of volatile renewable energy sources such as wind and solar also increases the need for flexibility. VPPs can bring distributed energy resources into flexibility markets. While it is necessary to substitute the use of conventional flexibility resources, obstacles preventing a level playing field include different prequalification conditions and IT regulations in different European markets and low motivation on the part of prosumers to participate. A regulatory framework that simplifies the participation of stakeholders by amending the system operation guidelines and supports the use of information and communications technology solutions would allow smaller-scale distributed energy resources to participate at low transaction costs.

16.4.1.3 Energy communities and energy sharing

Energy communities can provide incentives for investment in renewables and for flexibility activation. While renewable energy communities and citizen energy communities are clearly defined in European regulations (RED II and IEMD, respectively), the success and diffusion of energy communities depend heavily on the existence of national regulations. Analysis shows that in countries lacking national regulations and incentives, energy communities cannot compete with self-consumption schemes that have financial incentives. They are hindered by regulation hurdles like unclear energy community definitions. With incentives such as cost-reflective charges, tax refunds, lower investment risks and a market premium for surplus electricity, as well as clear and simple regulations, energy communities can allow for citizen engagement, create financial benefits and add value locally.

16.4.1.4 District heating and cooling

Including flexibility in the definition of efficient DHCs – for example, "x% flexibility-service capacity for the electricity market in relation to its heating capacity" – in several European Commission documents, including the EED and the guidelines on state aid, would facilitate investments in flexible DHCs.

RED II's definition of RECs states that they "produce, consume, store, [and] sell renewable energy". Thus, registering as a renewable energy community is a requirement for producing and consuming energy and participating in energy markets, whereas storing and selling energy (that is, flexibility support for the grid) is not included. This definition could be extended to include flexibility as a further criterion for classifying a community as a quasi-renewable energy community, opening all markets to DHC flexibility services.

According to the RED II, member states shall ensure that the national regulatory framework does not discriminate against participation in the electricity market, including congestion management and the provision of flexibility and balancing services, of small or mobile systems such as domestic batteries and electric vehicles. Such non-discriminatory participation could also include DHC if the restriction were released and DHC were added as a further flexibility supplier. Article 24, paragraph 4, refers to the contributions of DHC to energy performance and renewable energy shares. These contributions should include flexibility services for the electricity market as a measure contributing to the fulfilment of Article 23, 1, as it can increase the use of renewable energy.

Concerning the IEMD, citizen energy communities are by definition entities that engage in energy services for their members or shareholders; entities providing services to non-members and shareholders are not CECs. Non-members, such as TSOs and DSOs, could be included at least for flexibility services, so that DHCs could be classified as CECs and hence be able to access all electricity markets, including flexibility markets (Articles 2 and 17, respectively). A new Article 33.x could also

address the integration of DHC suppliers into the electricity network if they offer demand-response services.

16.4.1.5 Industrial hybrid heating

Compared with energy communities and DERMS, individual industrial processes provide a disproportionately larger flexibility potential per unit. Nevertheless, industrial flexibilities need to be strengthened in the face of competition with conventional incumbents. The regulatory framework should thus provide incentives for industrial load flexibility, or at least prevent disadvantages to it. As a basic requirement, the future regulatory design should ensure that all electricity markets be open for the participation of individual and aggregated industrial loads. Moreover, modalities for prequalification and participation, which might be based on historical specifications and the technical characteristics of incumbent players, should be aligned with market needs and be suitable for industrial flexibility resources.

16.4.1.6 Home energy management systems and residential heat pumps

For home energy management systems to provide flexibility to the grid, consumers must be willing to participate. In addition to promoting knowledge and awareness about the possibility of marketing flexibility, this requires incentives in the form of dynamic tariffs and locational pricing. The use of such tariffs requires a smart-metering infrastructure, a safe and trustworthy data framework and possibly access to data for third-party stakeholders. The regulatory framework could intensify the promotion of dynamic tariffs while also facilitating and standardising data access and management.

To realise flexibility from heat pumps and batteries, both should be able to communicate with the grid via a home- or commercial-building automation network. In practice, because all business models require the connectivity of the heat pump and batteries, home appliances are encouraged to have smart-integration features with open standards and connectivity protocols. Regulators could set up guidelines for manufacturers and supplies to implement mandatory features in heat pumps that would allow the pumps to connect to the electricity grid. Moreover, providing consumers with flexibility calculations could result in a positive shift in behavior. In addition to technical requirements, member states should offer favorable, hassle-free flexibility-market conditions for heat pump and battery users.

16.4.1.7 Smart charging and vehicle-to-grid

Regulation – particularly RED II and the IEMD and their corresponding national regulatory frameworks – should provide an enabling framework that prevents discrimination and supports incentives such as cost-reflective charges.

It is already obligatory to provide electric vehicle charging infrastructure in new and renovated buildings (EPDB Article 8). This obligation could be extended to infrastructure and devices that facilitate the use of electric vehicles as a flexibility resource. Examples are smart-charging stations and smart metering and communication infrastructure.

The flexibility potential of smart charging is limited by the energy demand for driving. This is not the case for vehicle-to-grid, which therefore offers substantial flexibility potential. Currently, the regulatory status of EV users applying V2G is unclear. The uncertainty regarding whether they are renewables self-consumers or power generators makes their participation as generators challenging; they are not yet on a level playing field with other power-generating assets, because they may be double-charged for power taxes on both EVs and V2Gs (charging and discharging). The regulatory framework should ensure that they are not discriminated against as generation

assets, and grid charges and taxation for grid feed-in must be defined in a way that avoids double charging – for example, by defining electric vehicles as generators.

16.4.2 The overall significance of flexibility

This analysis, conducted with regard to the technical and regulatory requirements for flexibility use, identified several aspects specific to individual use cases. In addition, however, there are several obstacles to the activation of demand side flexibility resources, including that demand side-resource controllability, technical requirements, market integration and incentives for participation are all lacking.

The control of demand-side resources can be subdivided into two aspects: optimising the operation and management of demand side resources and accessing real-time data. This requires functioning interfaces, communication protocols and data spaces for processing the data. Additionally, the regulatory framework should specify which kinds of data have to be made available and who is allowed access to them. Where applicable, remote control of flexibility assets should be enabled.

While this first category covers software, hardware is also required, particularly cheap and interoperable metering and control technology, which is necessary for the participation and aggregation of small-scale flexibility options.

Establishing control over flexibility assets and solving technical challenges are prerequisites for market participation. The features of flexibility resources need to be considered in the design of market conditions by rethinking market rules according to actual needs, not history. This concerns, for example, minimum bids, shorter gate closure times, shorter availability periods, comfort needs and production schedules. Participation would be facilitated if it were possible to prequalify groups of small applications (such as storage, heat pumps and electric boilers) rather than individual applications. Moreover, not only wholesale markets but also markets for system and ancillary services should be made open and accessible for flexibility resources. Open, fair, and transparent electricity markets for all end customers are an important precondition for developing flexibility use cases.

The need for incentives affects all relevant use cases. Large-scale and aggregated flexibility resources must be explicitly allowed to participate in a market and receive incentives in the form of market prices. Because prosumers and smaller-scale flexibility resources are not necessarily involved in power markets, cost-reflective tariffs – either market- or grid-oriented – are required for incentive-based activation of these flexibility resources. Knowledge gaps are more relevant for small customers, as energy is not their core focus. Incentives must be easy to use, transparent and clearly explained.

Apart from the possibility of participating, incentives originating from the power system must be sufficiently attractive. The net revenue of marketing flexibility depends to a large extent on individual asset costs and the price level on wholesale electricity markets, neither of which can be influenced easily by the regulatory framework. However, because other factors, such as transaction and IT costs and the design of fiscal charges, can affect the profitability of demand side flexibility, the design of the future regulatory frameworks should take these into account.

From these key barriers, it can be assumed that regulatory and policy documents should, in general, recognise the value of flexibility for renewable integration. This could be done by emphasising flexibility on the same level as RES deployment and energy-efficiency gains. Flexibility readiness should be an overarching aim for all flexibility use cases in order to allow for easier integration of flexibility in the future. Emerging use cases like smart charging, flexibility from electrical district heating and industrial flexibility are promising in this regard.

With an increasing number of flexibilities, particularly small-scale flexibilities, the need for easy-to-access, secure, standardised data frameworks increases as transaction costs for monitoring and controlling flexibility assets play a much bigger role. Solutions typically must be provided for the full value chain (that is, to allow for flexibility use cases like smart charging and V2G, for example). This is difficult to provide for small and medium-sized enterprises if they cannot rely on existing data-exchange frameworks. Opening data access to a larger number of enterprises can also stimulate innovations, but only for parts of the value chain, such as those related to analytics, forecasting and optimisation. Currently, sharing and exchanging data can be difficult if the data can only be used by operators that collect it (for example, if only charge-point operators and original equipment manufacturers have data on EVs' charging behavior and charging locations). Safe and trustworthy data exchange is also needed to provide data to third parties and could become a foundation for developing and training data-driven applications and solutions.

Overall, analysis suggests that the provision of flexibility services would contribute strongly to a carbon-neutral energy system.

17 International and intersectoral experiences

This report seeks to share the challenges the power industry is facing and the perspective of the European Commission as a policy shaper by reviewing how the 14 business cases discussed are developing in the real world. (See Appendix A for synopses of the 14 business-case analyses.)

To do that, the report evaluated more than 100 companies offering one or more services related to energy flexibility. These companies include equipment manufacturers, utilities and software developers. Analysis focused on relatively young companies and start-ups, given their track record to disrupt industries, and chose 10 digital use cases that have the potential to shape the industry, through either the flexibility they are expected to provide or their commercial viability. (See Appendix B for a full list of the companies evaluated.)

Use and business cases were reviewed from a wide variety of companies in the sector, both within and outside the European Union, and they were viewed through the lens of some innovative business models being developed outside of the energy-flexibility ecosystem that could be instructive for the energy sector.

The use cases were assessed in terms of potential impact, technology, market, application, and infrastructure and regulatory requirements:

- *Potential impact* refers to the expected economic, environmental, social and business value of the use case.
- *Technology* is the combination of hardware and software required to deliver the use case.
- *Market* refers to the specific niche or segment of the power industry targeted by the use case.
- *Application* is value creation through the use of open or proprietary data, software and hardware.
- *Infrastructure and regulatory requirements* refer to the minimum supporting regulatory and physical infrastructure required to replicate the business case.

Below are example applications of how three of the business cases were applied in the real world. Each either shows innovative digital applications directly helping power systems become more flexible while reducing energy consumption, or examines a relevant application from beyond the energy sector. These examples do not necessarily reflect the three most promising or viable companies based on our outside-in view in this assessment:

- *Company A's load-optimisation solution.* EU-based Company A developed an app that automatically optimises the charging moments for electric vehicles, with the goal of lowering the cost of consumed electricity. The app tracks the energy market in real time and uses algorithms to select the best hours to charge electric vehicles, allowing consumers to save 30% to 50% on energy bills. The company plans to expand to other electrical appliances, including water heaters and heat pumps; however, no timeline has been specified.
- *Company B's smart-building applications.* Company B is a start-up, also based in the European Union, that specialises in smart building solutions and helps reduce industrial and commercial energy consumption by optimising HVAC usage, resulting in savings of 30% to 40% for average heating and cooling bills of less than EUR 45,000 a year. The company installs a plug-and-play monitoring device with sensors that regulate ventilation, heating and cooling in real time based on reference parameters for temperature, humidity and other factors. The collected data is used for low-cost system optimisation using cloud-based algorithms. The system can also be used to maintain comfort levels while supporting grid-balancing to reduce peak demand.

- *Company C's smart-city project.* Asia-based Company C supported local government with the objective of improving the performance of public infrastructure using big-data computing and neural networks technology. Processing massive amounts of data from sensors trained on traffic, Company C's smart-city project has cut commutes by three minutes, increased travel speeds by 15% (up to 50% for emergency vehicles) and increased passenger volumes on bus routes by more than 15%, reducing overall city congestion. Although the project is not yet related to the energy sector, this example shows the importance of close collaboration between various public and private entities, as well as the benefits of international collaboration.

This evaluation resulted in several findings relevant to branches of governments like the European Commission, agencies institutes and research organisations.

17.1 Fast-paced policy implementation

To keep up with technology and business innovations, regulatory and policy decision-makers also need to consider their ability to respond at speed.

For example, the penetration of residential and commercial electricity-monitoring smart meters currently varies widely across EU member states. That variation is driven not only by speed of action (for example, Italy has been pushing for adoption since the 2000s) but also by the ramping-up pace (Denmark, for instance, has reached nearly 100% smart-meter adoption, having started its public-messaging campaign in 2014). Similarly, VPPs have been adopted in Germany and parts of the United States, such as California, much faster than in regions where regulation has not been able to keep pace.

17.2 Policy design with new technology and digital business models in mind

Governments looking to design effective policies with new technologies and digital business models in mind will consider the innovative journey that digitally based business models will take in the decades to come rather than prolonging regulations designed around a loosely comparable analog world.

Failing to consider the pace of innovation may have a negative impact on the development of business models leveraging new technologies and digital applications – and therefore on the accompanying ecosystem of businesses required to develop such technologies and applications. A good example of this is the regulation developed in the United States relating to battery storage, which helped total grid-connected battery installations reach about 1.65 gigawatts by 2020, with an additional pipeline of at least 10 gigawatts expected by 2023[316]. This regulation includes the Federal Energy Regulatory Commission's 2013 mandate to market operators to simplify the grid connection process for battery storage, and the development of tariffs and market rules that properly recognise the "physical and operational characteristics of electric storage resources," including their capability to provide capacity, energy, and ancillary services in the regional transmission organisations and independent system operators markets.[317] Treating battery storage as a generation-only unit could place an undue burden on this new technology by limiting its application (and therefore its profitability) and could slow innovation in the form of non-wire alternatives.

[316] US Energy Information Administration, "US large-scale battery storage capacity up 35% in 2020, rapid growth set to continue," Today in Energy, August 20, 2021, https://www.eia.gov/todayinenergy/detail.php?id=49236.

[317] US Energy Information Administration, "Battery storage in the United States: An update on market trends," Analysis & Projections, August 16, 2021, https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage_2021.pdf.

17.3 Cross-government coordination and support

Government entities could improve outcomes by coordinating regulation and helping support new activities.

Many new technologies and business models are blurring the lines of responsibility between various public entities, which may require policymakers, more than ever, to adopt a coordinated approach to regulation, enforcement and support. For example, the regulations and incentives for electric vehicles in Norway (which has one of the highest EV penetrations in the world) involve four levels of government: the Ministry of Climate and Environment, which requires zero emissions in passenger cars and will add light vans to that requirement in 2022; the Ministry of Transport and Communications, with its National Transport Plan 2018–2029, which requires all new passenger and light commercial vehicles to be zero-emissions by 2025; central government, which is financing the establishment of at least two multi-standard fast charging stations every 50 kilometres on all main roads; and local governments, which are limiting EV rates on local ferries, toll roads and so forth to no more than half of the tariff for internal combustion engine vehicles.

17.4 International cooperation

Policies that are built through international cooperation can be more effective than those that focus on local or regional needs alone.

Policymakers who take an open approach to trends in other regions can learn from best practices and the experience of other governments. This approach has begun in emerging markets, where technology adoption lags behind developed markets. For example, a collaboration between the German Federal Ministry for Economic Cooperation and Development and India's Ministry for New and Renewable Energy that started in 2006 has helped develop regulatory frameworks and pilot programmes for rooftop solar projects in India[318]. Such partnerships ensure that markets can learn from one another and that mistakes can be minimised.

[318] Jörg Gäbler, "Indo-German solar energy partnership (IGSP)," GIZ, n.d., https://www.giz.de/en/worldwide/76413.html.

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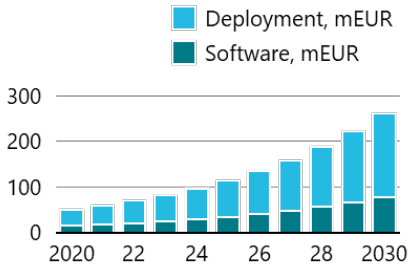
A.1 Appendix A Business-case summaries

Business case 2.1: Distributed energy resource management systems

To achieve decarbonisation targets as set out in the European Green Deal and Fit for 55 package, integration of distributed energy resources (DER) such as small-scale solar, wind, batteries, electric vehicles and so forth at scale is required. At high levels of DER, DERMS can help reduce curtailment and intelligently manage the grid-edge resources from a system-stability perspective.

This business case looks at the requirements and challenges for DERMS, which does not provide power flexibility itself, as an enabler for integrating flexibility capacity. DERMS are typically integrated into overarching advanced distribution management systems (ADMS), which are used by distribution system operators (DSOs) to optimise their operations end-to-end. ADMS are excluded from this business case.

Impacts

Systemic impacts	Societal impacts	Economic impacts
DERMS help Distribution System Operators (DSOs) to manage DER at scale and support the end-to-end operational activities. An intermittent renewable-energy threshold of 30% is the indicative level at which DSOs require DERMS to integrate even higher levels of RES, but no quantified impact on curtailment reduction or DER uptake acceleration has been publicly reported. DERMS also integrates end-to-end operational activities for DSOs, which can lower the barrier for other flexibility business cases like virtual power plants and energy sharing communities.	DERMS helps find non-wires alternatives to expanding the power grid capacity, reducing impact from infra projects on communities. DERMS can have an indirect positive impact on the renewable energy source (RES) installation job market, through the ability to integrate higher levels of RES into the grid. DERMS enable better control of grid stability at higher levels of RES, benefiting governments, DSOs and consumers. DERMS may have a negative impact in that it increases the power infrastructure's exposure to cyber attacks	Potential market size for DERMS is obtained from market research by Guidehouse. For DERMS as a flexibility enabler, the approach to market-size estimation deviates from that of business cases that provide actual flexibility capacity. **EU-27 potential market size**  **Approximate cost of flexibility** Assuming DERMS require integration existing into ADMS systems and carry part of the cost of that integration Capital expenditure: EUR 1,000 to EUR 1,400 per megawatt year. Operating expenses: EUR 140 per megawatt Total Cost of Ownership: EUR 1,140 to EUR 1,540 per megawatt year

Feasibility

As DERMS themselves do not add or limit flexibility performance, no technical assessment is made for them. The ability to provide flexibility depends on the business cases that are integrated through DERMS, such as VPPs, vehicle-to-grid, and so forth.

Flexibility market

● Covered ○ Not covered

- ● Wholesale/spot market
- ● Congestion
- ● Ancillary services

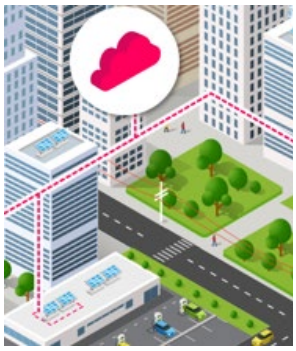
DERMS enables the integration of high levels of RES and flexible DER. It does not provide flexible power capacity itself.

EC policy area(s) X Covered X Not Covered

- Climate action
- Sustainable mobility
- Clean energy
- Farm to fork
- Circular economy
- Biodiversity
- Building and renovation
- Zero pollution

Players in the global DERMS market include Hitachi ABB (Switzerland), General Electric and Autogrid (USA), Schneider Electric (France) and Enbala (Canada). All have medium global market share.

Business case 3.1: VPPs for intraday spot market



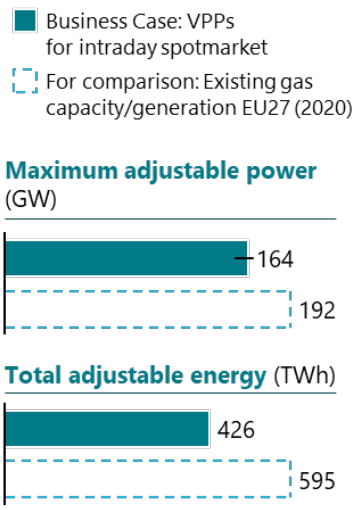
Virtual power plants (VPPs) can help achieve decarbonisation targets as set out in the European Green Deal and Fit for 55 package by bringing distributed energy resources (DER) into flexibility markets. The more intermittent renewables such as solar and wind power are used, the greater the need for flexibility in the energy system. Renewable energy is usually generated by a large number of distributed devices that must be aggregated to participate economically in flexibility markets, and VPPs answer that need. Spot, or wholesale, market flexibility balances supply and demand on a 15-minute time scale and offers a better price per megawatt hour than baseload power generation, which provides for the minimum level of energy required by an electrical grid over a set span of time.

This business case includes only economically dispatchable renewable generation like pumped hydroelectric power and small combined heat and power plants (CHP) that use biomass or gas for fuel. Solar, wind, batteries and large-scale hydro are excluded. As units like CHP can also provide baseload power and heat, we assume CHP plants to be present and not purpose-built for flexibility.

Impacts

Systemic impacts

The dispatchable capacity from VPPs in European Union is projected to be 360 gigawatts by 2050. The top-three VPP applications – internal balancing, balancing reserves and intraday spot market trading – cover 260 gigawatts, and VPP operators will apply them in that order based on price differences and obligations. VPPs for the spot market are expected to contribute 164 gigawatts capacity by 2050. The Figure below compares the contribution of VPPs for intraday spot market with conventional gas generation in the European Union in 2020.



Societal impacts

Europe is in the leading position regarding generation based VPP developments.

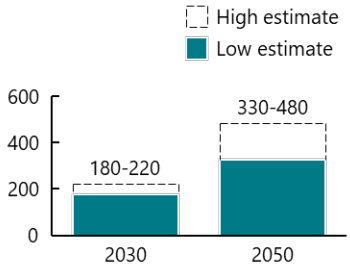
VPPs enables better control of grid stability control with higher levels of renewable energy, benefiting governments, distribution system operators (DSOs) and consumers.

A possible downside is that VPPs can increase exposure of power infrastructure to cyber threats

Economic impacts

Potential market size (mEUR/year) is calculated from operator Total Cost of Ownership (EUR/MW-year) and projected capacity uptake (MW). TCOO is the total cost of annualized CAPEX and OPEX

EU-27 potential market size, mEUR

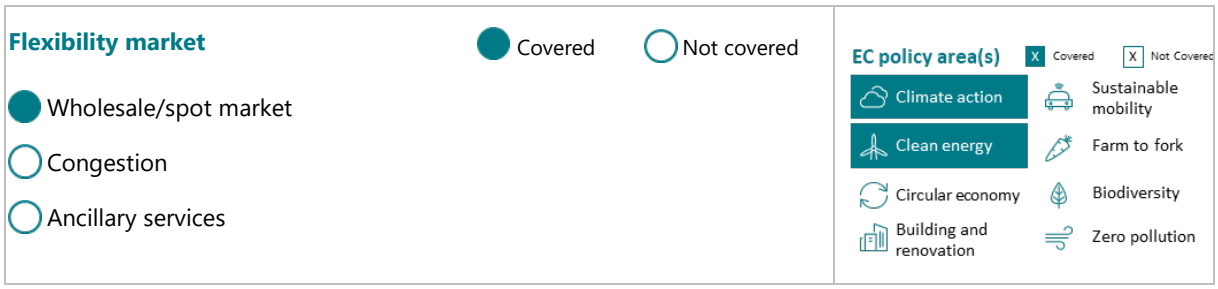


The approximate cost of flexibility, considering a range of VPP sizes in terms of both capacity and number of DERs), is estimated to be EUR 2,950 per megawatt year, based on the following calculations:

Capital expenditure: EUR 15 to EUR 35 per megawatt year

Operating expenses: EUR 1,000 to EUR 4,900 per megawatt year

TCOO: Approximately EUR 1,000 to EUR 4,900 per megawatt year (average: EUR 2,950)



Players in the European VPP market include dedicated VPP developers such as Next Kraftwerke and established power generators like Statkraft, E.on, Enel and Enel X. Smaller players are established power-system OEMs including ABB, Honeywell, Siemens and Schneider Electric. Virtually all companies in the current EU VPP market are European.

Feasibility

Near-term maturity: The European market for VPPs participating in the intraday spot markets is expected to be mature by 2030. VPP participation on the wholesale/spot market is already commonplace in several EU countries. Currently Germany has the only mature, transparent VPP market and Germany alone is expected to make up one third of the total EU VPP market before 2030. UK and France follow in terms of market maturity.

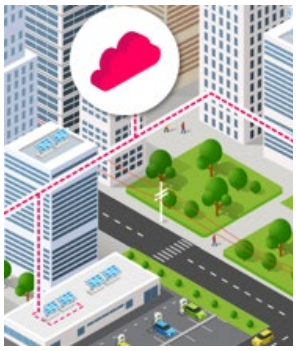
Commercial attractiveness: Analysis suggests moderate challenges in the viability of VPP participation in the spot market. VPP participation in power markets is mature in Germany, the UK and France. Viability is highly dependent on differences in power price spread, fees and taxes across EU member states. While revenues appear positive, this assessment is highly uncertain because it's difficult to estimate underlying power prices.

Technical infrastructure requirements: Analyses suggest moderate technical infrastructure challenges to delivering VPP flexibility. Focusing on a few core standards can decrease the cost of integrating DERs into VPPs. A Europe-wide high-performance information and communications technology (ICT) network could enable large-scale deployment of VPPs.

Risk considerations: Existing cybersecurity standards and regulations have so far kept the risks low and are expected to be kept up to date. Nevertheless, the increasing interaction between operational and information technologies could benefit from introducing new concepts like the resilience approach, which copes with disruptive events so that the system will not collapse and returns to a normal state when the pandemic is over.

Gamification potential: Risk could arise if overall generation capacity were concentrated in a few VPPs. Monopolies could arise to collaborate on intraday prices. One such agreement already took place, in the early 2000s. Regarding balancing reserve VPPs, without an energy price cap for frequency restoration reserve (FRR), very high prices could have an impact on other rates, such as those for imbalance settlements. This situation led to an abuse of the FRR market system in Germany in 2017.

Business case 3.2: VPPs for balancing reserves



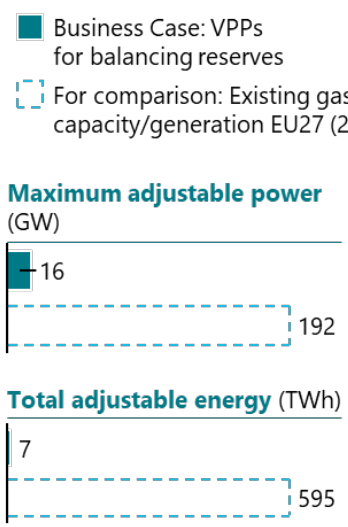
To achieve decarbonisation targets as set out in the EU's Fit for 55 and EU Green Deal, virtual power plants (VPPs) can help by bringing distributed energy resources (DER) into flexibility markets. An increased need for flexibility arises from increasing levels of intermittent renewables (solar, wind). VPPs enable small scale dispatchable RES to participate in flexibility markets. Ancillary services help stabilise the grid and market participation offers a better price per MW compared to VPP capacity for spot market or baseload power. Dispatchable RES in VPPs (not large scale, like reservoir hydro) are best suited for secondary reserves provision.

This business case (BC) includes only economically dispatchable renewable generation like pumped hydro and combined heat and power plants (CHP) like biomass, waste incineration and small gas fired plants. Solar, wind, batteries and large-scale hydro are excluded. As units like CHP can also provide 'baseload' power and heat, we assume CHP plants to be present and not purpose-built for flexibility.

Impacts

Systemic impacts

The dispatchable capacity from VPPs in EU is projected to be 360 GW by 2050. The top-3 applications cover 260 GW: based on price differences and obligations, VPP operators will logically apply this capacity first to internal balancing obligations (BC 7.5, 80 GW), then ancillary services (this business case, 16 GW) and lastly for trading on the spot market (164 GW by 2050).



Societal impacts

Europe is in the leading position regarding generation based VPP developments.

Possibly many DER will integrate into VPPs, creating significant job opportunities.

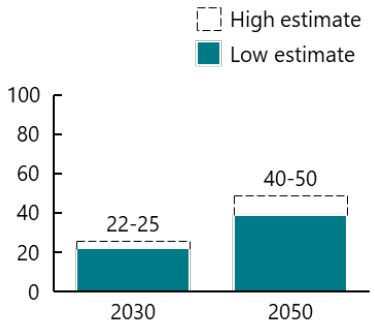
VPPs enable better grid stability control at higher levels of RES, benefiting governments, DSOs and consumers

On the other hand, VPPs increase the exposure of power infrastructure to cyber threats.

Economic impacts

Potential market size (mEUR/year) is calculated from operator Total Cost of Ownership (EUR/MW-year) and projected capacity uptake (MW). TCOO is the total cost of annualised CAPEX and OPEX.

EU-27 potential market size, mEUR



Cost of flexibility (2021), considering a range of VPP sizes (capacity and number of DER), is estimated to be:

Capital expenses: EUR ~35–70 per megawatt and operating expenses: EUR ~1,000–4,900 per megawatt year

Total cost of ownership: EUR ~1,000–5,000 per megawatt year

Average TCOO of EUR 2,950 per megawatt year is used for market size estimation

Flexibility market	Covered	Not covered
Wholesale/spot market		
Congestion		
Ancillary Services	●	

EC policy area(s)	X Covered	X Not Covered
Climate action	Sustainable mobility	
Clean energy	Farm to fork	
Circular economy	Biodiversity	
Building and renovation	Zero pollution	

Players in the European VPP market include dedicated VPP developers such as Next Kraftwerke and established power generators like Statkraft, E.on, Enel and Enel X. Smaller players are established power-system OEMs including ABB, Honeywell, Siemens and Schneider Electric. Virtually all companies in the current EU VPP market are European.

Feasibility

Near term maturity: Same as BC 3.1.

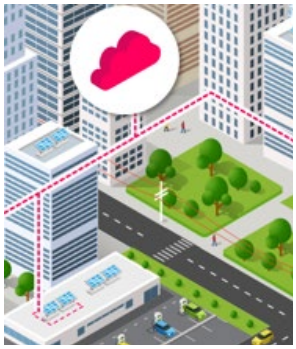
Commercial attractiveness: Our analyses suggest high challenges in estimating the revenues from balancing reserve markets. While the revenues look positive, this assessment is highly uncertain since it's difficult to estimate underlying power prices and revenue estimates are simplified, focusing only on balancing reserve revenues and ignoring cannibalisation effects within and across business cases. Furthermore, common FRR dimensioning is expected to significantly reduce demand for FRR in coming years.

Technical infrastructure requirements: Overall, there will likely be low challenges in VPPs providing balancing reserves. This is a mature application in frontier VPP markets like Germany. Scale-up across Europe may emerge in line with general VPP uptake.

Risk considerations: Same as BC 3.1.

Gamification potential: Same as BC 3.1

Business case 3.5: VPPs for internal balancing



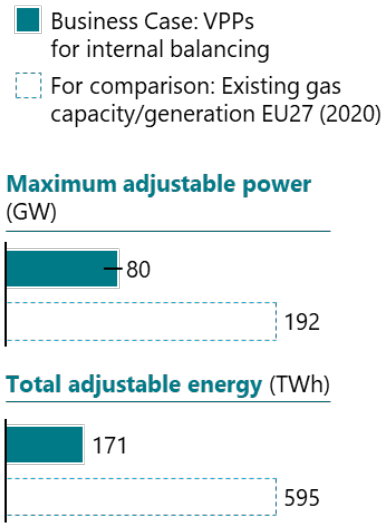
To achieve decarbonisation targets as set out in the EU's Fit for 55 and EU Green Deal, virtual power plants (VPPs) can help by bringing distributed energy resources (DER) into flexibility markets. An increased need for flexibility arises from increasing levels of intermittent renewables (solar, wind). Economically dispatchable, renewable power is currently often too small to participate in flexibility markets, and aggregation through VPPs enables such participation. Internal balancing ensures power generating companies deliver the power as agreed in day-ahead markets. Internal balancing is critical as wind and solar carry uncertainty due to weather dependency.

This business case (BC) includes only economically dispatchable renewable generation like hydro (pumped, reservoir) and combined heat and power plants (CHP) like biomass, waste incineration and small gas fired plants. Solar, wind and batteries are excluded.

Impacts

Systemic impacts

The dispatchable capacity from VPPs in EU is. The dispatchable capacity from VPPs in EU is projected to be 360 GW by 2050. The top-3 applications cover 260 GW: based on price differences and obligations, VPP operators will logically apply this capacity first to internal balancing obligations (this business case, 80 GW), then ancillary services (BC 7.2, 16 GW) and lastly for trading on the spot market (164 GW by 2050).



Societal impacts

Europe is in the leading position regarding generation based VPP developments.

Possibly many DER will integrate into VPPs, creating significant job opportunities.

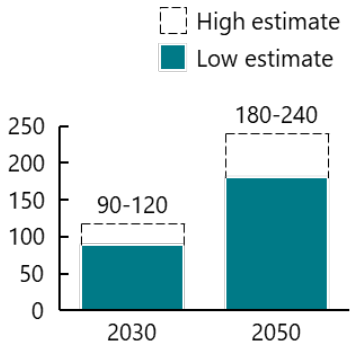
VPPS enable better grid stability control at higher levels of RES, benefiting governments, DSOs and consumers

On the other hand, VPPs increase exposure of power infrastructure to cyber threats.

Economic impacts

Potential market size (mEUR) is calculated from operator Total Cost of Ownership (EUR/MWYE) and projected capacity uptake (MW). TCOO is the total cost of annualised CAPEX and OPEX.

EU-27 potential market size, mEUR



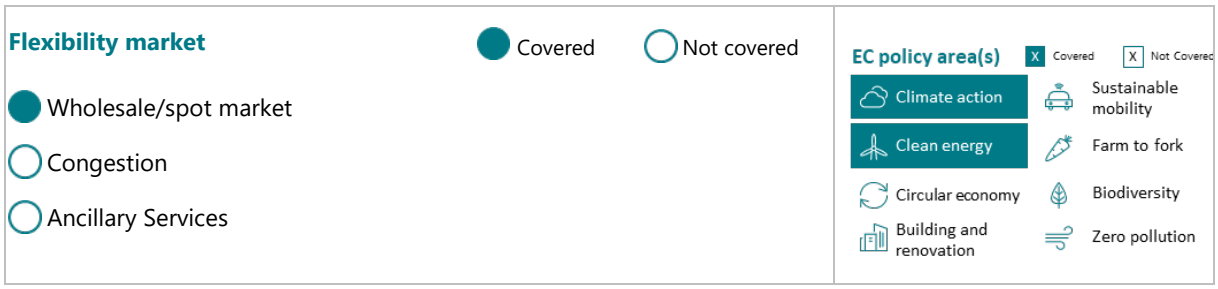
Cost of flexibility, considering a range of VPP sizes (capacity and number of DER), is estimated to be:

Capital expenses: EUR ~15–35 per megawatt year

Operating expenses: EUR ~1,000–4,900 per megawatt year

Total cost of ownership: EUR~1,000–4,900 per megawatt year

Average TCOO of EUR 2,950 per megawatt year is used for market size estimation



Players in the European VPP market include dedicated VPP developers such as Next Kraftwerke and established power generators like Statkraft, E.on, Enel and Enel X. Smaller players are established power-system OEMs including ABB, Honeywell, Siemens and Schneider Electric. Virtually all companies in the current EU VPP market are European.

Feasibility

Near term maturity: Same as BC 3.1. Mature market foreseen for 2030: Internal balancing using VPPs is commonplace in selected EU countries. Germany is currently the only mature, transparent VPP market and is expected to make up about one third of the total EU27 VPP market before 2030

Commercial attractiveness: This business case generates no revenue but reduces cost in case of noncompliance with day-ahead volumes as agreed. Estimation of avoided cost is however highly uncertain due to price projections, additional taxes, fees and other effects.

Technical infrastructure requirements: Same as BC 3.1.

Risk considerations: Same as BC 3.1.

Gamification potential: Negative: VPP operators could bet on low settlement prices and accept a penalty instead of fulfilling generation capacity, if not obliged to do so by legislation.

Business case 4.1: Energy sharing communities and peer-to-peer trading

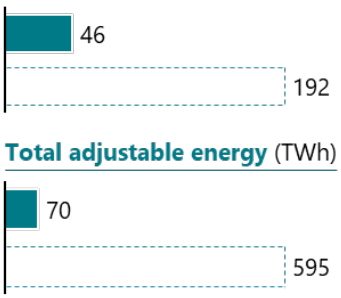
Residential power consumption is a significant share of overall energy and electricity consumption. Energy communities and peer-to-peer (P2P) trading can contribute to the EU's Fit for 55 and the Green Deal by locally trading energy surpluses and storing excess energy for later use or trading. The main focus of this business case is the use of stationary batteries for energy communities and P2P trading (which can take place within energy communities) with participants called 'prosumers'.

This business case includes P2P trades (different conditions each trade) and energy communities as whole (single trade agreement), due to similarity in energy flows. This BC differs from VPPs in that flexibility is settled within the community as priority, not the spot market. This business case excludes households (with battery) that do not participate in energy-sharing communities, battery electric vehicles (covered in BC 8.3) and energy trading between small enterprises or public entities.

Impacts

Systemic impacts

An estimated 44m prosumers will participate in energy communities by 2050. The corresponding maximum adjustable power from stationary batteries is 46 GW, and based on 1500 hours per year participation, total adjustable energy 70 TWh.



Societal impacts

Applied at scale, significant opportunity to reduce grid load through trading locally generated power within energy communities

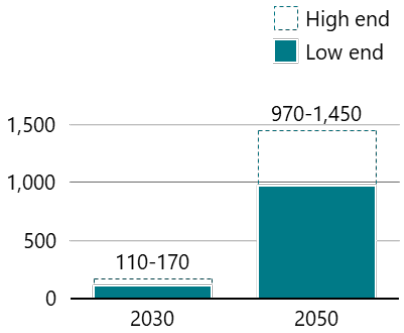
Research shows prosumers feel stronger sense of community through participation

Energy sharing increase energy inequality by lower energy cost for those that can afford PV + battery

Economic impacts

Potential market size (mEUR) is calculated from operator Total Cost of Ownership (EUR/MW-year) and projected capacity uptake (MW). TCOO is the total cost of annualised CAPEX and OPEX.

EU-27 potential market size, mEUR



Cost of flexibility (2020 battery capacity prices):

CAPEX: EUR ~20,000–31,000 per megawatt year

Operating expenses: EUR ~5,000–7,500 per megawatt year

Total cost of ownership estimated at EUR ~25,000–38,000 per megawatt year

A learning rate of 19% is observed: cost is projected to continue to fall

Flexibility market	Covered	Not covered
Wholesale/spot market	●	
Congestion		○
Ancillary Services		○

EC policy area(s)	Covered	Not Covered
Climate action	X	
Clean energy	X	
Circular economy		X
Building & renovation	X	
Sustainable mobility		X
Farm to fork		X
Biodiversity		X
Zero pollution		X

Players in the European market for stationary batteries include Sonnen (Germany), LG Chem (South Korea) and BYD (China).

Near term maturity: Energy sharing in energy communities is currently only done in pilot projects. Small and medium-sized companies are developing software solutions for which commercial status is expected in 2030.

Commercial attractiveness: Analysis suggests a high level of challenges are likely. The viability of energy communities from a revenue perspective is highly dependent on national regulatory frameworks in terms of taxes and fees. The viability is cost driven by battery CAPEX and while this is expected to continue to fall, overall profitability is highly uncertain; based on US pilot data, profitability may not be possible. The upper limit of the revenue estimate is based on simulations, indicating possibly large potential but highly dependent on fees, taxes and other effects.

Technical infrastructure requirements: The challenges of technical assessment appear to be low. Batteries outperform other energy technologies regarding technical performance relevant for power flexibility assessed here. Improvements are expected in terms of durability, degradation rate, energy density, cost and efficiency.

Risk considerations: It is possible players will experience moderate challenges in addressing the risks of energy communities. High technical risks like cybersecurity can be resolved using available technology, but more significant effort may be required to consider regulations and taxes and fee structures for energy communities to function well at scale.

Gamification potential: If energy is not traded transparently, power and cost optimisation for households could be used to act against the community system for individual financial gain. A similar principle has been observed at scale in balancing responsible parties, or companies responsible for maintaining supply and demand on the energy market, where a last-minute import from abroad was required due to a significant negative deviation from the balance in Germany's power market in June of 2019.

Business case 4.4: District heating and cooling

Residential heat demand is a significant share of overall energy consumption. District heating and cooling (DHC) networks can contribute to Fit for 55 and the Green Deal in two ways: Decarbonisation through electrification of heat generation and power flexibility to balance the power grid.

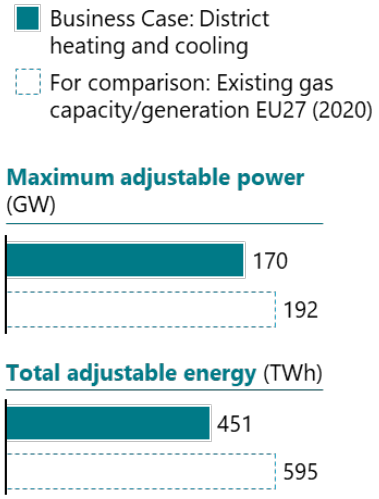
This business case focuses on flexibility provided by two means. Firstly, through significant electrification of heat generation (using heat pumps, boilers or combinations) with storage capacity, to disconnect heat demand and power load. Secondly, flexibility from combined heat and power plants (CHP, using natural gas or hydrogen) for ancillary services and power generation. While the former can be retrofitted into traditional district heating networks (high temperature, centralised heating), we assume all DHC grids that provide flexibility to the power grid will be at least 4th Generation DHC (low heating temperatures, high insulation standards).

Excluded are decentralised sources like direct solar heating, data center waste heat etc. and construction or expansion of the grid.

Impacts

Systemic impacts

The maximum adjustable power is based on the heat generation mix and size of buffer capacity such that loads can be shifted. Maximum shiftable heat demand is assumed around 75%, which means most of peak capacity demand can be delayed for later use if requested or incentivised to do so



Societal impacts

Applied at scale, DHC have significant opportunity to decarbonise residential heating

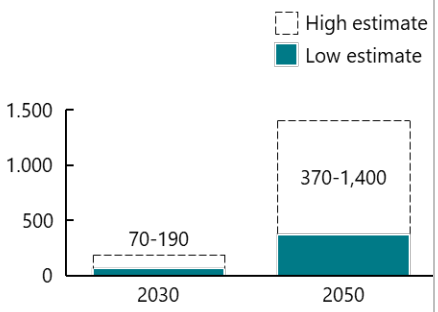
DHCs may allow for retrofitting and as such increase local RES integration

DHCs with flexibility can support systems innovation and new business model innovation

Economic impacts

Potential market size (mEUR) is calculated from operator Total Cost of Ownership (EUR/MW-year) and projected capacity uptake (MW). TCOO is the total cost of annualised CAPEX and OPEX

EU-27 potential market size, mEUR



Cost of flexibility (thermal storage systems, 2021) excluding possible cost reduction from standardisation across Europe:

Total cost of ownership estimated at EUR ~5,500-11,000 per megawatt year

~90% of this is annualised capital cost for buffer volume of EUR~90.000 per megawatt

Flexibility market	Covered	Not covered
Wholesale/spot market	●	
Congestion		○
Ancillary Services	●	

EC policy area(s)	Covered	Not Covered
Climate action	X	
Clean energy	X	
Circular economy		X
Building & renovation	X	
Sustainable mobility		X
Farm to fork		X
Biodiversity		X
Zero pollution		X

Selected large DHC operators in the EU include Vattenfall (Sweden), Engie (France) and PGNiG Termika (Poland).

Feasibility

Near term maturity: High feasibility; Most of the projects on DH providing flexibility are pilots of local application. Several companies already commercially offer flexibility as part of "smart district heating", these are mostly concentrated in the Nordics.

Commercial attractiveness: Analysis suggests few challenges for DHC operators in successfully monetising the power price spread. This is reflected in a significant projected margin, though fees, taxes and other additional expenses might reduce this significantly.

Technical infrastructure requirements: Analysis indicates low challenges in the technical aspects of leveraging energy flexibility from district heating, though its contribution to frequency stability services is limited to CHP and load reduction.

Risk considerations: Moderate risks, which need significant resolution effort are regulatory, cybersecurity, public acceptance and gamification potential. Lack of standardisation is a challenge from regulatory aspect. A 2017 cyberattack to the Naestved District Heating in Denmark shows the possible vulnerability of DHC as part of critical energy infrastructure. Lower risks include compliance regarding permitting, use of network data and use of client data (data privacy).

Gamification potential: Longer-term flexibility compared with other industry players might risk gamification. Particularly within a small grid area with limited interconnections (the area of a specific DSO, say), a DHC operator might have sufficient maximum load and flexibility capacity to manipulate the market. For example, the operator could sap all remaining flexibility from the system to profit from high flexibility prices during periods of high grid load.

Business case 5.1: Building energy management systems

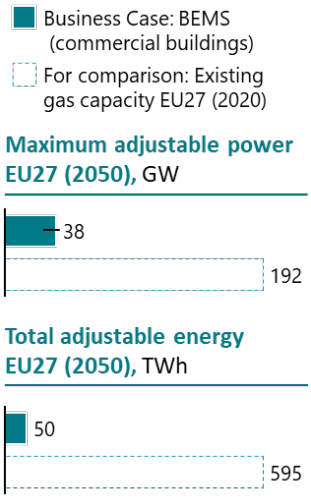
Commercial heating, ventilation and air conditioning (HVAC) demand has a significant share of the overall final energy consumption in the EU. This business case focuses on flexibility provided by shifting the BEMS HVAC demand and power load.

In the potential impact analysis, the building thermal mass is used as a thermal storage and the ventilation time constant is used to determine the flexibility potential of the ventilation system. To do so, we have modelled 6 commercial building types in four different European location. By considering the daily mean outside temperature and several different building refurbishment standards, the flexibility potentials offered by the building thermal mass were quantified for a selected EU-27 scenario up to year 2050. By adding water-based thermal storage (wherever technically possible) the flexibility potential can be adjusted depending on the size of the storage and heat pump (incl. chiller) capacity. The ventilation time constant (time required for one full air change) are used to calculate the flexibility of the ventilation system.

Impacts

Systemic impacts

The maximum adjustable energy in 2050 will vary between 41.9 and 50.4 terawatt hours, with the resulting flexible electric capacity of heat pumps ranging between 14.3 and 17.2 gigawatts. Adjustable power provided by the ventilation system will reach 21.3 gigawatts, with the maximum adjustable power from heat pumps and ventilation varying between 32.6 and 38.5 gigawatts



Societal impacts

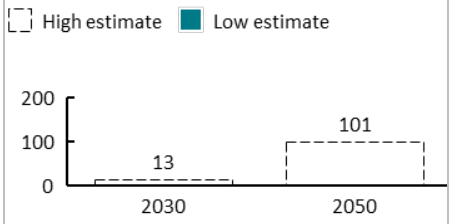
HEMS have significant opportunity to decarbonise commercial space heating and cooling

HEMS can contribute positively to systems innovation and new business model innovation for aggregators or TSO/DSO

Economic impacts

Potential market size (mEUR/year) is calculated from operator Total Cost of Ownership (TCOO, EUR/MW-year) and projected capacity uptake (MW). TCOO is the total cost of annualised CAPEX and OPEX

EU-27 potential market size, mEUR



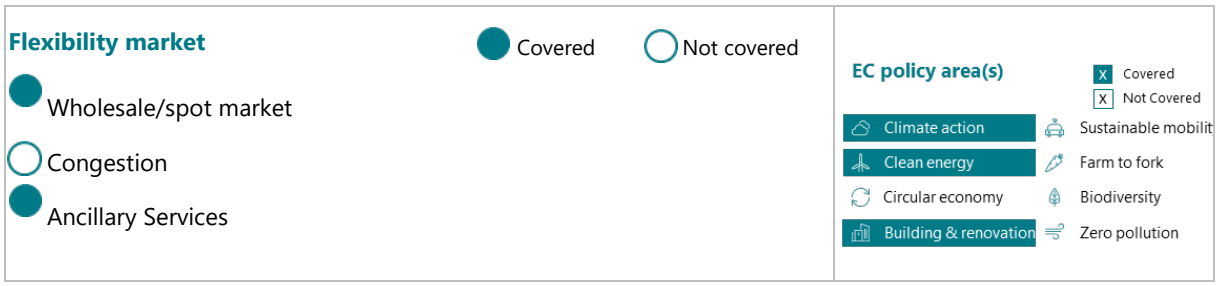
Cost of flexibility, excluding possible cost reduction from standardisation across Europe:

Capital expenses: EUR ~0–2,650 per megawatt year

Operating expenses: EUR ~0 per megawatt year

Total cost of ownership: EUR ~0–2,650 per megawatt year

The low range of €0 on Capex and Opex stems from the modern buildings having the required equipment by default



Selected players in the global BEMS market include Schneider Electric (France), Siemens (Germany), Honeywell (United States) and Johnson Controls (United States).

Feasibility

Near term maturity: This analysis projects a mature market by 2030. There are already numerous projects which integrates commercial buildings into the smart grid networks and provide flexibility services through their BEMS

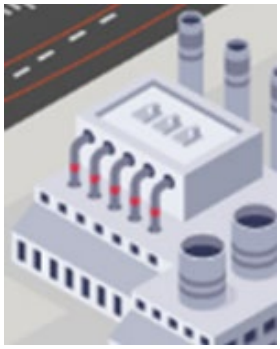
Commercial attractiveness: Low to moderate challenges are expected in the viability of this business case because of the significant projected margin. Potential benefits from ancillary services strongly depend on the type of connection between the BEMS and the TSO/DSO and the necessary infrastructural investments in the local grid substations. Fees, taxes and other additional expenses might reduce the projected margin.

Technical infrastructure requirements: Low to medium challenges are expected in the technical infrastructure requirements. The digital infrastructure includes integration into aggregator and TSO/DSO systems and requires robust cybersecurity, since without it the grid could be destabilised. Integrating ancillary services systems requires secure authorisation of TSO/DSO triggers and compatibility with the BEMS control system, and integration to external capacity and power markets is also necessary for accessing analytics tools.

Risk considerations: The main risks in this use case are in cybersecurity threats and in insufficient standardisation, if standards and prequalification requirements are not harmonised across Europe. Analysis indicates moderate risks and significant resolution effort in the following areas. Different standards and prequalification requirements across Europe may pose regulatory risks that could pose a barrier for suppliers of demand-side flexibility products[8]. Efforts are needed for defining unified standards on which the TSO/DSO can access and control the BEMS schedule. The business case of flexible BEMS would improve as EU-wide solutions become available. Cyberattacks result from increased use of ICT technologies for flexibility optimisation. For example, in 2017 Næstved District Heating in Denmark experienced a cyberattack that required DHC operators to pay to access files that had been encrypted in the servers.

Gamification potential: There are minor risks for gamification and strategic bidding, but no malicious intent is foreseen through the gamification process, since end-users cannot manipulate the power market to benefit themselves

Business case 6.2: Industrial hybrid heating



Industrial consumption is a significant share of overall energy and electricity consumption. Hybrid heating systems for industry can contribute to Fit for 55 and the Green Deal in two ways: 1) Decarbonisation of heating which currently relies on fossil fuel combustion and 2) provide flexibility to balance industrial power load. Hybrid heating means that while power is cheap, electric boilers would be used for process heating and fossil fuel boilers would be used at times of high power prices. In addition, switching between electricity or gas heating can also be used for grid balancing through electric load reduction/increase. Currently (2021) a significant number of hybrid heating systems are deployed in industry, with electric boilers providing low and medium heat up to 400 °C.

This business case focuses on the impact of hybrid heating systems using electric boilers for low and medium temperature heat. Industrial heat pumps can replace electric boilers in low and medium temperature heat once commercially available and are excluded from this BC for now.

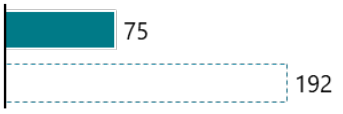
Impacts

Systemic impacts

The total adjustable power and energy equates to the (electrified) industrial heating capacity which can be heated by non-electric sources instead, and as such provide flexibility for intra- and interday flexibility, congestion management.

- Business Case: Industrial hybrid heating
- For comparison: Existing gas capacity/generation EU27 (2020)

Maximum adjustable power (GW)



Total adjustable energy (TWh)

Societal impacts

Industrial hybrid heating can improve the competitive position of industry with low and medium temperature heating, and as such contribute to job creation and job protection

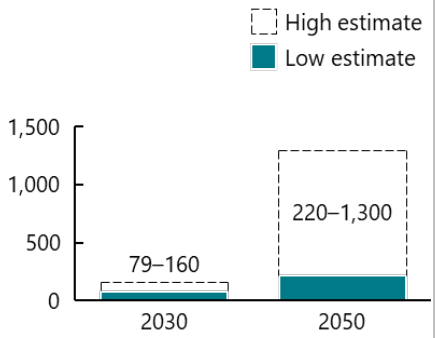
Other benefits include innovation in process redesign and equipment manufacturing, and industrial business models, and new business models being piloted targeting additional revenue streams

On the other hand, lack of opportunity awareness and coordination has been reported across stakeholders (operators, OEMs, research institutes)

Economic impacts

Potential market size (mEUR/year) is calculated from operator Total Cost of Ownership (TCOO, EUR/MW-year) and projected capacity uptake (MW). TCOO is the total cost of annualised CAPEX and OPEX

EU-27 potential market size, mEUR

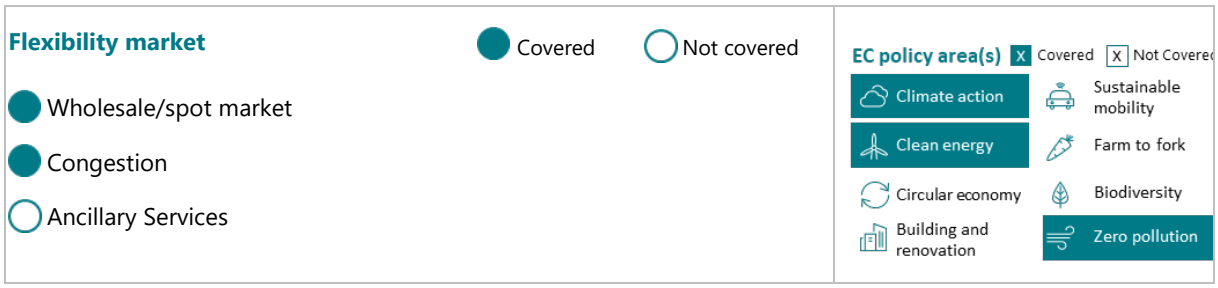


Cost of flexibility (electric boilers, 2021), excluding learning curve or technology cost reduction over time:

Capital expenses: EUR~170,000 per megawatt

Operating expenses: EUR ~10,000 per megawatt

TCOO: EUR ~12,700–23,200 per megawatt year



Selected players in the European hybrid heating market include Parat (Sweden), Zander & Ingestrom (Norway) and Cerney (Spain).

Feasibility

Near term maturity: High feasibility and widespread commercial application of hybrid heating systems may emerge by 2030. Currently 50% of industrial heat generation can be electrified (challenges remain in high temperature applications), and the monetisation of power price spread could possibly be an attractive new source of revenue.

Commercial attractiveness: While revenue potential looks positive, this assessment is highly uncertain due to significant uncertainty in estimating the underlying power prices, along with simplified estimations of revenues; for instance, focusing only on wholesale revenues and ignoring cannibalisation effects within and across business cases.

Technical infrastructure requirements: Overall, analysis shows a low level of technical challenges is likely. Half of existing industrial heat-generation capacity can be electrified for hybrid heating systems, and significant flexibility potential for intra- and interday and congestion-management services exist, with high ramp rates of electric systems and near 100% availability due to their hybrid nature.

Risk considerations: Potential risks could be experienced in relation to insurance cover, cybersecurity, industry end-user acceptance and gamification potential. These are moderate risks and need significant resolution effort. Financing for industrial energy innovation is subject to high interest rates. Electrification increases financial risk due to power-price variability, with the high interest rates reported. Therefore, financial risk coverage could be considered; for example, by providing insurance for risks that are out of the control of operators. A common EU strategy would help establish a reliable IoT communications for the energy system might lead to significant additional effort for operators and hamper effective cybersecurity measures. Lastly, general lack of knowledge and information in the process industry about technical possibilities has been indicated to be a risk to uptake

Gamification potential: The main low risk, which can be resolved, falls under the category of gamification potential. If electricity pricing and capacity markets move to a location-based model, transparency regarding congestion-management compensation, electricity pricing and other issues becomes extra important to minimise the possibility of market manipulation and so that industrial operators can evaluate business-case viability.

Business case 7.1: Residential heat pumps

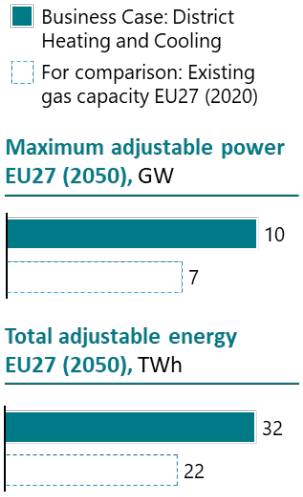
Residential heat demand is a significant share of overall energy consumption. Heat pumps can contribute to Fit for 55 and the Green Deal in two ways: Decarbonisation through electrification of heat generation and power flexibility to balance the power grid.

This business case focuses on flexibility provided by shifting the heat pump heat demand and power load. Since a very high share of the current and the future heat pumps stock constitutes from air-to-air heat pumps, in the potential impact analysis, the building thermal mass is used as a thermal storage. To do so, we have modelled 4 residential building types in four different European location. By considering the daily mean outside temperature and several different building refurbishment standards, the flexibility potentials offered by the building thermal mass were quantified for a selected EU-27 scenario up to year 2050. By adding water-based thermal storage (wherever technically possible) the flexibility potential can be adjusted depending on the size of the storage and heat pump capacity.

Impacts

Systemic impacts

The maximum adjustable power is based on the final energy demand (FED) for space heating, hot water, and space cooling, from 17.6% up to 35.3% of the thermal FED is identified as a flexible potential depending on the type of building, U-values, and climate zone.



Societal impacts

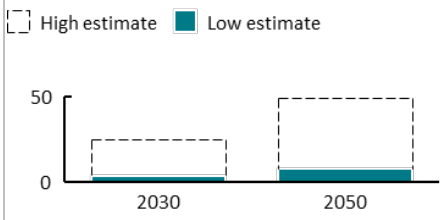
Heat pumps have significant opportunity to decarbonise residential heating, including from retrofitting

Flexibility provision through heat pumps can have positive impact on systems innovation and new business model innovation for aggregators or TSO/DSO

Economic impacts

Potential market size (mEUR/year) is calculated from operator Total Cost of Ownership (TCOO, EUR/MW-year) and projected capacity uptake (MW). TCOO is the total cost of annualised CAPEX and OPEX

EU-27 potential market size, mEUR

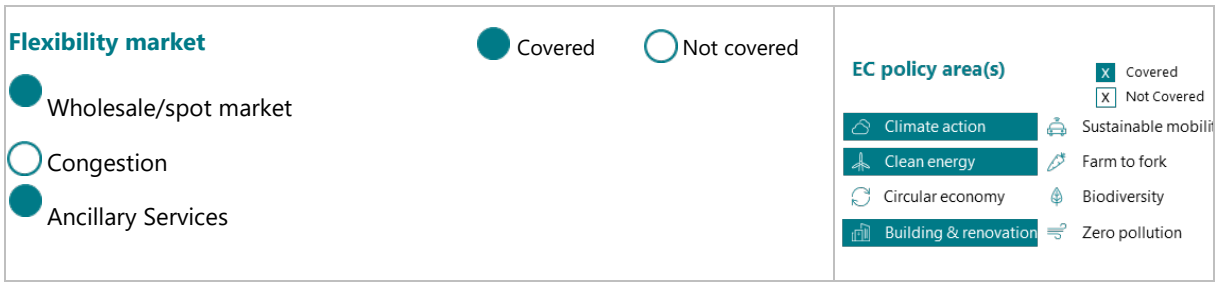


Cost of flexibility is estimated from:

Capital expenses: EUR ~0–5,200 per megawatt per year

Operating expenses: EUR ~1,000 per megawatt per year

Total cost of ownership: EUR ~1,000–6,200 per megawatt per year



Selected players in the EU transmission market with flexible tariffs for heat pumps include E.ON (Germany), EnBW (Germany), TenneT (The Netherlands) and Viessmann (Germany).

Feasibility

Near term maturity: This analysis projects flexibility capacity from residential heat pumps to be participating in commercial applications. Currently, most of the projects on residential heat pumps providing flexibility are pilots of local application. A number of companies already commercially offer flexibility as part of "smart heating solutions".

Commercial attractiveness: Revenues are generated from purchasing electricity for heating at times of lowest power prices and providing demand-response ancillary services in case of grid congestion. Analysis indicates low to medium challenges in monetising power price spreads from which heat pump flexibility can benefit. This is reflected in a significant projected margin, though it strongly depends on the type of connection between heat pumps and electricity markets, communication between heat pumps and the TSO/DSO, the necessary infrastructural investments in the local grid substations and changes in fiscal and non-fiscal charges. The revenue calculation is highly uncertain due to the difficulty of accurately predicting power prices and taxes and other effects are excluded in this analysis. Interactions among use cases on the electricity market prices are not taken into account.

Technical infrastructure requirements: Analysis suggests low to medium challenges in the technical infrastructure requirements around integration with TSO/DSO stability services and cybersecure remote control of electrified heat demand. Depending on the connection between the heat pump and the TSO/DSO, additional infrastructure could be required both in the grid and at customer premises.

Risk considerations: The main risks in this use case are in cyber security threats and insufficient standardisation across Europe. Differing standards and prequalification requirements across Europe are a major regulatory consideration. Efforts are needed to define unified standards for access and control of residential heat pumps so that they can react to TSO/DSO triggers. Cyberattacks on the electrified heating and cooling supply could also represent a risk for the electric grid, and could be directed explicitly at residential heat pumps, though the risk assessment is low since fragmentation of the market and standards might limit this to selected local grid areas

Gamification potential: There is a minor risk for gamification and strategic bidding if flexibility from heat pumps by aggregators is not coordinated.

Business case 7.3: Home energy management systems

HEMS and home batteries are used to optimise self-consumption of PV generation. Surplus capacities and storage can be used as flexibility and can be shared with the power market as well as with grid operators.

Diffusion of HEMS systems and home batteries is expected to grow due to the adoption of smart home technology and the end customer attractiveness of PV-battery-systems. With limited additional costs systems can be used to provide flexibility. In this business case building technologies (heating and cooling technologies) and electric cars are not considered.

Impacts

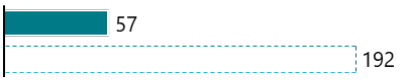
Systemic impacts

CE Delft analysed stationarity batteries for multiple types of prosumers (producing-consumers) and use cases. For the assessment of the potential only stationary batteries at households (for self-consumption), public entities and small enterprises are included

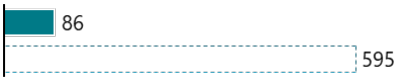
Business Case: HEMS/home batteries

Comparison: Existing gas capacity EU27 (2020)

Maximum adjustable power EU27 (2050), GW



Total adjustable energy EU27 (2050), TWh



Societal impacts

HEMS can provide an additional source of revenue for households, and already enjoy large public support

Grid operators could benefit from increased grid flexibility, frequency response and stabilisation

Battery manufacturers have opportunity to capture share in growth market beyond automotive

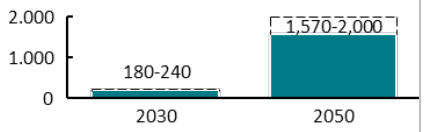
Economic impacts

Potential market size (mEUR/year) is calculated from operator Total Cost of Ownership (TCOO, EUR/MW-year) and projected capacity uptake (MW). TCOO is the total cost of annualised CAPEX and OPEX

EU-27 potential market size (TCOO) mEUR

High estimate

Low estimate



Cost of flexibility is estimated based on:

Capital expenses: EUR ~16,650–25,150 per megawatt year

Operating expenses: EUR ~5,000–7,500 per megawatt year

Total cost of ownership: EUR ~21,650–32,650 per megawatt year

Flexibility market

Covered

Not covered

- ● Wholesale/spot market
- ○ Congestion
- ○ Ancillary Services

EC policy area(s)

X Covered

X Not Covered

- Climate action
- Clean energy
- Circular economy
- Building & renovation
- Sustainable mobility
- Farm to fork
- Biodiversity
- Zero pollution

Selected players in the European stationary home battery market include Sonnen (Germany), LG Chem (South Korea) and BYD (China).

Feasibility

Near term maturity: Commercial application of this business case is projected for 2030. Currently, Germany and Italy are key markets with prequalification in place only in Germany, Italy and Switzerland.

Commercial attractiveness: HEMS and home battery use are highly dependent on regulatory frameworks, which could allow for providing households with relatively inexpensive, centrally generated green electricity. Cost is driven by battery capital expenditures and while it is expected to fall, overall profitability is uncertain due to possible regulatory changes regarding self-generated versus grid-generated electricity and flexibility incentives for prosumers. Analysis indicates moderate challenges in the viability of this business case.

Technical infrastructure requirements: Upgrading the grid connections may be required. Connecting stationary batteries to the grid is vital to setting up bidirectional communication, particularly with DSOs. Smart meters can sense energy market-signals and help home battery systems contribute to the flexibility market. The few challenges predominantly regard access to the TSO/DSO infrastructure and integrating secure advanced metering infrastructure

Risk considerations: The main risks for HEMS are in regulation, cybersecurity, industry end-user acceptance and gamification potential. These risks are low and are not likely to require complex resolution.

Gamification potential: Feed-in tariffs, which pay small-scale energy producers above-market for what they deliver to the grid and premiums on load shifting could encourage home battery storage on a large scale.

Business case 8.1: Price-responsive charging of electric vehicles

Due to high vehicle efficiencies, electric vehicles will be a dominant technology for passenger cars. Following this development, electricity demand from EVs will increase substantially in the future. This can pose challenges such as increasing demand peaks. However, if the charging of EVs can be coordinated, EVs also represent a substantial flexibility resource.

In the case of Smart Charging (also generally referred to demand response), the charging pattern of an EV is adjusted, i.e. the EV demand is shifted, based on a price signal, either from the overarching energy system or an incentive based on the local conditions. In this BC, we neglect fast-charging but assume no bottlenecks concerning charging infrastructure.

For this business case, both incentive-based charging mechanisms and control-based charging mechanisms are possible. The first means that EV users adapt their charging behaviour based on a price incentive (a tariff), the latter means that an overarching aggregator controls the charging process of a greater number of vehicles.

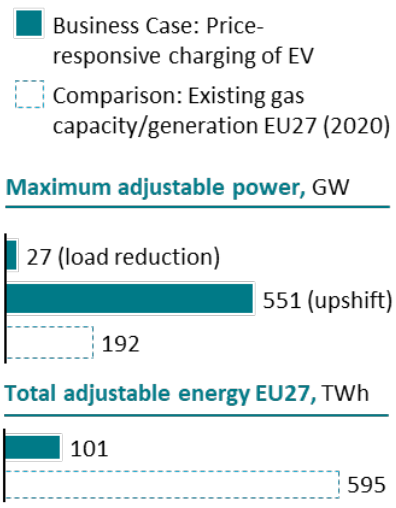
Impacts

Systemic impacts

The impact on emissions is heterogeneous (depends on emission intensity of underlying power generation) and can be positive in a power system with high share of renewables

Smart charging can reduce the power system cost by deferring capital investments for flexibility

Coordination with other flexibility resources is necessary



Societal impacts

Possibility for consumers to reduce electricity costs and participate actively in the energy transition

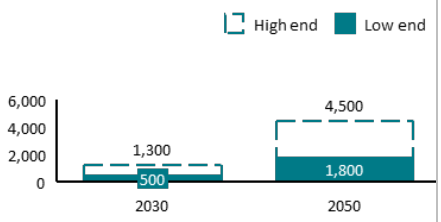
EV integration can result in further RES integration and reduction of greenhouse gas emissions

On the other hand, EV users may experience reduced convenience

Economic impacts

Potential market size (mEUR/year) is calculated from operator Total Cost of Ownership (TCOO, EUR/MW-year) and projected capacity uptake (MW). TCOO is the total cost of annualised CAPEX and OPEX

EU-27 potential market size, mEUR

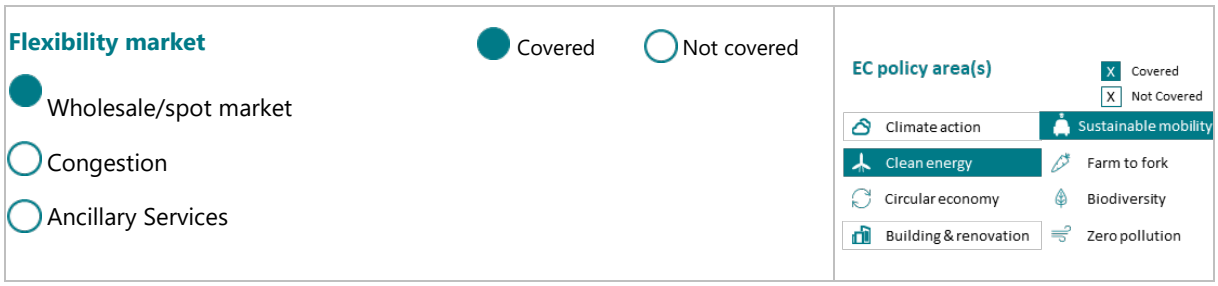


Cost of flexibility is estimated from:

Capital expenses: EUR ~0 per megawatt year

Operating expenses: EUR ~72,000 per megawatt year

Total cost of ownership: EUR ~72,000 per megawatt year



Selected players in the EV charging infrastructure and services market include Ionity (Germany), Virta (Finland) and Bosch (Germany).

Feasibility

Near term maturity: This analysis suggests that smart charging will be in commercial application by 2030. Products and services are increasingly available to household consumers (smart tariffs and corresponding charging & metering infrastructure currently emerge – both from established and upcoming companies). In addition, charging technologies and necessary protocols exist to facilitate smart charging.

Commercial attractiveness: Analysis suggests moderate challenges in the viability of smart charging for flexibility (BC 8.1), since its profitability depends heavily on price spreads and taxes, and retail power price differences among countries.

Technical infrastructure requirements: Analysis suggests few challenges in the technical requirements for smart charging. The adoption of EVs is ongoing; charging, metering and communication protocols exist, and the smart meter roll-out is ongoing throughout Europe

Risk considerations: Risks could be experienced in relation to public and end-user acceptance, cybersecurity, gamification potential and technical barriers. End user acceptance should address data privacy concerns and depth of discharging, which affects end user comfort. Technical risks arise from the current optimisation to vehicle performance (speed of charging) instead of consideration of flexibility. Increased standardisation could improve the cyber security of products and services.

Gamification potential: As a relatively small flexibility resource, individual EVs have limited market power, so the gamification potential of price-responsive charging is also limited. However, gamification potential cannot be excluded, since the aggregator could participate in multiple markets at once. Therefore, two aspects of gamification are relevant. (1) increasing market power in primary power markets due to vast flexibility potential: i.e., an aggregator could exert outsized market power by concentrating a large number of EVs, and (2) (de)centralised secondary markets; particularly in small grid areas, an aggregator might have sufficient leverage to manipulate a decentralised secondary market

Business case 8.3: Self-consumption optimisation using electric vehicles

In the case of self-consumption, EV charging aims for the maximisation of self-supply of households with a renewable electricity supply unit. Self-consumption can be defined as the 'PV production consumed directly by the producer, which is often the owner of the PV system'. Rising electricity end-user prices and falling prices for PV systems on the other imply that self-consumption is an economically attractive option of using rooftop PV systems. If an EV is added to the household demand, this changes both the amount of electricity consumed in the household and the household load profile considerably. EVs are particularly charged during the morning, evening and night time hours and, thus, not necessarily during the period of the day when PV generation peaks. Nevertheless, integrating EVs into a self-consumption scheme increases the share of energy from the PV unit that is consumed within the household.

The main drivers for the flexibility potential of this business case are the number of PV units on European rooftops, the share of which with an EV and their household demand. In the framework of self-consumption, EV charging targets the maximisation of a households self-supply (the minimisation of the PV generation induced to the grid). Consequently, the maximum EV load upshift potential is restricted by the households residual PV generation.

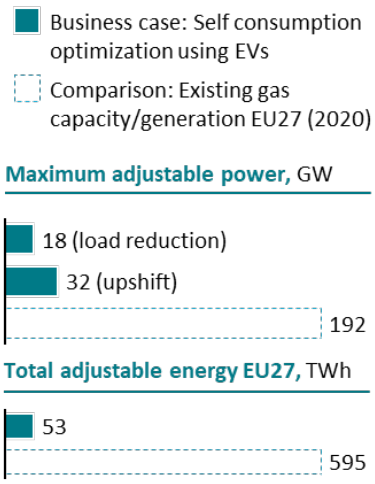
Impacts

Systemic impacts

The impact on emissions is heterogeneous (depends on emission intensity of underlying power generation) and can be positive in a power system with high share of renewables

Self-consumption does not necessarily decrease load peaks in the grid

Self-consumers reduce their contribution to the grid charges while still make use of the grid infrastructure



Societal impacts

EV integration can could create the possibility for consumers to reduce electricity costs and participate actively in the energy transition

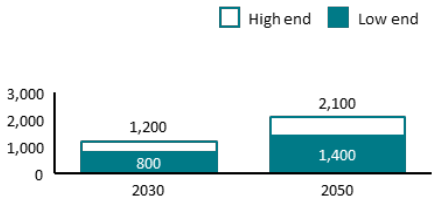
EV integration can result in further RES integration and reduction of greenhouse gas emissions

On the other hand, EV users may experience reduced convenience

Economic impacts

Potential market size (mEUR/year) is calculated from operator Total Cost of Ownership (TCOO, EUR/MW-year) and projected capacity uptake (MW). TCOO is the total cost of annualised CAPEX and OPEX

EU-27 potential market size, mEUR

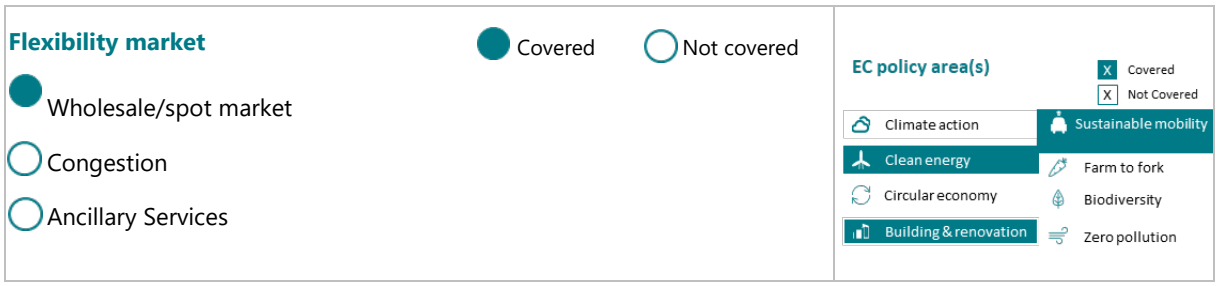


Cost of flexibility is estimated based on:

Capital expenses: EUR ~0 per megawatt year

Operating expenses: EUR ~59,000 per megawatt year

Total cost of ownership: EUR ~59,000 per megawatt year



Selected players in the EV charging infrastructure and services market include Ionity (Germany), Virta (Finland) and Bosch (Germany).

Feasibility

Near term maturity: This analysis suggests that self-consumption optimisation using EVs will be a mature market by 2030. Products and services already exist and are generally financially attractive, and charging technologies are available and used by household consumers.

Commercial attractiveness: While the revenues and saved electricity cost look positive, this assessment is highly uncertain due to significant uncertainty in estimating the underlying retail prices, fiscal charges, and regulations for self-consumption, both in the future and from country to country.

Technical infrastructure requirements: Analysis suggests few challenges in the technical requirements for smart charging. The adoption of EVs is ongoing; charging, metering and communication protocols exist, and the smart meter roll-out is ongoing throughout Europe

Risk considerations: Risks could be experienced in relation to public and end-user acceptance, cybersecurity, gamification potential and technical barriers. End user acceptance should address data privacy concerns and depth of discharging, which affects end user comfort. Technical risks arise from the current optimisation to vehicle performance (speed of charging) instead of consideration of flexibility. Increased standardisation could improve the cyber security of products and services.

Gamification potential: As a relatively small flexibility resource, individual EVs have limited market power, so the gamification potential of price-responsive charging is also limited. However, gamification potential cannot be excluded, since the aggregator could participate in multiple markets at once. Therefore, two aspects of gamification are relevant. (1) increasing market power in primary power markets due to vast flexibility potential: i.e., an aggregator could exert outsized market power by concentrating a large number of EVs, and (2) (de)centralised secondary markets; particularly in small grid areas, an aggregator might have sufficient leverage to manipulate a decentralised secondary market

Business case 9.1: Price/incentive-responsive bidirectional charging

Driven by price signals like the ones for smart charging and given the necessary technical set-up is available, vehicles are able to adapt their charging pattern (load upshift) but also to induce electricity back to the grid (discharge to grid). Due to the bidirectional charging capacity (the so-called vehicle-to-grid, V2G), the flexibility potential per vehicle is high. However, considering that V2G is currently in a pilot stage concerning EVs, charging technology and software, the adoption rate of this BC is assumed to be lower than for other EV cases.

Impacts

Systemic impacts

The impact on emissions is heterogeneous (depends on emission intensity of underlying power generation) and can be positive in a power system with high share of renewables

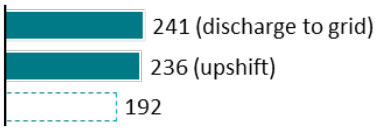
Coordination with other flexibility resources is necessary

Vehicle to grid gives large leverage for renewables integration and peak shaving, from ability to (dis)charge in response to price incentive

Business Case: Price-responsive charging of EV

Comparison: Existing gas capacity/generation EU27 (2020)

Maximum adjustable power, GW



Total adjustable energy EU27, TWh

Societal impacts

EV integration can could create the possibility for consumers to reduce electricity costs and participate actively in the energy transition

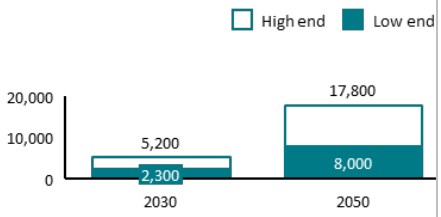
EV integration can result in further RES integration and reduction of greenhouse gas emissions

On the other hand, EV users may experience reduced convenience

Economic impacts

Potential market size (mEUR/year) is calculated from operator Total Cost of Ownership (TCOO, EUR/MW-year) and projected capacity uptake (MW). TCOO is the total cost of annualised CAPEX and OPEX

EU-27 potential market size, mEUR



Cost of flexibility is estimated based on:

Capital expenses: EUR ~53,000–64,000 per megawatt year

Operating expenses: EUR ~10,000 per megawatt year

Total cost of ownership: EUR ~63,000–74,000 per megawatt year

Flexibility market

Covered / Not covered

- Wholesale/spot market
- Congestion
- Ancillary Services

EC policy area(s)

X Covered
X Not Covered

- Climate action
- Sustainable mobility
- Clean energy
- Farm to fork
- Circular economy
- Biodiversity
- Building & renovation
- Zero pollution

Selected players in the global V2G market include Ionity (Germany), The Mobility House (Germany) and Nuvve (United States).

Feasibility

Near term maturity: Based on this analysis it is estimated that bidirectional price-incentive charging will be in pilot phase towards initial commercial application by 2030. Products and services are still in development. Charging technologies and necessary protocols exist but significant standardisation is required before commercial application at scale.

Commercial attractiveness: While the revenues look positive, this assessment is highly uncertain since it's difficult to estimate underlying power prices and revenue estimates are simplified, focusing only on wholesale revenues and ignoring cannibalisation effects within and across business cases.

Technical infrastructure requirements: Analysis suggests moderate challenges in the technical requirements for V2G. A limited number of vehicle manufacturers and V2G infrastructure manufacturers currently exists, and infrastructure is more costly than single directional smart charging.

Risk considerations: V2G presents higher risks than smart charging (BC 8.1, 8.3). Bidirectional charging will depend on third-party and cloud infrastructure to larger extent and is therefore foreseen to have a higher cybersecurity risk. Currently, interfaces are not standardised which further creates exposure. Technical risks exist in the current small number of manufacturers of both bi-directional charging infrastructure and EVs compatible with bidirectional charging. Lastly, end-user acceptance is a risk to this business case as it has larger impact on user comfort (in terms of availability of a charged vehicle).

Gamification potential: The gamification potential for V2G is the same as that for smart charging, but with an additional risk. Because both charging and discharging affect the grid with V2G, each EV can have double the effect a single EV has with V1G, increasing the risk that individual aggregators of EVs can exert outsized market power.

Business case 9.2: Congestion management and ancillary services using V2G

Load shifting and bidirectional charging specifically for grid balancing measures, driven/requested by the grid operator

Due to minimum capacity requirements during prequalification for the participation in an ancillary market, participation is only feasible, if EV flexibility resources are pooled. Moreover, capacity is reserved in advance and separately from the provision of balancing power. Therefore, the service provider has to ensure that the reserved capacity can actually be dispatched.

Impacts

Systemic impacts

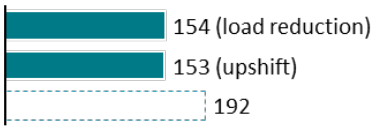
The impact on emissions is heterogeneous (depends on emission intensity of underlying power generation) and can be positive in a power system with high share of renewables

Coordination with other flexibility resources is necessary

Vehicle to grid gives large leverage for renewables integration and peak shaving, from ability to (dis)charge in response to price incentive

- Business Case: Price-responsive charging of EV
- Comparison: Existing gas capacity/generation EU27 (2020)

Maximum adjustable power, GW



Total adjustable energy EU27, TWh

Societal impacts

EV integration can could create the possibility for consumers to reduce electricity costs and participate actively in the energy transition

EV integration can result in further RES integration and reduction of greenhouse gas emissions

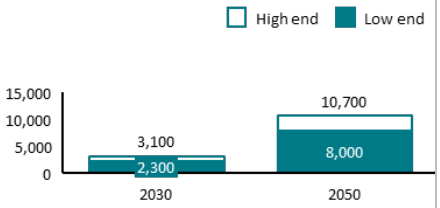
EV integration could have positive effect on grid operating cost through savings (more efficient provision)

On the other hand, EV users may experience reduced convenience

Economic impacts

Potential market size (mEUR/year) is calculated from operator Total Cost of Ownership (TCOO, EUR/MW-year) and projected capacity uptake (MW). TCOO is the total cost of annualised CAPEX and OPEX

EU-27 potential market size, mEUR



Cost of flexibility or total cost of ownership estimated as EUR ~83,000–96,000 per megawatt year

Flexibility market

- (●) Wholesale/spot market
- ( ) Congestion
- ( ) Ancillary Services

(●) Covered ( ) Not covered

EC policy area(s)

X Covered
X Not Covered

Climate action	Sustainable mobility
Clean energy	Farm to fork
Circular economy	Biodiversity
Building & renovation	Zero pollution

Selected players in the EV charging infrastructure and services market include Ionity (Germany), Virta (Finland) and Bosch (Germany).

Feasibility

Near term maturity: This analysis suggests that ancillary services using EVs will be in pilot phase towards initial commercial application by 2030. Products and services are still in development. Charging technologies and necessary protocols exist but significant standardisation is required before commercial application at scale.

Commercial attractiveness: Projected revenues look marginal or even negative in this assessment. This assessment is highly uncertain since it's difficult to estimate underlying future power and ancillary services prices, and does not consider taxes and fees, or differences among countries. Smaller margin stems from a higher TCOO compared to V2G price-incentive charging/discharging, in turn from smaller capacity per EV available for this business case.

Technical infrastructure requirements: Analysis suggests few challenges in the technical requirements for smart charging. The adoption of EVs is ongoing; charging, metering and communication protocols exist, and the smart meter roll-out is ongoing throughout Europe

Risk considerations: Risks could be experienced in relation to public and end-user acceptance, cybersecurity, gamification potential and technical barriers. End user acceptance should address data privacy concerns and depth of discharging, which affects end user comfort. Technical risks arise from the current optimisation to vehicle performance (speed of charging) instead of consideration of flexibility. Increased standardisation could improve the cyber security of products and services.

Gamification potential: As a relatively small flexibility resource, individual EVs have limited market power, so the gamification potential of price-responsive charging is also limited. However, gamification potential cannot be excluded, since the aggregator could participate in multiple markets at once. Therefore, two aspects of gamification are relevant. (1) increasing market power in primary power markets due to vast flexibility potential: i.e., an aggregator could exert outsized market power by concentrating a large number of EVs, and (2) (de)centralised secondary markets; particularly in small grid areas, an aggregator might have sufficient leverage to manipulate a decentralised secondary market.

A.2 Appendix B Companies analysed in Chapter 15: International and intersectoral experience, by business case

Business case 2.1 Distributed Energy Resource Management Systems (DERMS)

Table 29. Selected examples of companies and other entities related to the DERMS business case evaluation and the closely related Advanced Demand Management Systems (ADMS) business cases

Company name	Company description
ABB	ABB is a multinational corporation specialising in robotics, power, automation and heavy electrical equipment
Alfen	Alfen offers grid automation (Alfen Connect) and internet-connected charging equipment
Ampacimon	Ampacimon offers electricity grid monitoring products.
Camus Energy	Camus offers grid management platforms for grid visibility and advanced control
Cepsa International	Cepsa is a global and integrated energy company
Comverge	Comverge delivers software, hardware, and services to help electric utilities deploy demand response programmes
Efacec	Efaces provides energy solutions in power transformation, automation, switchgear and mobility solutions in EV charging
Electron	Electron is a facilitator of small scale, market-based interactions
Enbala	Enbala is a provider of DERMS software systems; it was acquired by Generac in 2020
ENTSO-E	ENTSO-E (the European Network of Transmission System Operators for Electricity) represents 42 TSOs from 35 countries across Europe
Envelio	envelio is a cloud-based smart grid platform.
Equigy	Equigy is a transnational blockchain platform developed by the four largest European transmission system operators, TenneT (Germany and the Netherlands), Swissgrid (Switzerland) and Terna (Italy) in April 2020.
Esmart Systems	eSmart Systems' software solution Grid Vision® aims to optimise infrastructure inspections.
FSIGHT	fsight.OPTIMISE is an end-to-end automated optimisation & trading platform
General Electric	GE's is a multinational provider of power, automation and heavy electrical equipment and provides advanced distribution management systems (ADMS) software for distribution system operators.
Grid Solutions	Grid Solutions provides power equipment, systems and services.
Grid4c	Grid4c provides predictive analytics solution for the energy industry.
Heimdall power	Heimdall Power provides smart grid solutions.

Company name	Company description
Laki Power	Laki Power provides line monitoring tools.
Limejump Limited	Limejump is a technology platform that manages a large renewable energy network.
Lindsay Manufacturing Company	Lindsay provides grid resiliency, smart grid and T&D hardware products.
LineVision, Inc.	LineVision provides power grid sensors.
Lockheed Martin Corporation	Lockheed Martin provides a range of services, including renewable energy integration to storage, efficiency, demand response and microgrids
Opus One Solutions Energy Corporation	Opus One's GridOS Platform offers model-based optimisation for distribution grids.
Otlm Knill gruppe	OTLM system is a solution for monitoring, rating and managing overhead lines.
Pecan Street Inc.	Pecan Street provides consumer data on energy and water consumption behaviour.
Plexigrid	Plexigrid provide tailored solutions for electricity systems by using data analysis and optimisation technology.
Power Analytics Corporation	Power Analytics is a provider of professional engineering services and a developer of power system design, simulation, and power system analytics software.
Schneider Electric SE	Schneider Electric SE is a French multinational corporation providing energy and automation digital solutions for efficiency and sustainability.
Siemens AG	Siemens AG is a German multinational conglomerate offers smart grid and power distribution systems and services.
Smart Grid Solutions	Smarter Grid Solutions is a software company providing DERMS systems.
Spirae Inc.	Spirae provides solutions for integration of distributed renewable energy sources.
Swissgrid	Swissgrid is the Swiss transmission system operator.
TenneT	TenneT is the Dutch transmission system operator, with operations in part of the German transmission grid.
Utilidata, Inc	Utillidata provides a grid-edge operating platform for power grid operations.
Venios GmbH	Venios provides grid monitoring software.
Viesgo Corporate	Viesgo, is an electricity distribution company with a network stretching around the north of Spain.
Viridity Energy Solutions, Inc.	Viridity Energy Solutiosn provides energy demand response management and storage solutions.
PGE Polska Grupa Energetyczna SA	PGE is a Polish state-owned public power company.
EON SE	E.ON is an international energy company.
I-DE Redes Electricas Inteligentes, S.A.U.	I-DE REI is an electricity distribution company part of Iberdrola.

Company name	Company description
Western Power Distribution Plc	WPD is the electricity distribution network operator for the Midlands, South Wales and the South West of England

Use case: Virtual Power Plants (Business cases 3.1, 3.2 and 3.5)

Table 30. Selected examples of companies to all business cases within the use case VPPs

Company name	Company description
AutoGrid Systems Inc.	AutoGrid is a software company providing smart grid solutions.
Axpo Solutions AG	Axpo is active in electricity production, distribution and trading.
GreenSync	GreenSync is a global energy tech company.
Gridcognition	Gridcognition is a cloud-hosted software platform for grid planning and operations.
Leap Power, Inc.	Leap provides software for participation in demand response markets.
Sympower Oy	Sympower is a virtual power plant operator.

Business case 4.1 Energy sharing and peer-to-peer trading

Table 31. Selected examples of companies to business case 4.1 Energy sharing and peer-to-peer trading

Company name	Company description
gridx	GridX provides cloud-based business operation support systems.
Husk Power Systems	Husk provides rural energy services
tibber	Tibber is a digital electricity supplier.

Business case 4.4 District heating and cooling

Table 32. Selected examples of companies to business case 4.4 District heating and cooling

Company name	Company description
Beijing District Heating Group	Beijing District Heating Group provides heating services for government, army, hotel, residence, and other areas.
Engie SA	ENGIE is a French multinational utility company.
Fortum Oyj	Fortum offers district heating and cooling.
GS Global	GS Global is a South Korean conglomerate with activities in (among others) energy and power.

Company name	Company description
Helen Ltd	Helen Ltd is an energy production company with activities in district heating and cooling.
Korea District Heating Corporation	KDHC is a South Korean operator of district heating networks
MVV Energie	MVV is an energy supplier in Germany and wider Europe.
Noda Intelligent Systems AB	NODA provides heating and cooling optimisation solutions.
Pacific Gas and Electric Company	Pacific Gas and Electric Company is a combined natural gas and electric energy company in the United States.
Polskie Górnictwo Naftowe i Gazownictwo S.A. (PGNIG)	PGNiG operates in power generation and heat distribution.
Stockholm Exergi AB	Stockholm Exergi provides heat, cooling and electricity.

Business case 5.1 Building energy management systems (BEMS) for commercial buildings

Table 33. Selected examples of companies to business case 5.1 BEMS

Company name	Company description
75fahrenheit LLC	75F provides provides building energy management software solutions.
Dabble	DABBEL provides building energy management software solutions.
Enerbrain	Enerbrain provides building energy management software solutions.
Enlighted, Inc	Enlighted provides building energy management software solutions.
GridPoint, Inc	GridPoint provides data-driven energy management solutions (EMS).
Measurabl, Inc	Measurabl is a software company aimed at tracking ESG metrics.
Microsoft Corporation	Microsoft is a multinational technology company
PassiveLogic Inc	PassiveLogic's provides building energy management systems.
Planon Group B.V.	Planon is a global software provider.
Senfal	Senfal provides software services to industrial customers, wind and solar farms as well as battery owners.
SENSORFLOW PTE Ltd	SensorFlow provides wireless automation and energy management solutions.
Telkonet, Inc	Telkonet provides responsive solutions to building occupants.
Verdant Environmental Technologies	Verdant provides energy management thermostats.
VoltServer, Inc	VoltServer is an electricity provider.
Wattics, Ltd	Wattics provides energy monitoring systems.
Zenatix Solutions	Zenatix provides connected infrastructures.

Business case 6.2 Industrial hybrid heating

Table 34. Selected examples of companies to business case 6.2 Industrial hybrid heating

Company name	Company description
Millennial Net, Inc.	Millennial Net provides energy management solutions and sensor networks.
Next Kraftwerke GmbH	Next Kraftwerke operates a Virtual Power Plants and has been acquired by Shell in 2021.
P. M. Lattner Manufacturing Company	Lattner Boiler manufactures both fuel-fired and electric boilers for a variety of industrial applications.
PARAT Halvorsen AS	Parat Halvorsen is a Norwegian supplier of steam and heat solutions.
Recoy B.V.	Recoy provides energy flexibility forecasting and optimisation solutions.
Vapec AG	VAPEC is a company that specialises in the manufacture and maintenance of industrial boiler plants.
Vapor Power International, LLC	Vapor Power provides steam and heat solutions.
Vivavis AG	Vivavis provides IoT solutions for (energy) infrastructure.
Zander & Ingestrom AB	Zander & Ingestrom provide pumping and heat solutions.

Business case 7.1 Residential heat pumps

Table 35. Selected examples of companies to business case 7.1 Residential heat pumps

Company name	Company description
n/a – No company profiles were evaluated for this business case	n/a – No company profiles were evaluated for this business case

Business case 7.3 Home energy management systems (HEMS)

Table 36. Selected examples of companies to business case 7.3 home energy management systems (HEMS)

Company name	Company description
carbonTRACK	carbonTRACK provides network infrastructure, control systems and analytical solutions.
Curb, Inc.	CURB provides energy monitoring solutions.
Efergy Technologies	Efergy provides energy monitoring solutions.
Generac Power Systems, Inc.	Generac provides home backup generators.
Honeywell International Inc.	The Company provides aerospace products and services, control, sensing and security technologies.

Company name	Company description
innogy (now E.ON Energie Deutschland)	Innogy SE was an energy company based in Essen, Germany. It is now merged and integrated into German energy company E.ON.
International Business Machines Corporation	IBM is an American multinational technology corporation.
OVO Energy Ltd	OVO provides smart meters, electric vehicle chargers and smart storage heaters.
Sense	Sense's AI provides detection and smart home solutions.
Smappee	Smappee develops energy solutions.
Smarter Homes LLC	Smarter Homes provides residential power generation, home automation and management devices.
Solar Analytics Pty Ltd	Solar Analytics provides solar software systems.
Tado	Tado provides home energy management solutions.
TED – The Energy Detective	TED provides software solutions for remote data integration.
Uplight, Inc	Uplight provides services to energy providers and their customers.
Vodafone Group Plc	Vodafone is a multinational technology communications company

Business case 8.1 Price-responsive charging of EVs and Business case 8.3 Self-consumption optimisation using EVs

Table 37. Selected examples of companies to business case 8.1 price-responsive charging of EVs and 8.3 Self-consumption optimisation using EVs

Company name	Company description
ChargePoint Inc	ChargePoint provides EV charging solutions.
Easee AS	Easee provides a smart charging robot for EVs
EnelX	The company provides electric mobility, smart home technologies and business-ready products and services.
Gridio 2.0 OU	Gridio is a smart energy platform.
Hager Group	Hager Group is a supplier of solutions and services for electrical installations in residential, commercial and industrial buildings.
Heliox Energy	Heliox provides smart energy management solutions
Jedlix BV	Jedlix provides EV charging services.
Kiwigrid GmbH	Kiwigrid aims to help businesses succeed in a new energy and mobility world
Newmotion	newmotion offers charging solutions for car manufacturers, leasing companies and businesses.
The Mobility House GmbH	The Mobility House provides charging and energy solutions.
Tritium	Tritium provides DC chargers for EVs.
Ubitricity GmbH	Ubitricity provides EV grid integration solutions.
Vattenfall	Vattenfall is a Swedish multinational power company.
Virta Global	Virta provides EV charging business platforms.

Company name	Company description
Wallbe GmbH	Wallbe provides EV charging control solutions
Zaptec AS	Zaptec provides EV charging infrastructure.
IONITY GmbH	IONITY operates a charging network for electric vehicles.
GreenFlux Assets B.V.	Greenflux provides charging solutions for automotive industry.
Last Mile Solutions B.V.	Last Mile Solutions operates EV charging infrastructure.

Business case 9.1 Price-responsive grid charging and discharging of EVs (V2G) and Business case 9.2 Congestion management and ancillary services using EVs (V2G)

Table 38. Selected examples of companies to business cases 9.1 price-responsive grid charging and 9.2 congestion management and ancillary services using EVs

Company name	Company description
EDP – Energias de Portugal	EDP is a Portuguese electric utilities company.
EVBox	EVBox provides charging solutions for business and households.
Kaluza	Kaluza provides an energy flexibility optimisation platform.
NUVVE	Nuvve provides V2G charging services

Responsibilites by chapters

Chapters 2 (Task 1.1)

→ lead: McKinsey & Company Inc., supported by Fraunhofer ISI and Fraunhofer IEE

Chapters 3-14 (Task 1.2)

→ lead: McKinsey & Company Inc., supported by Fraunhofer ISI and Fraunhofer IEE

Chapter 15 (Task 2.1)

→ lead: McKinsey & Company Inc., supported by Fraunhofer ISI and Fraunhofer IEE

Chapter 16 (Task 2.2)

→ lead: Fraunhofer ISI supported by Fraunhofer IEE

Chapter 17 (Task 3)

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